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, 2000

COMMISSION FILE NUMBER 0-25192

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

<TABLE>

<S>	<C>
DELAWARE	64-0844345
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(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 NORTH CANAL STREET NATCHEZ, MISSISSIPPI 39120	(601) 442-1601
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(Address of Principal Executive Offices)(Zip Code)	(Registrant's telephone number including area code)

</TABLE>

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

<TABLE>
<CAPTION>

TITLE OF EACH CLASS	NAME OF EXCHANGE ON WHICH REGISTERED
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<S>	<C>
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
10.25% Senior Subordinated Notes due 2004	New York Stock Exchange
11.00% Senior Subordinated Notes due 2005	New York Stock Exchange

</TABLE>

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 .
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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 $125,850,000 as of March 16, 2001 (based on the last reported sale price of such stock on the New York Stock Exchange).

As of March 16, 2001, there were 13,353,223 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, 2000) relating to the Annual Meeting of Stockholders to be held on May 4, 2001, which is incorporated into Part III of this Form 10-K.

PART I.

ITEM 1. BUSINESS

OVERVIEW

Callon Petroleum Company (the "Company") has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. The Company's properties are geographically concentrated primarily offshore in the Gulf of Mexico and onshore in Louisiana and Alabama. The 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" refers to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

In 1989, the Company began increasing its 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. The Company focused on reducing operating costs and implementing production enhancements through the application of technologically advanced production and recompletion techniques.

Over the past five years, the Company has also placed emphasis on the acquisition of acreage with exploration and development drilling opportunities in the Gulf of Mexico Shelf area. The Company acquired an infrastructure of production platforms, gathering systems and pipelines to minimize development expenditures of these drilling opportunities. The Company 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). During this past five-year period, Callon has drilled 26 productive wells and 16 dry holes for a total of 42 wells and a success rate of 62%. These 26 productive wells include 3 onshore, 17 in the Gulf of Mexico Shelf area and 6 in the deepwater region of the Gulf.

The Company ended the year 2000 with estimated net proved reserves of 334 billion cubic feet of natural gas equivalent ("Bcfe") and a reserve replacement rate of 584%. This represents an increase of 28% over 1999 year-end estimated net proved reserves of 259 Bcfe.

The major focus of the Company's 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 area 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 $82 million in 2000. The Company incurred approximately $32.6 million in the Gulf of Mexico Shelf area primarily in the development of the 1999 discoveries at South Marsh Island 261 and East Cameron Block 275. Included in these expenditures as exploration costs, is approximately $7.5 million related to three unsuccessful Gulf of Mexico Shelf prospects evaluated during 2000. The Gulf of Mexico Deepwater area expenditures accounted for the remainder of the total capital expended, along with $5.8 million incurred in leasehold and seismic acquisition costs and $11.9 million of interest and general and administrative costs allocable directly to exploration and development projects. The Gulf of Mexico Deepwater area expenditures included three unsuccessful exploration projects totaling $9.3 million and the balance was incurred for additional delineation drilling at the Company's Medusa discovery and the drilling of a test well and delineation drilling at the Entrada discovery in 2000. The Entrada discovery is located on Garden Banks Block 782, and reached total depth in April 2000.

As a result of recent successes in the Gulf of Mexico Deepwater area, the Company is faced with increased costs to develop these significant proved undeveloped reserves. Substantially all of the future development costs will be incurred in 2001 and beyond. The Company is currently evaluating various financing alternatives to address these issues. While management believes there are a number of financing sources available to the Company, no assurances can be made that the Company 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.

Also, because of the short life of our reserves, our return on the investment we make in our oil and gas wells and the value of our oil and gas wells will depend significantly on prices prevailing during relatively short production periods.

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 2000, about 57% of our daily production came from three of our properties in the Gulf of Mexico. Moreover, one property accounted for 35% 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, 2000 most of our proved reserves were located in 11 fields in the Gulf of Mexico, with approximately 90% of our total net proved reserves attributable to five of 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 DEEP WATER 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 deep water 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 DEEP WATER OPERATIONS HAVE SPECIAL OPERATIONAL RISKS THAT MAY NEGATIVELY AFFECT THE VALUE OF THOSE ASSETS. Drilling operations in the deep water 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. Deep water 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 deep water, the time required to commence production following a discovery is much longer than in shallow water and on-shore. Our deep water 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 deep water wells;
- the availability of materials necessary to construct the facilities;
- 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 deep water prospects and the discounted present value of reserves attributable to those prospects.

COMPETITIVE INDUSTRY CONDITIONS MAY NEGATIVELY AFFECT OUR ABILITY TO CONDUCT OPERATIONS. Exploration in the Gulf of Mexico has recently received renewed interest, especially among major integrated oil companies and large independent oil companies. The acquisition of exploration prospects, producing properties and production facilities in the Gulf of Mexico is highly competitive. Factors which affect our ability to successfully compete are:

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

Our competitors include major integrated oil companies and large independent energy companies, many of which have greater financial and other resources.

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. Our current capital budget includes drilling 7 gross (1.1 net) development wells and 21 gross (9.9 net) exploratory wells through fiscal 2001. The estimated cost, net to us, to drill and complete these wells is approximately $73 million. The estimated dry hole costs to drill these wells, which are the costs we would incur if all of the wells were unsuccessful and we incurred no completion costs, are approximately $38 million. 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 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 will 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. Estimating quantities of proved reserves is inherently imprecise and involves uncertainties and factors beyond our control. The reserve data in this report represent only estimates. These estimates are based upon assumptions about future production levels, future oil and gas prices and future operating costs. As a result, the quantity of 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 deep water wells used in preparing our reserves are subject to revisions over time as described under " -- Our deep water operations have special operational risks that may negatively affect the value of those assets." Information about reserves constitutes 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, 2000, approximately 58.2% 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 deep water 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 hurricanes and other adverse weather conditions. 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 discharge of materials into the environment or otherwise relating to environmental protection. 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 and costs, 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;

- 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;

- volatility of oil and natural gas prices;

- uncertainty of estimates of oil and natural gas reserves;

- impact of competition;

- 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;

- 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

- climatic 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

The Company's headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. In late 2000, the Company opened a field office in Houston, Texas, staffed with recently hired technical professionals, to enhance exploration and development efforts. The Company also maintains owned or leased field offices in the area of the major fields in which it operates properties or has a significant interest. Replacement of any of the Company's leased offices would not result in material expenditures by the Company as alternative locations to its leased space are anticipated to be readily available.

EMPLOYEES

The Company had 99 employees as of December 31, 2000, none of who are currently represented by a union. The Company considers itself to have good relations with its employees. The Company employs eight petroleum engineers and seven petroleum geoscientists.

FEDERAL REGULATIONS

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

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

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

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

SALES AND TRANSPORTATION OF CRUDE OIL. Sales of crude oil and condensate can be made by the Company at market prices not subject at this time to price controls. The price that the Company receives from the sale of these products will be affected by the cost of transporting the products to market. The rates, terms, and conditions applicable to the interstate transportation of oil and related products by pipelines are regulated by the FERC under the Interstate Commerce Act. As required by the Energy Policy Act of 1992, the FERC has revised its regulations governing the rates that may be charged by oil pipelines. The new rules, which were effective January 1, 1995, provide a simplified, generally applicable method of regulating such rates by use of an index for setting rate ceilings. The FERC will also, under defined circumstances, permit alternative ratemaking methodologies for interstate oil pipelines such as the use of cost of service rates, settlement rates,

and market-based rates. Market-based rates will be permitted to the extent the pipeline can demonstrate that it lacks significant market power in the market in which it proposes to charge market-based rates. The cumulative effect that these rules may have on moving the Company's production to market cannot yet be determined.

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

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

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

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

The Mineral Leasing Act of 1920 ("Mineral Act") prohibits direct or indirect ownership of any interest in federal onshore oil and gas leases by a foreign citizen of a country that denies "similar or like privileges" to citizens of the

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

STATE REGULATIONS

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

The Company may enter into agreements relating to the construction or operation of a pipeline system for the transportation of natural gas. To the extent that such gas is produced, transported and consumed wholly within one state, such operations may, in certain instances, be subject to the jurisdiction of such state's administrative authority charged with the responsibility of regulating intrastate pipelines. In such event, the rates which the Company could charge for gas, the transportation of gas, and the costs of construction and operation of such pipeline would be impacted by the rules and regulations governing such matters, if any, of such administrative authority. Further, such a pipeline system would be subject to various state and/or federal pipeline safety regulations and requirements, including those of, among others, the Department of Transportation. Such regulations can increase the cost of planning, designing, 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 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

The Company is engaged in the exploration, development, acquisition and production of oil and gas properties and natural gas transmission and provides oil and gas property management services for other investors. The Company's 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, 2000, the Company's estimated net proved reserves totaled 33.4 million barrels of oil ("MBbl") and 133.4 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 $939.3 million. Gas constitutes approximately 40% of the Company's total estimated proved reserves and approximately 20% of the Company's 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 for the Company's twelve largest fields and for all other properties combined at December 31, 2000.

<TABLE>
<CAPTION>

PROVED RESERVES AND PRODUCTION BY FOCUS AREA:	PRIMARY OPERATOR	2000 PRODUCTION (MMcfe)	ESTIMATED NET PROVED RESERVES OIL (MBbls)	ESTIMATED NET PROVED RESERVES GAS (MMcf)	ESTIMATED NET PROVED RESERVES TOTAL (MMcfe)	PRE-TAX DISCOUNTED PRESENT VALUE ($000)
		(b)	(b)	(a)(b)		
<S>	<C>	<C>	<C>	<C>	<C>	<C>
GULF OF MEXICO SHELF:						
Mobile Block 864 Area	Callon	5,474	--	47,582	47,582	$264,436
Main Pass Block 26 SL 15827	Callon	385	116	2,855	3,551	20,248
South Marsh Island 261	Callon	1,960	962	2,995	8,767	18,920
East Cameron Block 275	Callon	1,185	13	2,616	2,694	17,766
High Island Block A-494 "Snapper"	Petrosec	668	--	1,637	1,637	10,852
Main Pass 163 Area	Callon	1,317	--	2,431	2,431	10,404
Chandeleur Block 40	Callon	399	--	1,470	1,470	9,758
Other	Various	2,166	79	2,537	3,011	15,294
TOTAL SHELF AREA		13,554	1,170	64,123	71,143	367,678
GULF OF MEXICO DEEPWATER:						
Garden Banks Blocks 738/782/826/827 "Entrada"	BP Amoco	--	7,983	29,940	77,838	191,234
Mississippi Canyon 538/582 "Medusa"	Murphy	--	9,585	9,288	66,798	130,982
Garden Banks Block 341 "Habanero"	Shell	--	6,393	12,547	50,905	112,967

Ewing Bank Block 994 "Boomslang"	Murphy	--	7,230	13,015	56,395	102,206
TOTAL DEEPWATER AREA		--	31,191	64,790	251,936	537,389
ONSHORE AND OTHER:						
Big Escambia Creek	Exxon	421	639	1,523	5,357	12,304
Other	Various	1,359	382	2,967	5,259	21,954
TOTAL ONSHORE AND OTHER		1,780	1,021	4,490	10,616	34,258
TOTAL PROVED RESERVES		15,334	33,382	133,403	333,695	$939,325

</TABLE>

- ----------------
(a) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated net proved reserves as of December 31, 2000, 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 3.5 Bcf and $29.5 million of pre-tax discounted present value and 2,300 MMcf of 2000 production 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. Callon owns a 20% working interest in this discovery with BP Amoco holding the remaining working interest.

The operator is evaluating information obtained in a data swap with another exploration company that has announced a similar discovery adjacent to Entrada and is incorporating it into the Entrada development plans.

Medusa, Mississippi Canyon Block 538/582

The initial well encountered two intervals with over 120 feet of total pay after being drilled to a measured depth of 16,241 feet. The test well encountered 59 true vertical feet of pay in the T1 objective in Fault Block A and 61 true vertical feet of pay in the T4 sand. A sidetrack well, testing the extent of the discovery, encountered 110 true vertical feet of pay in the T1 objective sand in Fault Block B. An additional sidetrack well was drilled to test the downdip limits of the T1 pay sand in Fault Block B and encountered 90 feet (true vertical depth) of oil pay. A delineation well was drilled in January 2000, and

tested the updip limits of the T1 pay sand in Fault Block A. This latest well was drilled deeper to further delineate the T4 objective, which was discovered by the original well. Medusa lies in approximately 2,100 feet of water and the Company owns a 15% working interest with Murphy, the operator owning 60% and British-Borneo Petroleum, Inc. owning the remaining 25%.

The operator has submitted an Authorization For Expenditure for a floating production system at Medusa and the integrated project team has been active on this development project since late third quarter of 2000. The drilling of four development wells and the completion of one existing wellbore are scheduled to begin in April 2001. This will provide five initial takepoints for the production facility. First production is anticipated in late 2002 or early 2003.

Habanero, Garden Banks Block 341

During February 1999 the initial test well on the Company's 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 the second deepwater success for Callon. Callon owns 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 including sidetracking the existing well with two additional sidetracks is scheduled to begin by midyear 2001. 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, Callon 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 Callon's total working interest in the well to 55%.

A complete field study has been initiated with a goal of generating a delineation and development proposal in 2001. Prior to designing production facilities for Boomslang the Company plans to drill the Sidewinder prospect, located immediately to the southeast of Boomslang on Ewing Bank Block 995 and Green Canyon Blocks 24 and 25. Callon owns a 15% working interest in these 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. The Company consummated five acquisitions in this area for a total of $63.8 million. In total, the Company has 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. The Company was appointed operator of the Mobile Block 864 unit and three other wells. Net average daily production during 2000 was 15 MMcf per day.

South Marsh Island Block 261

In November 1999, we announced a discovery on this block, which encountered 110 feet of net natural gas pay. We began drilling a second test well in December 1999 and encountered 100 feet of net natural gas pay in five pay sands before it blew out. We brought the well under control, plugged it and drilled a replacement well in the first quarter of 2000. Our insurance policy covered the costs associated with the blowout, the plugging of the well and the drilling of the replacement well. The #1 well commenced production in May 2000 and was shut-in during January 2001 after depleting. An evaluation of new seismic indicated the productive sand is compartmentalized by faulting and the well is currently scheduled for sidetrack drilling to a separate fault block. The #3 well commenced production in May 2000. Upon depletion, the well is scheduled to be recompleted in a behind pipe oil sand. We drilled a fourth well in the second quarter of 2000 and encountered 165 net feet of pay in four pay sands. The fourth well commenced production on February 10, 2001. We own a 100% working interest in these wells.

East Cameron Block 275

In December 1999, we announced a discovery, which encountered net natural gas pay of 160 feet in five intervals between 5,800 feet and 10,500 feet. The well commenced production in April 2000. The well was recompleted in October 2000 and subsequently shut-in for work on the host production platform. The well came back online January 12, 2001. We own a 100% working 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. The well depleted this productive zone in January 2001 and was recompleted to a behind pipe gas zone in February 2001. We operate this well.

Snapper, High Island Block A-494

In January 1999, we announced a discovery on our Snapper prospect, which we drilled to a total depth of 8,800 feet. We own a 50% working interest in this well, which is operated by PetroQuest Energy. The well began production in July 1999.

ONSHORE

We own various small royalty and working interests in several onshore areas, which as of December 31, 2000 had total net proved reserves of 10.6 Bcfe with a discounted present value of $34.2 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.

OIL AND GAS RESERVES

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

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	2000(a)	1999(a)	1998
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Proved developed:			
Oil (Bbls)	2,192	1,376	2,079
Gas (Mcf)	67,463	82,109	76,895
Proved undeveloped:			
Oil (Bbls)	31,190	22,458	4,819
Gas (Mcf)	65,940	34,326	11,135
Total proved:			
Oil (Bbls)	33,382	23,834	6,898
Gas (Mcf)	133,403	116,435	88,030
Estimated pre-tax future net cash flows	$1,610,320	$528,659	$152,552
Pre-tax discounted present value	$ 939,325	$296,513	$99,751
Standardized measure of discounted future net cash flows	$ 671,197	$256,322	$99,751

</TABLE>

(a) The estimates include 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 and 3.5 Bcf, $31.8 million of pre- tax future net cash flows and $29.5 million of pre-tax discounted present value flows in 2000 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.

The Company's 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 the 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 the control of the Company and 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.

The Company has 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 drilled and completed by the Company during the periods indicated. All such wells were drilled in the continental United States including federal and state waters in the Gulf of Mexico.

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,					
	2000		1999		1998	
	GROSS	NET	GROSS	NET	GROSS	NET
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Development:						
Oil	2	.35	--	--	2	.40
Gas	--	--	--	--	--	--
Non-productive	--	--	--	--	--	--
Total	2	.35	--	--	2	.40
Exploration:						
Oil	1	.20	2	0.26	1	.35
Gas	2	2.00	5	3.79	3	2.14
Non-productive	6	2.29	2	1.20	2	1.25
Total	9	4.49	9	5.25	6	3.74

</TABLE>

The Company owned working and royalty interests in approximately 254 gross (7.0 net) producing oil and 289 gross (30.0 net) producing gas wells as of December 31, 2000. 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 the Company's wells produce both oil and gas. At December 31, 2000, the Company had one gross (0.1 net) exploratory oil well in progress.

LEASEHOLD ACREAGE

The following table shows the approximate developed and undeveloped (gross and net) leasehold acreage of the Company as of December 31, 2000.

<TABLE>
<CAPTION>
LEASEHOLD ACREAGE

LOCATION	DEVELOPED GROSS	DEVELOPED NET	UNDEVELOPED GROSS	UNDEVELOPED NET
Alabama	13,394	13,246	256	29
Louisiana	8,925	6,309	2,375	700
Other States	912	440	1,471	1,142
Federal Waters	135,612	88,071	356,990	112,322
Total	158,843	108,066	361,092	114,193

As of December 31, 2000, the Company owned various royalty and overriding royalty interests in 1,336 net developed acres and 6,862 undeveloped acres. In addition, the Company owned 6,247 developed and 119,753 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, 2000	1999	1998
Adams Resources Marketing, Ltd.	14%	16%	--
Columbia Energy Services	--	29%	22%
Dynegy Marketing & Trade	--	12%	23%
PG&E Energy Trading Corporation	--	--	26%
Reliant Energy Services	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

The Company believes that the title to its 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 the opinion of the Company, are not so material as to detract substantially from the use or value of such properties. The Company's 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 the Company or its 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 the Company's rights to production revenues, they have been taken into account in calculating the Company's net revenue interests and

in estimating the size and value of the Company's reserves. The Company believes that the burdens and obligations affecting its properties are conventional in the industry for properties of the kind owned by the Company.

ITEM 3. LEGAL PROCEEDINGS

The Company is a defendant in various legal proceedings and claims, which arise in the ordinary course of Callon's business. Callon does not believe the ultimate resolution of any such actions will have a material affect on the Company's 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 2000.

PART II.

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

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

<TABLE>
<CAPTION>

	QUARTER ENDED	HIGH	LOW
1999:			
	First quarter	$ 11.875	$ 8.875
	Second quarter	11.250	9.875
	Third quarter	15.375	10.000
	Fourth quarter	15.375	11.625
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

</TABLE>

As of March 16, 2001, there were approximately 5,283 common stockholders of record.

The Company has not paid dividends on the Common Stock and intends to retain its cash flow from operations, net of preferred stock dividends, for the future operation and development of its business. In addition, the Company's primary credit facility and the terms of the Company's outstanding subordinated debt restrict payments of dividends on its Common Stock.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information for the Company. The financial information for each of the five years in the period ended December 31, 2000 have been derived from the audited Consolidated Financial Statements of the Company 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 future results for the Company.

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

<TABLE>
<CAPTION>

YEARS ENDED DECEMBER 31,

	2000	1999	1998	1997	1996
<S>	<C>	<C>	<C>	<C>	<C>
STATEMENT OF OPERATIONS DATA:					
Revenues:					
Oil and gas sales	$ 56,310	$ 37,140	$ 35,624	$ 42,130	$ 25,764
Interest and other	1,767	1,853	2,094	1,508	946
Total revenues	58,077	38,993	37,718	43,638	26,710
Costs and expenses:					
Lease operating expenses	9,339	7,536	7,817	8,123	7,562
Depreciation, depletion and amortization	17,153	16,727	19,284	16,488	9,832
General and administrative	4,155	4,575	5,285	4,433	3,495
Interest	8,420	6,175	1,925	1,957	313
Accelerated vesting and retirement benefits	--	--	5,761	--	--
Impairment of oil and gas properties	--	--	43,500	--	--
Total costs and expenses	39,067	35,013	83,572	31,001	21,202
Income (loss) from operations	19,010	3,980	(45,854)	12,637	5,508
Income tax expense (benefit)	6,463	1,353	(15,100)	4,200	50
Net income (loss)	12,547	2,627	(30,754)	8,437	5,458
Preferred stock dividends	2,403	2,497	2,779	2,795	2,795
Net income (loss) available to common shares	$ 10,144	$ 130	$ (33,533)	$ 5,642	$ 2,663
Net income (loss) per common share:					
Basic	$ .82	$ .01	$ (4.17)	$ .91	$ .46
Diluted	$ .80	$ .01	$ (4.17)	$ .88	$ .45
Shares used in computing net income (loss) per common share:					
Basic	12,420	8,976	8,034	6,194	5,835
Diluted	12,745	9,075	8,034	6,422	5,952
BALANCE SHEET DATA (END OF PERIOD):					
Oil and gas properties, net	$ 258,613	$ 194,365	$ 141,905	$ 150,494	$ 82,489
Total assets	$ 301,569	$ 259,877	$ 181,652	$ 190,421	$ 118,520
Long-term debt, less current portion	$ 134,000	$ 100,250	$ 78,250	$ 60,250	$ 24,250
Stockholders' equity	$ 136,328	$ 124,380	$ 84,484	$ 113,701	$ 77,864

</TABLE>

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We use the full-cost method of accounting. Under this method of accounting, our net capitalized costs to acquire, explore and develop oil and gas properties may not exceed the standardized measure of our proved reserves. If these capitalized costs exceed the standardized measure, 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 ($28.7 million after-tax) 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 the Company's financial condition and results of operations. The Company's 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. The Company's revenues, profitability and future growth and the carrying value of its oil and gas properties are substantially dependent on prevailing prices of oil and gas and its ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. The Company's ability to maintain or increase its 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 increased significantly at December 31, 2000 to 334 billion cubic feet of natural gas equivalent (Bcfe). This represents an increase of 28% over previous year-end 1999 estimated proved reserves of 259 Bcfe. This increase in 2000 is primarily due to results of drilling activity in the deepwater areas of the Gulf of Mexico, along with drilling successes on the Gulf of Mexico Shelf area.

These reserve estimates include 3.5 Bcfe at December 31, 2000 and 5.8 Bcfe at December 31, 1999 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 the control of the Company. 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 the Company's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. The Company uses 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 its future production and does not use them for trading purposes. On a Mcfe basis, natural gas represents 86% of the budgeted 2001 production and 40% of proved reserves at year-end.

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

LIQUIDITY AND CAPITAL RESOURCES

The Company's primary sources of capital are its cash flows from operations, borrowings under our bank Credit Facility and sales of debt and equity securities. Net cash and cash equivalents decreased during 2000 by $22.8 million. Cash provided from operating activities during 2000 totaled $28.7 million. The Company completed the sale of its Senior Subordinated Notes due 2005 in October 2000 for net proceeds of approximately $31.5 million. An additional $24.9 million (net) was borrowed under our bank Credit Facility. Dividends paid on preferred stock were $2.2 million. Average debt outstanding was $118.3 million during 2000 compared to $96.9 million in 1999. At December 31, 2000, the Company had working capital of $1.1 million.

Effective October 31, 2000, the Company entered into a $75.0 million Credit Facility with First Union National Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of the Company's producing oil and gas properties 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 the Company's proved producing oil and gas reserves as determined by the bank. The Company may borrow, pay, reborrow and repay under the Credit Facility until July 31, 2002, on which date, the Company must repay in full all amounts then outstanding. At December 31, 2000, availability under the Credit Facility was $25 million.

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

The Company completed the sale of $33 million Senior Subordinated Notes due 2005, on October 26, 2000 for net proceeds of $31.5 million from the offering after deducting the underwriters' discount and offering expenses. Approximately $20.8 million of the net proceeds from the offering were used to purchase the

Company's outstanding 10% Senior Subordinated Notes due 2001 in conjunction with a tender offer. The Company also redeemed the remaining $3.4 million of its 10% Senior Subordinated Notes due 2001 not tendered in the offer.

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. The Company is in compliance with these covenants at December 31, 2000.

In November of 1999, the Company sold 3,680,000 shares of Common Stock in a public offering at a price to the public of $11.875 per share. Cash proceeds received by the Company were $41.1 million net of underwriting discount and offering costs. The proceeds from the stock offering were used to pay the outstanding balance of the Company's Credit Facility and to fund, together with internally generated cash flows from operations, the remaining portion of the Company's 1999 and part of the 2000 capital expenditure budget.

The Company's plans for 2001 include capital expenditures budgeted at $90 million. The Company currently expects to spend $21 million to drill up to 14 wells in the shelf area of the Gulf of Mexico. An estimated $18 million, net to the Company, will be required to complete and develop the successful wells. This estimate is dependent on exploration success. Plans also call for $36 million to be invested in the deepwater area of the Gulf of Mexico with $18 million of the investment allocated to development of the Company's four deepwater discoveries. The Company will continue to build its portfolio of drilling prospects and is budgeted to spend approximately $9 million on seismic and new Gulf of Mexico lease acquisitions.

Projected cash flows from operations, cash on hand and borrowings under the Credit Facility are anticipated to be sufficient to fund the Company's shelf drilling program and seismic and lease acquisitions. Conventional debt or equity offerings may be used to finance the Company's capital expenditure program, but other options are being considered for the Company's deepwater development projects. One such option is to develop a discovery as a production hub, with some or all of the financing provided by a partner, and charge other companies with discoveries in the area for access to the processing equipment on the platform.

RESULTS OF OPERATIONS

The following table sets forth certain operating information with respect to the oil and gas operations of the Company for each of the three years in the period ended December 31, 2000.

<TABLE>
<CAPTION>

	DECEMBER 31,		
	2000(a)(b)	1999(a)(b)	1998(a)
<S>	<C>	<C>	<C>
Production:			
Oil (MBbls)	232	330	310
Gas (MMcf)	13,943	14,606	14,036
Total production (MMcfe)	15,334	16,589	15,894
Average daily production (MMcfe)	41.9	45.5	43.5
Average sales price:			
Oil (per Bbl)	$ 27.88	$ 12.16	$ 12.41
Gas (per Mcf)	$ 3.57	$ 2.27	$ 2.26
Total production (per Mcfe)	$ 3.67	$ 2.24	$ 2.24
Average costs (per Mcfe):			
Lease operating expenses (excluding severance taxes)	$ .55	$ .39	$ .44
Severance taxes	$ .06	$ .07	$ .06
Depletion	$ 1.10	$ .99	$ 1.19
General and administrative (net of management fees)	$ .27	$ .28	$ .33

</TABLE>

\- ------------

(a) Includes hedging gains and losses

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

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 a combination of an increase in the amortization base by 56% (primarily 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 capitalized 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

The Company's 2000 results include a deferred income tax expense of $6.5 million. The Company has 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. The Company believes 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, 1999 AND 1998

OIL AND GAS REVENUES

Oil and gas revenues for 1999 were $37.1 million, a 4% increase from the 1998 amount of $35.6 million. Similarly, 1999 oil and gas production of 16,589 MMcfe increased by 4% over the 1998 amount of 15,894 MMcfe.

Oil production increased from 310,000 barrels in 1998 to 330,000 barrels in 1999 but the average sales price declined from $12.41 in 1998 to $12.16 in 1999. As a result, oil revenues went from $3.8 million in 1998 to $4.0 million in 1999. The increase in oil production was primarily from Main Pass 26 and Eugene Island 335 offset by the loss of production in 1999 from the Black Bay Field, which was sold in 1998.

Gas revenues for 1999 were $33.1 million based on sales of 14.6 Bcf at an average sales price of $2.27 per Mcf. For 1998, gas revenues were $31.8 million based on production of 14 Bcf sold at an average sales price of $2.26 per Mcf. When compared to 1998, the Company in 1999 added gas production from new discoveries at Main Pass 26 and Eugene Island 335 but has experienced reduced production from several Shallow Miocene properties, which normally have steep decline curves. Except for the increase at Main Pass 31, which was the result of a recompletion, other properties continue to experience normal and expected declines.

LEASE OPERATING EXPENSES AND SEVERANCE TAXES

Lease operating expenses, including severance taxes, decreased from $7.8 million in 1998 to $7.5 million in 1999 as a result of a decrease in operating expenses in the Main Pass 163 Area and the North Dauphin Island Field as well as the sale of the Black Bay Field in 1998. This decline was offset by the Snapper, Main Pass 36, Main Pass 26 and Kemah properties, which began operations in 1999.

DEPRECIATION, DEPLETION AND AMORTIZATION

Depreciation, depletion and amortization decreased due to the combined effect of the net increase in proved reserves during 1999 (primarily in the fourth quarter of 1999), the level of finding costs attributable to reserves added in 1999 and the reduction of the full cost pool due to an impairment of oil and gas properties at December 31, 1998. Total charges decreased from $19.3 million, or $1.21 per Mcfe in 1998, to $16.7 million, or $1.01 per Mcfe in 1999.

GENERAL AND ADMINISTRATIVE

General and administrative expenses for 1999 were $4.6 million, or $.28 per Mcfe, compared to $5.3 million, or $.33 per Mcfe, in 1998. This 13% decrease is primarily due to a reduction of staff in 1999 along with an increase in overhead allocable to employees directly engaged in the acquisition, exploration and development of oil and gas properties in 1999.

INTEREST EXPENSE

Interest expense for 1999 and 1998 was $6.2 million and $1.9 million, respectively. This increase is a result of a decrease in interest capitalized on unevaluated oil and gas properties and the increase in interest rates and in average debt outstanding in 1999 versus 1998. This average debt outstanding increase is directly related to the Senior Subordinated Notes issued in July 1999 and the Credit Facility borrowings during the year. The Common Stock offering completed in November 1999 reduced Credit Facility debt at the end of 1999.

INCOME TAXES

The Company's 1999 results include a deferred income tax expense of $1.4 million. The Company has 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. The Company believes 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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

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

As of December 31, 2000, the Company had open collar contracts with third parties whereby minimum floor prices and maximum ceiling prices are contracted and applied to related contract volumes. These agreements in effect for 2001 are for average gas volumes of 390,000 Mcf per month beginning in January 2001 through October 2001 at (on average) a ceiling price of $5.86 and floor price of $4.69. The Company had no open oil hedging contracts at December 31, 2000.

The calculation of the fair market value of the outstanding hedging contracts as of December 31, 2000 indicated a $5.8 million market value liability based on market prices at that date. Natural gas prices have declined significantly since year-end. As a result, and if the price decline for natural gas is sustained throughout the contract periods, the market value liability of the derivatives described above have decreased significantly also.

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 Company adopted SFAS 133 effective January 1, 2001.

This statement establishes accounting and reporting standards that differ from those used in prior years. SFAS 133 requires that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value at the date of adoption and requires that future changes in the derivatives fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative instrument's gain or loss to offset related results on the hedged item in the income statement, to the extent effective, and requires that the Company must formally document, designate, and assess effectiveness of transactions that receive hedge accounting. The Company believes that its hedges described above, to the extent of intrinsic value, will qualify as cash flow hedges under SFAS 133.

The Company has not yet quantified all effects of adopting SFAS 133 on its future financial statements. However, the Statement will increase volatility in earnings and other comprehensive income as market prices for the natural gas hedged changes.

Based on projected annual sales volumes for 2001 (excluding forecast production increases over 2000), a 10% decline in the prices the Company receives for its crude oil and natural gas production would have an approximate $7.1 million impact on the Company's revenues. The hypothetical impact on the decline in oil and gas prices does not include the incremental gain that would be realized upon a decline in prices by the oil and gas hedging contracts in place as of December 31, 2000.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

<TABLE>
<CAPTION>

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, 2000 and 1999, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. 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, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

New Orleans, Louisiana,
February 22, 2001

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

<TABLE>
<CAPTION>

	DECEMBER 31, 2000	DECEMBER 31, 1999
ASSETS		
<S>	<C>	<C>
Current assets:		
Cash and cash equivalents	$ 11,876	$ 34,671
Accounts receivable	9,244	5,362
Advance to operators	1,131	--
Other current assets	207	189
Total current assets	22,458	40,222
Oil and gas properties, full-cost accounting method:		
Evaluated properties	589,549	511,689
Less accumulated depreciation, depletion and amortization	(378,589)	(361,758)
	210,960	149,931
Unevaluated properties excluded from amortization	47,653	44,434
Total oil and gas properties	258,613	194,365
Pipeline and other facilities, net	5,537	5,860
Other property and equipment, net	1,790	1,450
Deferred tax asset	8,573	14,995
Long-term gas balancing receivable	643	243
Other assets, net	3,955	2,742
Total assets	$ 301,569	$ 259,877
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 17,842	$ 16,786
Undistributed oil and gas revenues	1,411	2,082
Accrued net profits interest payable	2,146	1,676
Total current liabilities	21,399	20,544
Long-term debt	134,000	100,250
Deferred revenue on sale of production payment	7,236	12,080
Accrued retirement benefits	1,886	2,107
Long-term gas balancing payable	720	516
Total liabilities	165,241	135,497
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, 2000 and 1,045,461 outstanding at December 31, 1999 with a liquidation		

preference of $15,021,525 at December 31, 2000	6	11
Common Stock, $.01 par value; 20,000,000 shares authorized; 13,327,675 and 12,239,238 shares outstanding at December 31, 2000 and 1999, respectively	133	122
Treasury stock (99,078 shares at cost)	(1,183)	(1,183)
Capital in excess of par value	151,223	149,425
Retained earnings (deficit)	(13,851)	(23,995)
Total stockholders' equity	136,328	124,380
Total liabilities and stockholders' equity	$ 301,569	$ 259,877

</TABLE>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)

<TABLE>
<CAPTION>

<S>	2000 <C>	1999 <C>	1998 <C>
Revenues:			
Oil and gas sales	$ 56,310	$ 37,140	$ 35,624
Interest and other	1,767	1,853	2,094
Total revenues	58,077	38,993	37,718
Costs and expenses:			
Lease operating expenses	9,339	7,536	7,817
Depreciation, depletion and amortization	17,153	16,727	19,284
General and administrative	4,155	4,575	5,285
Interest	8,420	6,175	1,925
Accelerated vesting and retirement benefits	--	--	5,761
Impairment of oil and gas properties	--	--	43,500
Total costs and expenses	39,067	35,013	83,572
Income (loss) from operations	19,010	3,980	(45,854)
Income tax expense (benefit)	6,463	1,353	(15,100)
Net income (loss)	12,547	2,627	(30,754)
Preferred stock dividends	2,403	2,497	2,779
Net income (loss) available to common shares	$ 10,144	$ 130	$ (33,533)

Net income (loss) per common share:

Basic	$ .82	$ .01	$ (4.17)
	============	============	============
Diluted	$ .80	$ .01	$ (4.17)
	============	============	============
Shares used in computing net income (loss) per common share:			
Basic	12,420	8,976	8,034
	============	============	============
Diluted	12,745	9,075	8,034
	============	============	============

</TABLE>

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

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

<TABLE>
<CAPTION>

	PREFERRED STOCK	COMMON STOCK	TREASURY STOCK	UNEARNED COMPENSATION RESTRICTED STOCK	CAPITAL IN EXCESS OF PAR VALUE	RETAINED EARNINGS (DEFICIT)
	----------	----------	----------	-------------	-----------	----------
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Balances, December 31, 1997	$ 13	$ 79	$ --	$ (2,232)	$ 106,433	$ 9,408
Net income (loss)	--	--	--	--	--	(30,754)
Preferred stock dividends	--	--	--	--	15	(2,779)
Shares issued pursuant to employee benefit and option plan	--	--	--	--	235	--
Employee stock purchase plan	--	--	--	--	163	--
Restricted stock plan	--	2	--	(2,731)	2,584	--
Earned portion of restricted stock	--	--	--	4,963	--	--
Conversion of preferred shares to common	--	1	--	--	(1)	--
Stock buyback plan	--	--	(915)	--	--	--
	----------	----------	----------	----------	----------	----------
Balances, December 31, 1998	13	82	(915)	--	109,429	(24,125)
Net income (loss)	--	--	--	--	--	2,627
Sale of common stock	--	37	--	--	40,994	--
Preferred stock dividends	--	--	--	--	--	(2,222)
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	(2)	5	--	--	274	(275)
Stock buyback plan	--	--	(268)	--	--	--
	----------	----------	----------	----------	----------	----------
Balances, December 31, 1999	11	122	(1,183)	--	149,425	(23,995)
Net income (loss)	--	--	--	--	--	12,547
Preferred stock dividends	--	--	--	--	--	(1,978)
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	(425)

Balances, December 31, 2000	$ 6	$ 133	$ (1,183)	$ --	$ 151,223	$ (13,851)

</TABLE>

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

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2000, 1999 AND 1998
(IN THOUSANDS)

<TABLE>
<CAPTION>

	2000	1999	1998
Cash flows from operating activities:			
Net income (loss)	$ 12,547	$ 2,627	$ (30,754)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	17,598	17,232	19,791
Impairment of oil and gas properties	--	--	43,500
Amortization of deferred costs	1,034	707	619
Amortization of deferred production payment revenue	(4,844)	(2,710)	--
Deferred income tax expense (benefit)	6,463	1,353	(15,100)
Noncash charge related to compensation plans	1,069	275	7,583
Changes in current assets and liabilities:			
Accounts receivable	(3,882)	662	6,144
Advance to operators	(1,131)	1,271	(1,271)
Other current assets	(18)	(11)	57
Current liabilities	1,077	1,981	(876)
Change in gas balancing receivable	(400)	(44)	43
Change in gas balancing payable	204	27	85
Change in other long-term liabilities	(221)	(216)	--
Change in other assets, net	(751)	(134)	(116)
Cash provided (used) by operating activities	28,745	23,020	29,705
Cash flows from investing activities:			
Capital expenditures	(81,849)	(51,709)	(63,501)
Cash proceeds from sale of mineral interests	--	--	9,909
Cash provided (used) by investing activities	(81,849)	(51,709)	(53,592)
Cash flows from financing activities:			
Equity issued related to employee stock plans	269	68	414
Purchase of treasury shares	--	(268)	(915)
Payment on debt	(29,250)	(42,500)	--
Increase in debt	63,000	64,500	18,000
Deferred financing costs	(1,496)	(1,823)	--
Restricted stock plan	--	(1,615)	(130)
Sale of common stock	--	41,031	--
Cash dividends on preferred stock	(2,214)	(2,333)	(2,779)

Cash provided (used) by financing activities	30,309	57,060	14,590
Net increase (decrease) in cash and cash equivalents	(22,795)	28,371	(9,297)
Cash and cash equivalents:			
Balance, beginning of period	34,671	6,300	15,597
Balance, end of period	$ 11,876	$ 34,671	$ 6,300

</TABLE>

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

CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

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

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

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION AND REPORTING

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

USE OF ESTIMATES

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

ACCOUNTING PRONOUNCEMENTS

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133 ("SFAS 133"), Accounting for Derivative Instruments and Hedging Activities. The Statement establishes accounting and reporting standards requiring that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 is effective for fiscal years beginning after June 15, 2000, with earlier application permitted. The Company adopted SFAS 133 effective January 1, 2001.

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

PROPERTY AND EQUIPMENT

The Company follows the full-cost method of accounting for oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves, including certain overhead costs, are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases and other costs related to exploration and development activities. Payroll and general and administrative costs capitalized include salaries and related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs do not include any costs related to production or 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 management determines these costs have been impaired.

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

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using geological, engineering and regulatory data available. Such cost estimates are periodically updated for changes in conditions and requirements. Such estimated amounts are considered as part of the full cost pool subject to amortization upon acquisition or discovery. Such costs are capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities take place.

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

NATURAL GAS IMBALANCES

The Company follows an entitlement method of accounting for its proportionate share of gas production on a well-by-well basis, recording a receivable to the extent that a well is in an "undertake" position and conversely recording a liability to the extent that a well is in an "overtake" position.

DERIVATIVES

The Company uses derivative financial instruments for price protection purposes on a limited amount of its future production and does not use them for trading purposes. Such derivatives were accounted for in years prior to and including 2000 as hedges and have been recognized as an adjustment to oil and gas sales in the period in which they are related. Future accounting treatment will be under SFAS 133 (see Note 6).

ACCOUNTS RECEIVABLE

Accounts receivable consists primarily of accrued oil and gas production receivables. The balance in the reserve for doubtful accounts included in accounts receivable was $78,000 and $38,000 at December 31, 2000 and 1999, respectively. Net recoveries were $40,000 in 2000. There were no provisions to expense in the three-year period ended December 31, 2000.

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:

<TABLE>
<CAPTION>

	DECEMBER 31,		
	2000	1999	1998
<S>	<C>	<C>	<C>
Adams Resources Marketing, Ltd.	14%	16%	--
Columbia Energy Services	--	29%	22%
Dynegy Marketing & Trade	--	12%	23%
PG&E Energy Trading Corporation	--	--	26%
Reliant Energy Services	37%	--	--
Unocal Exploration Corporation	8%	--	--

</TABLE>

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

STATEMENTS OF CASH FLOWS

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

The Company paid no federal income taxes for the three years ended December 31, 2000. During the years ended December 31, 2000, 1999 and 1998, the Company made cash payments of $11,449,000, $9,013,000 and $6,229,000 respectively, for interest.

PER SHARE AMOUNTS

Basic income or loss per common share were computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the year. Diluted income per common share for 2000 and 1999 were determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options considered common stock equivalents computed using

the treasury stock method. In 1998, all options were excluded from the computation of diluted loss per share because they were antidilutive. The conversion of the preferred stock was not included in any annual calculation due to its antidilutive effect on diluted income or loss per common share.

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

<TABLE>
<CAPTION>

<S>	2000 <C>	1999 <C>	1998 <C>
(a) Net income (loss) available for common stock	$ 10,144	$ 130	$ (33,533)
Preferred dividends assuming conversion of preferred stock (if dilutive)	--	--	--
(b) Income available for common stock assuming conversion of preferred stock (if dilutive)	$ 10,144	$ 130	$ (33,533)
(c) Weighted average shares outstanding	12,420	8,976	8,034
Dilutive impact of stock options	325	99	--
Convertible preferred stock (if dilutive)	--	--	--
(d) Total diluted shares	12,745	9,075	8,034
Stock options excluded due to antidilutive impact	--	--	163
Basic income (loss) per share (a/c)	$ .82	$ .01	$ (4.17)
Diluted income (loss) per share (b/d)	$ .80	$ .01	$ (4.17)

</TABLE>

FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair value of cash, cash equivalents, accounts receivable, accounts payable and long-term debt approximates book value at December 31, 2000 and 1999. Fair value of long-term debt (specifically, the 10%, the 10.125%, the 10.25% and the 11% Senior Subordinated Notes) was based on quoted market value.

The calculation of the fair market value of the outstanding hedging contracts (see Note 6) as of December 31, 2000 indicated a $5.8 million market value liability based on market prices at that date. See Note 6 for further discussion related to the derivative activity of the Company.

3. INCOME TAXES

The Company follows the asset and liability method of accounting for deferred income taxes prescribed by Statement of Financial Accounting Standards No. 109 ("SFAS 109") "Accounting for Income Taxes". The statement provides for the recognition of a deferred tax asset for deductible temporary timing differences, capital and operating loss carryforwards, statutory depletion carryforward and tax credit carryforwards, net of a "valuation allowance". The valuation allowance is provided for that portion of the asset, for which it is deemed more likely than not, that it will not be realized. The Company's management determined that no valuation allowance was required in 2000 and 1999. Accordingly, the Company has recorded a deferred tax asset at December 31, 2000 and 1999 as follows:

<TABLE>
<CAPTION>

<S>	DECEMBER 31, 2000 (IN THOUSANDS) <C>	DECEMBER 31, 1999 <C>
Federal net operating loss carryforwards	$ 14,352	$ 13,143
Statutory depletion carryforward	4,152	4,087
Temporary differences:		
Oil and gas properties	(8,937)	(2,200)
Pipeline and other facilities	(1,938)	(2,051)
Non-oil and gas property	(81)	(102)
Other	1,025	2,118
Total tax asset	8,573	14,995
Valuation allowance	--	--
Net tax asset	$ 8,573	$ 14,995

</TABLE>

At December 31, 2000, the Company had, for federal tax reporting purposes, net operating loss carryforwards of $41.0 million, which expire in 2001 through 2015. Additionally, the Company had available for tax reporting purposes $11.9 million in statutory depletion deductions, which can be carried forward for an indefinite period.

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

The provision for income taxes at the Company's effective tax rate differed from the provision for income taxes at the statutory rate as follows:

	2000	1999	1998
	(IN THOUSANDS)		
Computed expense (benefit) at the expected statutory rate	$ 6,463	$ 1,353	$ (15,590)
Other	--	--	490
Deferred income tax expense (benefit)	$ 6,463	$ 1,353	$ (15,100)

4. SALE OF PRODUCTION PAYMENT INTEREST

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

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	DECEMBER 31, 2000	DECEMBER 31, 1999
	(IN THOUSANDS)	
Credit Facility	$ 25,000	$ 100
10% Senior Subordinated Notes	--	24,150
10.125% Senior Subordinated Notes (due 2002)	36,000	36,000
10.25% Senior Subordinated Notes (due 2004)	40,000	40,000
11% Senior Subordinated Notes (due 2005)	33,000	--
	134,000	100,250

Less: current portion	--	--
	$ 134,000	$ 100,250

</TABLE>

The Company negotiated a new Credit Facility effective October 31, 2000 with First Union National Bank. Borrowings under the Credit Facility are secured by mortgages covering substantially all of the Company's producing oil and gas properties. Currently, the Credit Facility is for $75 million with an initial $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 the Company's proved producing oil and gas reserves. Pursuant to the Credit Facility, the interest rate is equal to the lender's prime rate plus 0.25%. The Company, at its option, may fix the interest rate on all or a portion of the outstanding principal balance at 1.75% above a defined "Eurodollar" rate for periods up to six months. The weighted average interest rate for the Credit Facility debt outstanding at December 31, 2000 and 1999 was 8.53% and 9.00%, respectively. Under the Credit Facility, a commitment fee of 0.25% or 0.375% per annum, depending on the amount of the unused portion of the borrowing base, is payable quarterly. The Company may borrow, pay, reborrow and repay under the Credit Facility until July 31, 2002 up to the borrowing base amount, on which date, the Company must repay in full all amounts then outstanding.

On July 31, 1997, the Company issued $36 million of its 10.125% Series A Senior Subordinated Notes due September 15, 2002. Interest on the 10.125% Notes is payable quarterly, on March 15, June 15, September 15, and December 15 of each year. The 10.125% Notes are redeemable at the option of the Company in whole or in part, at any time on or after September 15, 2000. The 10.125% Notes are general unsecured obligations of the Company, subordinated in right of payment to all existing and future indebtedness of the Company.

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

of control clause that obligates the Company to repurchase the notes for 101% of par should a change of control occur. Interest is paid quarterly.

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

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. The Company is in compliance with these covenants at December 31, 2000.

6. HEDGING CONTRACTS

The Company periodically uses derivative financial instruments to manage oil and gas price risk. Settlements of gains and losses on commodity price contracts are generally based upon the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price, and are reported in 2000 and prior years as a component of oil and gas revenues. Gains or losses attributable to the termination of a contract are deferred and recognized in revenue when the oil and gas production is sold. Approximately $3,290,000 and $1,559,000 were recognized as a reduction of oil and gas revenue in 2000 and 1999 respectively, and $1,886,000 was recognized as additional oil and gas revenue in 1998 as a result of such agreements.

As of December 31, 2000, the Company had open collar contracts with third parties whereby minimum floor prices and maximum ceiling prices are contracted and applied to related contract volumes. These agreements in effect for 2001 are for average gas volumes of 390,000 Mcf per month beginning in January 2001 through October 2001 at (based on a weighted average of the contracts) a ceiling price of $5.86 and floor price of $4.69. The Company had no open oil hedging contracts at December 31, 2000.

As discussed in Note 2, the Company adopted SFAS 133 effective January 1, 2001. This statement establishes accounting and reporting standards that differ from those used in prior years. SFAS 133 requires that every derivative instrument be recorded in the balance sheet as either an asset or liability measured at its fair value at the date of adoption. The statement requires that future changes in the derivatives fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative instrument's gain or loss to offset related results on the hedged item in the income statement, to the extent effective, and requires that the Company must formally document, designate, and assess effectiveness of transactions that receive hedge accounting. The Company believes that its hedges described above, to the extent of intrinsic value, will qualify as cash flow hedges under SFAS 133.

The Company has not yet quantified all effects of adopting SFAS 133 on its future financial statements. However as discussed in the following paragraphs, the Statement will increase volatility in earnings and other comprehensive income.

The Company will record a market value liability in 2001 of $5.8 million related to the fair value of the derivatives outstanding at January 1, 2001 with a corresponding charge, net of tax, to other comprehensive income. This transition adjustment will be reclassified into earnings in the same period or periods during which the hedged forecasted transactions affects earnings, adjusted for any future changes in fair value.

Oil and gas prices have declined significantly since January 1, 2001(the date of the transition entry to record the derivatives at fair value) causing substantially all of the liability recorded on the balance sheet at that date to be reversed in the first quarter of 2001.

7. COMMITMENTS AND CONTINGENCIES

As described in Note 9, abandonment trusts (the "Trusts") have been established for future abandonment obligations of those oil and gas properties of the Company burdened by a net profits interest. The management of the Company believes the Trusts will be sufficient to offset those future abandonment liabilities; however, the Company is responsible for any abandonment expenses in excess of the Trusts' balances. As of December 31, 2000 total estimated site restoration, dismantlement and abandonment costs were approximately $6,227,000, net of expected salvage value. Substantially all such costs are expected to be funded through the Trusts' funds, all of which will be accessible to the Company when abandonment work begins. In addition, as a working interest owner and/or operator of oil and gas properties, the Company is responsible for the cost of abandonment of such properties. See Note 2.

The Company, as part of the Consolidation, entered into Registration Rights Agreements whereby the former stockholders of certain of the Constituent Entities are entitled to require the Company to register Common Stock of the Company owned by them with the Securities and Exchange Commission for sale to the public in a firm commitment public offering and generally to include shares owned by them, at no cost, in registration statements filed by the Company. Costs of the offering will not include discounts and commissions, which will be paid by the respective sellers of the Common Stock.

8. OIL AND GAS PROPERTIES

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

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	2000	1999	1998
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 511,689	$ 444,579	$ 398,046
Property acquisition costs	3,211	24,153	9,464
Exploration costs	51,837	37,427	42,617
Development costs	25,242	5,530	4,361
Sale of mineral interests	(2,430)	--	(9,909)
End of period balance	$ 589,549	$ 511,689	$ 444,579
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 44,434	$ 42,679	$ 35,339
Additions	4,381	4,890	11,156
Capitalized interest	4,548	3,497	4,440
General and administrative costs	5,036	3,623	4,515
Transfers to evaluated	(10,746)	(10,255)	(12,771)
End of period balance	$ 47,653	$ 44,434	$ 42,679
Accumulated depreciation, depletion and amortization			
Beginning of period balance	$ 361,758	$ 345,353	$ 282,891
Provision charged to expense	16,831	16,405	18,962
Impairment of oil and gas properties	--	--	43,500
End of period balance	$ 378,589	$ 361,758	$ 345,353

</TABLE>

Unevaluated property costs, primarily lease acquisition costs incurred at federal lease sales, unevaluated drilling costs, capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base consisted of $12.3 million incurred in 2000, $7.5 million incurred in 1999 and $27.9 million incurred in 1998 and prior. These costs are directly related to the acquisition and evaluation of unproved properties and major development projects. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The majority of these costs will be evaluated over the next five-year period.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $1.10, $.99 and $1.19 for the years ended December 31, 2000, 1999, and 1998, respectively.

IMPAIRMENT OF OIL AND GAS PROPERTIES-1998

Under full-cost accounting rules, the capitalized costs of proved oil and gas properties are subject to a "ceiling test", which limits such costs to the estimated present value net of related tax effects, discounted at a 10 percent interest rate, of future net cash flows from proved reserves, based on current economic and operating conditions (PV10). If capitalized costs exceed this limit, the excess is charged to expense. During the fourth quarter of 1998, the Company recorded a noncash impairment provision related to oil and gas properties in the amount of $43.5 million ($28.7 million after-tax) primarily due to the significant decline in oil and gas prices at December 31, 1998.

9. NET PROFITS INTEREST

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

The Company has, pursuant to the purchase agreements, created abandonment trusts whereby funds are provided out of gross production proceeds from the properties for the estimated amount of future abandonment obligations related to the working interests owned by the Company. The Trusts are administered by unrelated third party trustees for the benefit of the Company's working interest in each property. The Trust agreements limit their funds to be disbursed for the satisfaction of abandonment obligations. Any funds remaining in the Trusts after all restoration, dismantlement and abandonment obligations have been met will be distributed to the owners of the properties in the same ratio as contributions to the Trusts. The Trusts' assets are excluded from the Consolidated Balance Sheets of the Company because the Company does not control the Trusts. Estimated future revenues and costs associated with the NPI and the Trusts are also excluded from the oil and gas reserve disclosures at Note 12. As of December 31, 2000 and 1999, the Trusts' assets (all cash and investments) totaled $6,227,000 and $5,690,000 respectively, all of which will be available to the Company to pay its portion, as working interest owner, of the restoration, dismantlement and abandonment costs discussed at Note 7.

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

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

10. EMPLOYEE BENEFIT PLANS

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

- The Savings and Protection Plan provides employees with the option to defer receipt of a portion of their compensation and the Company may, at its discretion, match a portion of the employee's deferral with cash and Company Common Stock. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the Savings and Protection Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested, including Company discretionary contributions, immediately upon participation in the Savings and Protection Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $500,000, $466,000, and $468,000 in the years 2000, 1999 and 1998, respectively.

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

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

- - The Company granted 533,000 stock options to employees on March 23, 2000 and 120,000 stock options to directors on July 25, 2000 at $10.50 per share. The March 23, 2000 grant was subject to shareholder approval of an amendment to the 1996 Stock Incentive Plan. The amendment, which was approved on May 9, 2000 at the Annual Meeting of Shareholders, increased the number of shares reserved for issuance under the 1996 plan. The excess of the market price over the exercise price on the approval date of the amendment is amortized over the three-year vesting period of the options. Compensation costs of $800,973 were recognized in income in 2000 related to these options.

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

<TABLE>
<CAPTION>

		2000	1999	1998
		(IN THOUSANDS, EXCEPT PER SHARE DATA)		
<S>		<C>	<C>	<C>
Net income (loss) available for common shares:	As Reported	$ 10,144	$ 130	$ (33,533)
	Pro Forma	8,418	(1,212)	(34,421)
Basic earnings (loss) per share:	As Reported	.82	.01	(4.17)
	Pro Forma	.68	(.14)	(4.28)
Diluted earnings (loss) per share:	As Reported	.80	.01	(4.17)
	Pro Forma	.66	(.14)	(4.28)

</TABLE>

A summary of the status of the Company's two stock option plans at December 31, 2000, 1999 and 1998 and changes during the years then ended is presented in the table and narrative below:

<TABLE>
<CAPTION>

	2000		1999		1998	
	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE	SHARES	WTD AVG EX PRICE
<S>	<C>	<C>	<C>	<C>	<C>	<C>
Outstanding, beginning of year	1,536,500	$ 10.60	1,266,000	$ 11.00	1,041,000	$ 11.19
Granted (at market)	135,000	14.73	270,500	9.27	225,000	10.08
Granted (below market)	653,000	10.50	--	--	--	--
Exercised	(20,333)	9.00	--	--	--	--
Forfeited	--	--	--	--	--	--
Expired	--	--	--	--	--	--
Outstanding, end of year	2,304,167	$ 10.83	1,536,500	$ 10.60	1,266,000	$ 11.00
Exercisable, end of year	1,647,657	$ 10.71	1,247,600	$ 10.47	802,250	$ 10.90
Weighted average fair value of options granted (at market)	$ 7.68		$ 4.94		$ 4.31	
Weighted average fair value of options granted (below market)	$ 7.90		N/A		N/A	

</TABLE>

At December 31, 2000, 2,129,167 of the 2,304,167 options outstanding have exercise prices between $9 and $13.50 with a weighted average exercise price of $10.51 and a weighted average remaining contractual life of 6.85 years. Of these options, 1,546,357 are exercisable at a weighted average exercise price of $10.46. The remaining 175,000 options have exercise prices between $13.50 and $15.31 with a weighted average exercise price of $14.69 and a weighted average remaining contractual life of 8.98 years. Of these options, 101,300 are exercisable at a weighted average exercise price of $14.46.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used for options granted during 2000, 1999 and 1998.

<TABLE>
<CAPTION>

	2000	1999	1998
<S>	<C>	<C>	<C>
Risk free interest rate	6.3%	6.3%	5.1%
Expected life (years)	5.0	7.0	7.0
Expected volatility	52.1%	46.0%	28.8%
Expected dividends	--	--	--

</TABLE>

The Company awarded 225,000 performance shares under the 1996 Plan to the Company's Executive officers on August 23, 1996. All of the performance shares granted were scheduled to vest in whole on January 1, 2001. The unearned portion was being amortized as compensation expense on a straight-line basis over the vesting period. An additional 25,000 shares were issued under the 1994 Plan in 1997 and 165,500 shares were issued to certain key employees other than the Company's Executive officers in 1998.

Approximately $4,963,000 in 1998 and $714,000 in 1997 of compensation cost were charged to expense related to the restricted shares granted. In December 1998, the Company approved the accelerated vesting of all performance shares. As a result, an additional charge of $3,469,000 which represents the future unamortized expense related to unvested shares at the date the acceleration of vesting occurred, was expensed in 1998.

In addition, the Company recorded a provision of approximately $2.3 million for retirement benefits approved by the compensation committee of the Board of Directors in December of 1998.

11. EQUITY TRANSACTIONS

In November 1995, the Company sold 1,315,500 shares of $2.125 Convertible Exchangeable Preferred Stock, Series A (the "Preferred Stock") for net proceeds of $30.9 million. Annual dividends are $2.125 per share and are cumulative. The net proceeds of the $.01 par value stock after underwriters discount and expense was $30,899,000. Each share has a liquidation preference of $25.00, plus accrued and unpaid dividends. Dividends on the Preferred Stock are cumulative from the date of issuance and are payable quarterly, commencing January 15, 1996. The Preferred Stock is convertible at any time, at the option of the holders thereof, unless previously redeemed, into shares of Common Stock of the Company at an initial conversion price of $11 per share of Common Stock, subject to adjustments under certain conditions.

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

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

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

The Company adopted a stockholder rights plan on March 30, 2000, designed to assure that the Company's stockholders receive fair and equal treatment in the event of any proposed takeover of the Company and to guard against partial tender offers, squeeze-outs, open market accumulations, and other abusive tactics to gain control without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, the Company declared a dividend of one right ("Right")

on each share of the Company's Common Stock. Each Right will entitle the holder to purchase one one-thousandth of a share of a Series B Preferred Stock, par value $0.01 per share, at an exercise price of $90 per one one-thousandth of a share. The Rights are not currently exercisable and will become exercisable only in the event a person or group acquires, or engages in a tender or exchange offer to acquire, beneficial ownership of 15 percent or more (one existing stockholder was granted an exception for up to 21 percent) of the Company's Common Stock. After the Rights become exercisable, each Right will also entitle its holder to purchase a number of common shares of the Company having a market value of twice the exercise price. The dividend distribution was made to stockholders of record at the close of business on April 10, 2000. The Rights will expire on March 30, 2010.

12. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company's proved oil and gas reserves at December 31, 2000, 1999 and 1998 have been estimated by independent petroleum consultants in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

The 2000 estimates have been adjusted (per SEC guidelines) to exclude (i) volumes (approximately 3.5 billion cubic feet of natural gas) and (ii) future revenues of approximately $31.8 million associated with the volumetric production payment described in Note 4. The adjustments resulted in a reduction of approximately $29.5 million in standardized measure of discounted net cash flows, before tax, associated with this volumetric production payment.

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

ESTIMATED RESERVES

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

RESERVE QUANTITIES

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	2000	1999	1998
<S>	<C>	<C>	<C>
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	23,834	6,898	3,402
Revisions to previous estimates	85	(686)	(99)
Purchase of reserves in place	--	2,629	162
Sales of reserves in place	--	--	(1,531)
Extensions and discoveries	9,695	15,323	5,274
Production	(232)	(330)	(310)
End of period	33,382	23,834	6,898
Natural Gas (MMcf):			
Beginning of period	110,621	88,030	88,738
Revisions to previous estimates	(4,817)	(11,492)	(8,631)
Purchase of reserves in place	347	4,733	4,414
Sales of reserves in place	--	--	(684)
Extensions and discoveries	35,387	42,662	18,229
Production	(11,616)	(13,312)	(14,036)
End of period	129,922	110,621	88,030

Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	1,376	1,774	2,976
End of period	2,192	1,376	1,774
Natural Gas (MMcf):			
Beginning of period	76,295	76,895	88,010
End of period	63,982	76,295	76,895

</TABLE>

STANDARDIZED MEASURE

The following tables present the Company's standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves and were computed using reserve valuations based on regulations prescribed by the SEC. These regulations provide that the oil, condensate and gas price structure utilized to project future net cash flows reflects current prices ($9.14 for natural gas and $26.71 for oil for the 2000 disclosures) at each date presented and have been escalated only when known and determinable price changes are provided by contract and law. Future production, development and net abandonment costs are based on current costs without escalation. The resulting net future cash flows have been discounted to their present values based on a 10% annual discount factor.

STANDARDIZED MEASURE

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	2000	1999	1998
	(IN THOUSANDS)		
<S>	<C>	<C>	<C>
Future cash inflows	$ 2,080,680	$ 847,930	$ 256,325
Future costs -			
Production	(284,667)	(207,615)	(67,192)
Development and net abandonment	(217,507)	(123,749)	(36,581)
Future net inflows before income taxes	1,578,506	516,567	152,552
Future income taxes	(472,637)	(109,238)	--
Future net cash flows	1,105,869	407,329	152,552
10% discount factor	(434,672)	(151,007)	(52,801)
Standardized measure of discounted future net cash flows	$ 671,197	$ 256,322	$ 99,751

</TABLE>

CHANGES IN STANDARDIZED MEASURE

<TABLE>
<CAPTION>

	YEARS ENDED DECEMBER 31,		
	2000	1999	1998

(IN THOUSANDS)			
<S>	<C>	<C>	<C>
Standardized measure - beginning of period	$ 256,322	$ 99,751	$ 128,079
Sales and transfers, net of production costs	(42,132)	(27,076)	(27,807)
Net change in sales and transfer prices, Net of production costs	361,179	57,246	(33,029)
Exchange and sale of in place reserves	--	--	(4,445)
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs	276,770	181,185	24,294
Revisions of quantity estimates	(12,399)	(22,438)	(9,409)
Accretion of discount	28,581	9,975	13,645
Net change in income taxes	(209,090)	(29,492)	7,926
Changes in production rates, timing and other	11,966	(12,829)	497
Standardized measure - end of period	$ 671,197	$ 256,322	$ 99,751

</TABLE>

13. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

<TABLE>
<CAPTION>

(IN THOUSANDS, EXCEPT PER SHARE DATA)	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
<S>	<C>	<C>	<C>	<C>
2000				
Total revenues	$ 10,118	$ 14,716	$ 16,422	$ 16,821
Total costs and expenses	8,354	9,935	9,958	10,820
Income tax expense	600	1,626	2,197	2,040
Net income	1,164	3,155	4,267	3,961
Net income per share-basic	0.05	0.21	0.30	0.25
Net income per share-diluted	0.05	0.21	0.29	0.24
1999				
Total revenues	$ 8,374	$ 9,031	$ 10,584	$ 11,004
Total costs and expenses	7,659	8,690	8,986	9,678
Income tax expense	243	116	543	451
Net income	472	225	1,055	875
Net income (loss) per share-basic	(0.04)	(0.04)	0.06	0.03
Net income (loss) per share-diluted	(0.04)	(0.04)	0.06	0.03

</TABLE>

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

None.

PART III.

ITEMS 10, 11, 12 &13

For information concerning Item 10 - Directors and Executive Officers of the Registrant, Item 11 - Executive Compensation, Item 12 - Security Ownership of Certain Beneficial Owners and Management and Item 13 - Certain Relationships and Related Transactions, see the definitive Proxy Statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders on May 4, 2001 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. The following is an index to the financial statements and financial statement schedules that are filed as part of this Form 10-K on pages 32 through 53.

Report of Independent Public Accountants

Consolidated Balance Sheets as of the Years Ended December 31, 2000 and 1999

Consolidated Statements of Operations for the Three Years in the Period Ended December 31, 2000

Consolidated Statements of Stockholders' Equity for the Three Years in the Period Ended December 31, 2000

Consolidated Statements of Cash Flows for the Three Years in the Period Ended December 31, 2000

Notes to Consolidated Financial Statements

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

(a) 3. Exhibits:

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

3. Articles of Incorporation and Bylaws

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

   3.2 Certificate of Merger of Callon Consolidated Partners, L. P. with and into the Company dated September 16, 1994 (incorporated by reference from Exhibit 3.2 of the Company's Report on Form 10-K for the fiscal year ended December 31, 1994)

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

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

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

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

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

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

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

4.6 Form of Note Indenture for the Company's 10.25% Senior Subordinated Notes due 2004 (incorporated by reference from Exhibit 4.10 of the Company's Registration Statement on Form S-2, filed June 25, 1999, Reg. No. 333-80579)

4.7 Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 4 of the Company's 8-K filed April 6, 2000)

4.8 Subordinated Indenture for the Company dated October 26, 2000 (incorporated by reference from Exhibit 4.1 of the Company's Current Report on Form 8-K dated October 24, 2000)

4.9 Supplemental Indenture for the Company's 11% Senior Subordinated Notes due 2005 (incorporated by reference from Exhibit 4.2 of the Company's Current Report on Form 8-K dated October 24, 2000)

9. Voting trust agreement

None.

10. Material contracts

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

10.2 Counterpart to Registration Rights Agreement by and between the Company, Ganger Rolf ASA and Bonheur ASA.

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

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

10.5 Consulting Agreement between the Company and John S. Callon dated June 19, 1996 (incorporated by reference from Exhibit

10.10 of the Company's Registration Statement on Form S-1, filed November 5, 1996, Reg. No. 333-15501)

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

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

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

10.9 Credit Agreement dated as of October 30, 2000 between the Company and First Union National Bank, as administrative agent for the lenders (incorporated by reference from Exhibit 10.2 of the Company's September 30, 2000 Form 10-Q filed November 13, 2000)

11. Statement re computation of per share earnings*

12. Statements re computation of ratios*

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

16. Letter re change in certifying accountant*

18. Letter re change in accounting principles*

21. Subsidiaries of the Company

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

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

23. Consents of experts and counsel

23.1 Consent of Arthur Andersen LLP

24. Power of attorney*

99. Additional Exhibits*

- ----------

*Inapplicable to this filing.

(b) Reports on Form 8-K.

The Company filed a Report on Form 8-K on October 27, 2000 under "Item 5 - Other Events" filing certain exhibits in connection with the offer and sale of the Company's 11% Senior Subordinated Notes due 2005.

The Company filed a Report on Form 8-K on December 4, 2000 under "Item 5 - Other Events" which contained the news release regarding the completion of the redemption of its 10% Senior Subordinated Notes due 2001.

SIGNATURES

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

CALLON PETROLEUM COMPANY

Date: March 30, 2001	/s/ Fred L. Callon Fred L. Callon (principal executive officer, director)
Date: March 30, 2001	/s/ John S. Weatherly John S. Weatherly (principal financial officer)
Date: March 30, 2001	/s/ James O. Bassi James O. Bassi (principal accounting officer)
Date: March 30, 2001	/s/ John S. Callon John S. Callon (director)
Date: March 30, 2001	/s/ Dennis W. Christian Dennis W. Christian (director)
Date: March 30, 2001	/s/ B. F. Weatherly B. F. Weatherly (director)
Date: March 30, 2001	/s/ John C. Wallace John C. Wallace (director)

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

CALLON PETROLEUM COMPANY

Date: March 30, 2001	By: /s/ John S. Weatherly John S. Weatherly, Senior Vice President and Chief Financial Officer

INDEX TO EXHIBITS

<TABLE>
<CAPTION>

EXHIBIT

NUMBER   DESCRIPTION
- ------   -----------

<S>   <C>

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</TABLE>

<TABLE>
<S> <C>
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99. Additional Exhibits*
</TABLE>

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

Exhibit 10.2

COUNTERPART TO REGISTRATION RIGHTS AGREEMENT

BY AND BETWEEN CALLON PETROLEUM COMPANY

(FORMERLY CALLON PETROLEUM HOLDING COMPANY)

AND NOCO ENTERPRISES, L.P.

DATED SEPTEMBER 16, 1994

WHEREAS, the parties have caused this Counterpart to be executed and delivered by their respective duly authorized officers for purposes of Section 7.3 of the above-mentioned Registration Rights Agreement and for purposes of confirming that the 1,839,836 shares of the common stock of Callon Petroleum Company to be acquired jointly by Ganger Rolf ASA and Bonheur ASA directly from Fred. Olsen Energy ASA are "Registrable Securities" as defined in the Registration Rights Agreement; and

WHEREAS, Ganger Rolf ASA and Bonheur ASA agree to be bound by the terms of the Registration Rights Agreement;

IN WITNESS WHEREOF, this Counterpart is effective as of the 28th day of August, 2000.

CALLON PETROLEUM COMPANY

By: /s/ Robert A. Mayfield

Name: Robert A. Mayfield

Title: Corporate Secretary

GANGER ROLF ASA

By:	/s/ F. Haavardsson	/s/ J. C. Wallace
Name:	F. Haavardsson	J. C. Wallace
Title:	Director	Director

BONHEUR ASA

By:	/s/ F. Haavardsson	/s/ J. C. Wallace
Name:	F. Haavardsson	J. C. Wallace
Title:	Director	Director

Exhibit 23.1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation by reference of our report dated February 22, 2001, included in this Form 10-K, into Callon Petroleum Company's previously filed Registration Statements on Forms S-8 (File Nos. 33-90410, 333-29537, 333-29529 and 333-47784).

Arthur Andersen LLP

March 29, 2001
New Orleans, Louisiana