CALLON PETROLEUM CO
Form 10-K
March 15, 2006

Table of Contents

UNITED STATES 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, 2005
Commission File Number 001-14039
CALLON PETROLEUM COMPANY
(Exact name of Registrant as specified in its charter)

Delaware	**64-0844345**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi 39120	**(601) 442-1601**
(Address of Principal Executive Offices)(Zip Code)	(Registrant s telephone number including area code)

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

Title of each class	**Name of exchange on which registered**
Common Stock, Par Value $.01 Per Share	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No þ

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 þ No o

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definitions of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o Accelerated filer þ Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2). Yes o No þ

The aggregate market value of the voting and non-voting common equity held by nonaffiliates of the registrant was approximately $270.9 million as of June 30, 2005 (based on the last reported sale price of such stock on the New York Stock Exchange on such date of $14.78).

As of March 2, 2006, there were 19,373,193 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, 2005) relating to the Annual Meeting of Stockholders to be held on May 4, 2006, which are incorporated into Part III of this Form 10-K.

TABLE OF CONTENTS

Table of Contents

PART I.

ITEM 1 and 2. BUSINESS and PROPERTIES

Overview

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

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

Over the past 10 years, we have placed emphasis on the acquisition of acreage with exploration and development drilling opportunities in the Gulf of Mexico shelf and deepwater areas. At December 31, 2005, we owned working interests in a total of 88 blocks/leases covering 152,000 net acres. To minimize risk we join with industry partners to explore federal offshore blocks acquired in the Gulf of Mexico. We perform extensive geological and geophysical studies using computer-aided exploration techniques (CAEX), including, where appropriate, the acquisition of 3-D seismic or high-resolution 2-D data to facilitate these efforts. We continue to develop prospects on the shelf through our 3-D seismic partnership using Amplitude versus Offset (AVO) technology. In 1998, we began exploration in the Gulf of Mexico deepwater area (generally 900 to 5,500 feet of water) and during the fourth quarter of 2003, our first two deepwater projects, the Medusa and Habanero fields, began production. Please see Significant Properties for a more detailed discussion.

We ended the year 2005 with estimated net proved reserves of 188.6 billion cubic feet of natural gas equivalent (Bcfe). This represents a decrease of 1% from 2004 year-end estimated net proved reserves of 191.1 Bcfe. We produced 18.8 million cubic feet of natural gas equivalent (Mmcfe) and had net reserve additions of 16.3 Mmcfe. The major focus of our future operations is expected to continue to be the exploration for and development of oil and gas properties, primarily in the Gulf of Mexico.

Availability of Reports

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

Table of Contents

Business Strategy

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

- focus on Gulf of Mexico exploration with a balance between shelf and deepwater areas using the latest available technology;
- aggressively explore our existing prospect inventory; and
- replenish our prospect inventory with increasing emphasis on prospect generation using AVO technology.

Exploration and Development Activities

In 2005, capital expenditures for exploration and development costs related to oil and gas properties totaled approximately $90 million, of which $17 million was included in accounts payable at December 31, 2005. We incurred approximately:

- $34 million in the Gulf of Mexico shelf and onshore south Louisiana areas which included the drilling of 11 exploratory wells, four of which were unsuccessful;
- $16 million for completion and development costs associated with our successful drill wells, two of which came online in 2005 and the remaining are scheduled to come online in the first half of 2006;
- $5 million in our deepwater area, which includes the development and completion costs for North Medusa;
- $15 million for leasehold and seismic costs;
- $7 million for the acquisition of producing oil and gas properties and miscellaneous costs; and
- $6 million for capitalized interest and $7 million for capitalized general and administration costs allocable directly to exploration and development projects.

Risk Factors

A decrease in oil and gas prices may adversely affect our results of operations and financial condition. Our success is highly dependent on prices for oil and gas, which are extremely volatile. Any substantial or extended decline in the price of oil or gas would have a material adverse effect on us. Oil and gas markets are both seasonal and cyclical. The prices of oil and gas depend on factors we cannot control such as weather, economic conditions, and levels of production, actions by OPEC and other countries and government actions. Prices of oil and gas will affect the following aspects of our business:

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

Table of Contents

Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this annual report.

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

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

Also, under MMS rules governing our deepwater Medusa property and several of our shallow water, deep natural gas properties and prospects, we are eligible for royalty suspensions depending on the difference between the average monthly New York Mercantile Exchange (NYMEX) sales price for oil or gas and price thresholds set by the MMS. As a result, our reserve estimates may increase or decrease depending upon the relation of price thresholds versus the average NYMEX prices.

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

On December 31, 2005, approximately 58% of the discounted present value of our estimated net proved reserves were proved undeveloped. Proved undeveloped reserves represented 60% of total proved reserves. Most of these proved undeveloped reserves were attributable to our deepwater properties. Development of these properties is subject to additional risks as described above.

Table of Contents

Information about reserves constitutes forward-looking information. See Forward-Looking Statements for information regarding forward-looking information.

Unless we are able to replace reserves which we have produced, our cash flows and production will decrease over time. Our future success depends upon our ability to find, develop and acquire oil and gas reserves that are economically recoverable. As is generally the case for Gulf properties, our producing properties usually have high initial production rates, followed by a steep decline in production. As a result, we must continually locate and develop or acquire new oil and gas reserves to replace those being depleted by production. We must do this even during periods of low oil and gas prices when it is difficult to raise the capital necessary to finance these activities and during periods of high operating costs when it is expensive to contract for drilling rigs and other equipment and personnel necessary to explore for oil and gas. Without successful exploration or acquisition activities, our reserves, production and revenues will decline rapidly. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

Also, because of the aggregate 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 2005, 86% of our daily production came from five of our properties in the Gulf of Mexico. Moreover, one property accounted for 43% of our production during this period. In addition, at December 31, 2005, most of our proved reserves were located in three fields in the Gulf of Mexico, with approximately 76% of our total net proved reserves attributable to these properties. If mechanical problems, storms or other events curtailed a substantial portion of this production or if the actual reserves associated with any one of these producing properties are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

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

- 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.

Table of Contents

We do not operate all of our properties and have limited influence over the operations of some of these properties, particularly our deepwater properties. Our lack of control could result in the following:

- the operator may initiate exploration or development at 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 non-operated properties.

Our deepwater operations have special operational risks that may negatively affect the value of those assets. Drilling operations in the deepwater area are by their nature more difficult and costly than drilling operations in shallow water. Deepwater drilling operations require the application of more advanced drilling technologies involving a higher risk of technological failure and usually have significantly higher drilling costs than shallow water drilling operations. Deepwater wells are completed using sub-sea completion techniques that require substantial time and the use of advanced remote installation equipment. These operations involve a high risk of mechanical difficulties and equipment failures that could result in significant cost overruns.

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

- decisions made by the operators of our deepwater wells;
- the availability of materials necessary to construct the facilities;
- the proximity of our discoveries to pipelines; and
- the price of oil and natural gas.

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

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

Table of Contents

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

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

Our competitors may use superior technology, which we may be unable to afford or which would require costly investment by us in order to compete. Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected. For example, marine seismic acquisition technology has been characterized by rapid technological advancements in recent years, and further significant technological developments could substantially impair our 3-D seismic data s value.

We may not be able to replace our reserves or generate cash flows if we are unable to raise capital. We will be required to make substantial capital expenditures to develop our existing reserves, and to discover new oil and gas reserves. Historically, we have financed these expenditures primarily with cash from operations, proceeds from bank borrowings and proceeds from the sale of debt and equity securities. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources for a discussion of our capital budget. We cannot assure you that we will be able to raise capital in the future. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially.

We expect to continue using our senior secured credit facility to borrow funds to supplement our available cash. The amount we may borrow under our senior secured credit facility may not exceed a borrowing base determined by the lenders under such facility based on their projections of our future production, 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 secured credit facility exceed the borrowing base, the lenders may require that we repay the excess. If this were to occur, we might have to sell assets or seek financing from other sources. Sales of assets could further reduce the amount of our borrowing base. We cannot assure you that we would be successful in selling assets or arranging substitute financing. If we were not able to repay borrowings under our senior secured credit facility to reduce the outstanding amount to less than the borrowing base, we would be in default under our senior secured credit facility. For a description of our senior secured credit facility and its principal terms and conditions, see

Table of Contents

Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and Note 5 to our Consolidated Financial Statements.

Our decision to drill a prospect is subject to a number of factors and we may decide to alter our drilling schedule or not drill at all. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect which will require substantial additional seismic data processing and interpretation. Whether we ultimately drill a prospect may depend on the following factors:

- receipt of additional seismic data or the reprocessing of existing data;
- material changes in oil or gas prices;
- the costs and availability of drilling rigs;
- the success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of the costs to drill or complete wells;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks; and
- decisions of our joint working interest owners.

We will continue to gather data about our prospects and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all. You should understand that our plans regarding our prospects are subject to change.

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;
- 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; and
- because of these or other events, we could experience environmental hazards, including oil spills, gas leaks, and ruptures.

In the event of any of the foregoing, we may be subject to interrupted production or substantial environmental liability due to injury to or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damage, investigation and remediation requirements. Moreover, a substantial portion of our operations are offshore and are subject to a variety of risks peculiar to the marine environment such as capsizing, collisions, hurricanes and other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Offshore operations are also subject to more extensive governmental regulation. We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

Table of Contents

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. We also enter into price collars to reduce the risk of changes in oil and gas prices. Under a collar, no payments are due by either party so long as the market price is above a floor set in the collar and below a ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to us and if the price is above the ceiling, we pay the counter-party the difference. Another type of hedging contract we have entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to us. See Quantitative and Qualitative Disclosures About Market Risks for a discussion of our hedging practices.

Compliance with environmental and other government regulations could be costly and could negatively impact production. Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of the material regulations applicable to us, see Regulations . These laws and regulations may:

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

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

Table of Contents

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

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected. Our management, including our Chief Executive and Financial Officer, does not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Table of Contents

Forward-Looking Statements

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

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

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

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

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

Corporate Offices

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

Table of Contents

Employees

We had 87 employees as of December 31, 2005, none of whom are currently represented by a union. We believe that we have good relations with our employees. We employ five petroleum engineers and seven petroleum geoscientists.

Regulations

General. The oil and gas industry is subject to regulation at the federal, state and local level, and some of the laws, rules and regulations that govern our operations carry substantial penalties for non-compliance. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

- the location of wells,
- the method of drilling and completing wells,
- the rate of production,
- the surface use and restoration of properties upon which wells are drilled,
- the plugging and abandoning of wells,
- the disposal of fluids used or other wastes obtained in connection with operations,
- the marketing, transportation and reporting of production, and
- the valuation and payment of royalties.

For instance, our OCS leases in federal waters are administered by the Minerals Management Service, or MMS, and require compliance with detailed MMS regulations and orders. Lessees must obtain MMS approval for exploration plans and exploitation and production plans prior to the commencement of such operations. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and prohibiting the flaring of liquid hydrocarbons and oil without prior authorization. MMS policies concerning the volume of production that a lessee must have to maintain an offshore lease beyond its primary term also are applicable to Callon. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of all production facilities. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees have substantial net worth or post bonds or other acceptable assurances that such obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial conditions and results of operations.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Table of Contents

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position. Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

Environmental Regulation. Various federal, state and local laws and regulations concerning the discharge of contaminants into the environment, the generation, storage, transportation and disposal of contaminants, and the protection of public health, natural resources, wildlife and the environment affect our exploration, development and production operations, including processing facilities. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, constructing, operating and abandoning wells. In most instances, the regulatory requirements relate to the handling and disposal of drilling and production waste products, water and air pollution control procedures, and the remediation of petroleum-product contamination. In addition, our operations may require us to obtain permits for, among other things,

- air emissions,
- discharges into surface waters, and
- the construction and operations of underground injection wells or surface pits to dispose of produced saltwater and other nonhazardous oilfield wastes.

In the event of an unauthorized discharge, emission or activity, we may be liable for penalties, costs and damages. Under state and federal laws, we could be required to remove or remediate previously disposed wastes and remediate contamination, including contamination in surface water, soil or groundwater, caused by disposal of that waste. We could be responsible for wastes disposed of or released by us or prior owners or operators at properties owned or leased by us or at locations where wastes have been taken for disposal. We could also be required to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination. The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and nonhazardous wastes. The owner and operator of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of a hazardous substance into the environment. The Environmental Protection Agency, state environmental agencies and, in some cases, third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such action. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary business costs in the oil and gas industry. Although we are not fully

Table of Contents

insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Callon. We believe we are in compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Commitments and Contingencies

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

Property Summary

We are engaged in the exploration, development, acquisition and production of oil and gas properties. Our properties are concentrated offshore in the Gulf of Mexico and onshore, primarily, in Louisiana and Alabama. We have historically increased our reserves and production by focusing primarily on low to moderate risk exploration and acquisition opportunities in the Gulf of Mexico shelf area. In 1998, we expanded our area of exploration to include the Gulf of Mexico deepwater area. As of December 31, 2005, our estimated net proved reserves totaled 188.6 Bcfe and included 18.4 million barrels of oil (MMBbl) and 78.0 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 of $1.1 billion. Oil constitutes approximately 59% on an equivalent basis of our total estimated proved reserves and approximately 40% of our total estimated proved reserves are proved developed reserves.

Our Medusa (Mississippi Canyon Blocks 538/582) and Habanero (Garden Banks Block 341) discoveries began production in the fourth quarter of 2003. A detailed discussion of each of these properties is provided in the Significant Properties section of this report. These two deepwater discoveries were responsible for 62% of our total production during 2005.

Table of Contents

Significant Properties

The following table shows discounted cash flows and estimated net proved oil and gas reserves by major field and for all other properties combined at December 31, 2005.

		Estimated Net Proved Reserves			Pre-tax Discounted Present Value ($000) (a)(b)
	Operator	Oil (MBbls)	Gas (MMcf)	Total (MMcfe)	
Gulf of Mexico Deepwater:					
Garden Banks Block 738/782/826/827 Entrada	BP	7,772	29,126	75,760	$ 409,904
Mississippi Canyon 538/582 Medusa	Murphy	6,566	4,814	44,208	255,386
Garden Banks Block 341 Habanero	Shell	2,886	6,730	24,047	150,678
Gulf of Mexico Shelf:					
West Cameron Block 295	HydroGOM/Cimarex		8,217	8,217	58,401
High Island Block A-540	Walter	106	3,305	3,939	24,127
Mobile Blocks 953/955	Callon		4,216	4,216	24,201
Mobile Block 864 Unit	Callon		3,517	3,517	19,008
North Padre Island Block 913	Callon	2	3,457	3,467	29,381
East Cameron Block 90	Callon		2,255	2,256	19,487
High Island Block 119	Kerr-McGee	25	1,822	1,970	14,803
Other	Various	70	4,107	4,530	19,319
Onshore and Other:					
Alabama	Various	513	1,288	4,365	18,121
Louisiana	Various	356	4,714	6,848	38,335
Other States	Various	132	453	1,248	7,566
Total Net Proved Reserves		18,428	78,021	188,588	$ 1,088,714

(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, 2005, as set forth in the Company s reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc. of Houston, Texas.

(b) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2005, in accordance with Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143). See the Oil and Gas Reserve table for the standardized measure of discounted future net cash flow which is a required calculation by the SEC.

Table of Contents

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. The Entrada Area is characterized by a northwest plunging salt ridge with multiple stacked amplitudes trapped against the salt and various faults. We own a 20% working interest in this discovery with BP, the operator, holding the remaining working interest.

An integrated project team consisting of personnel from BP and Callon, along with Conoco-Phillips and Devon Energy Corporation, the owners of production facilities in nearby Garden Banks 783, are working on a front-end engineering design study to tie-back Entrada to the production facilities. Project sanction is targeted for the second half of 2006 with first production expected in 2008.

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater discovery was announced in September 1999, after we drilled the initial test well in 2,235 feet of water to a total depth of 16,241 feet and encountered over 120 feet of pay in two intervals. Subsequent sidetrack drilling from the wellbore was used to determine the extent of the discovery and a second well was drilled in the first quarter of 2000 to further delineate the extent of the pay intervals. We own a 15% working interest, Murphy Exploration & Production Company (Murphy), the operator, owns a 60% working interest and ENI Deepwater, LLC, owns the remaining 25% working interest.

In 2001 a drilling program began which included four development wells and one sidetrack. The program included production casing being set on six wells to provide initial production take-points and was completed in the first half of 2002. The construction of a floating production system, spar, at Medusa was completed during the second quarter of 2003. The A-1 well was completed and tied into the spar and commenced production in late November 2003. The remaining five wells were completed and commenced production in 2004. Mississippi Canyon 538 #4, North Medusa, was drilled in 2003 and was temporarily abandoned after encountering 28 feet of net pay. The well bore was re-entered in the fourth quarter of 2004, sidetracked and reached an objective depth of 9,600 feet in January 2005. The sidetrack encountered 46 feet of net pay, was completed and commenced initial production in April 2005 at a gross rate of 5,000 barrels of oil equivalent per day.

During 2005 the field produced 8.1 Bcfe net to us which accounted for 43% of our total production. Due to hurricanes and tropical storms during 2005, Medusa was not productive for approximately 102 days. After repairs of damage to Medusa s facilities and third-party transmission lines and production facilities caused by Hurricane Katrina, production was restored in November 2005 and pre-hurricane rates were achieved during December 2005. Medusa produced at an average daily gross rate of 34,000 barrels of crude oil and 35 MMcf during January 2006.

In December 2003, we transferred our undivided 15% working interest in the spar production facilities to Medusa Spar LLC in exchange for cash proceeds of approximately $25 million and a 10% ownership interest in the LLC. A detailed discussion of this transaction is included in Management s Discussion and Analysis of Financial Condition and Results of Operations- Off-Balance Sheet Arrangements .

Habanero, Garden Banks Block 341

During February 1999, the initial test well on our Habanero deepwater discovery encountered over 200 feet of net pay in two zones. Located in 2,000 feet of water, the well was drilled to a measured depth of

21,158 feet. We own an 11.25% working interest in the well. The well is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest being owned by Murphy.

A field delineation program began in mid-year 2001, which included three sidetracks of the discovery well. Production casing was set on this well through one of the sidetracks to the Habanero 52 oil and gas sand and the Habanero 55 gas sand. Also, a development well was drilled in the summer of 2003 which provides a take-point for production from the Habanero 52 oil sand. By means of a sub-sea completion and tie back to an existing production facility in the area operated by Shell, production from the Habanero 52 oil sand commenced in late November 2003 and from the Habanero 55 gas sand in January 2004. In July 2004 the #2 well producing the Habanero 52 oil sand developed mechanical difficulties with a subsurface control value and was shut-in resulting in a significant loss of production. Repairs were completed and production was restored in late December 2004. In addition, the #1 well producing the Habanero 55 gas sand was recompleted to the Habanero 55 oil sand in December 2004.

During 2005 Habanero produced 3.5 Bcfe net to us which accounted for 19% of our total production. Due to hurricanes and tropical storms during 2005 the field was not productive for approximately 85 days. After repairs of damage primarily to third-party transmission lines and production facilities caused by Hurricane Rita, production was restored in November 2005 and pre-hurricane rates were achieved during December 2005. Habanero produced at an average daily gross rate of 12,000 barrels of crude oil and 17 MMcf during January 2006.

Gulf of Mexico Shelf

West Cameron Block 295

During the third quarter of 2005, the #2 well reached a total depth of 15,775 feet and logged 150 feet of net pay in two zones. Each zone was encountered at the predicted depth and exceeded anticipated thickness. First production from the #2 well is expected in the first half of March 2006 at a gross rate of approximately 30 MMcf per day. Callon holds a 20.5% working interest in the block and Hydro Gulf of Mexico, LLC is the operator.

A second prospect on this block was also drilled during 2005. The #3 well was drilled to a depth of 16,286 feet in December 2005 and logged 110 feet of net (94 feet true vertical depth) pay in two zones. Production is expected to commence during May 2006 at a gross rate of approximately 10 MMcf per day. Callon holds a 20.5% working interest in the block and Cimarex Energy Company is the operator.

High Island Block A-540

The #1 well was spud in November 2005 and reached a total depth of 9,450 feet the following month after logging 32 feet of net pay in the objective section. First production is scheduled to commence in July 2006 at an anticipated gross rate of approximately 11 MMcfe per day. The company owns a 60% working interest and Walter Oil and Gas is the operator.

Mobile Blocks 953/955

We own a 100% working interest in these two blocks and we are the operator. In the fourth quarter of 2001, we initiated a production acceleration program for Mobile Blocks 952, 953 and 955, which were being produced through the Mobile Block 864 Unit facilities and were production constrained. An

Table of Contents

acceleration well was successfully drilled in the fourth quarter of 2001 and stand-alone production facilities were installed and production flow lines were rerouted to the new facilities. Production commenced through the new facilities in April 2002. In order to completely produce the proved reserves of the field we drilled a development well on Mobile Block 955 during the first quarter of 2004.

During 2005 the three wells on the blocks produced 2.5 Bcf of natural gas net to us which accounted for 13.2% of our total production. Due to hurricanes and tropical storms during 2005, two of the wells were not productive for approximately 48 days and one well was down for 136 days. After repairs of damages caused by Hurricane Katrina, the field produced at an average daily gross rate of 7 MMcf during January 2006.

Mobile Block 864 Unit

We operate the Mobile Block 864 Unit, in which we have a 66.4% working interest. The Unit has four producing wells, unit production facilities and covers portions of three blocks.

During 2005 the Unit produced 833 MMcf of natural gas net to us which accounted for 4.4% of our total production. Due to hurricanes and tropical storms during 2005, the Unit was not productive for approximately 48 days. After repairs of damages caused by Hurricane Katrina, production was restored in November 2005. The field produced at an average daily gross rate of 4 MMcf during January 2006.

North Padre Island Block 913

An exploratory well was drilled to a vertical depth of 8,082 feet in the fourth quarter of 2004 and found natural gas pay in multiple intervals. Currently, the well is being tied back to existing infrastructure on a nearby block. We are the operator and own a 50% working interest. First production is expected to commence in March 2006 at a gross rate of 15 MMcfe per day. The initial production was delayed due to equipment availability problems caused by Hurricanes Katrina and Rita.

East Cameron Block 90

The #1 well reached total depth of 8,500 feet in January 2005 and encountered 42 feet of net pay at two intervals, including 34 feet in the primary objective. The well commenced initial production in December 2005 at a gross rate of 5 MMcf per day. Callon operates and owns a 61.7% working interest. The initial production was delayed due to equipment availability problems caused by Hurricanes Katrina and Rita.

High Island Block 119

An initial exploratory well and one development well were drilled and completed in 2004. First production began in the third quarter of 2004. An exploratory well in an offsetting fault block was spud late in the fourth quarter of 2004 and was completed in 2005. We own a 22% working interest and Kerr- McGee Oil and Gas Corporation is the operator.

These three wells produced 1.2 Bcfe of natural gas net to our interest during 2005 which accounted for 6.5% of our total production. Due to hurricanes and tropical storms during 2005, the field was not productive for approximately 102 days. After repairs of damages caused by Hurricane Rita, production was restored in January 2006. The field is currently producing at an average daily gross rate of 13.0 MMcfe.

Table of Contents

Oil and Gas Reserves

The following table sets forth certain information about our estimated proved reserves as reported by Huddleston & Co., Inc. as of the dates set forth below.

	Years Ended December 31, 2005	2004 (In thousands)	2003
Proved developed:			
Oil (Bbls)	7,323	10,292	9,919
Gas (Mcf)	30,982	33,982	31,415
Mcfe	74,921	95,735	90,926
Proved undeveloped:			
Oil (Bbls)	11,105	9,456	13,790
Gas (Mcf)	47,039	38,637	43,276
Mcfe	113,667	95,373	126,017
Total proved:			
Oil (Bbls)	18,428	19,748	23,709
Gas (Mcf)	78,021	72,619	74,691
Mcfe	188,588	191,108	216,943
Estimated pre-tax future net cash flows (a)	$ 1,487,817	$ 892,145	$ 838,847
Pre-tax discounted present value (a)	$ 1,088,714	$ 612,595	$ 570,463
Standardized measure of discounted future net cash flows(a)	$ 837,552	$ 515,893	$ 519,026

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2005, in accordance with SFAS 143.

Our independent reserve engineers, Huddleston & Co., Inc., prepared the estimates of the proved reserves and the future net cash flows and present value thereof attributable to such proved reserves. Reserves were estimated using oil and gas prices and production and development costs in effect on December 31 of each

such year, without escalation, and were otherwise prepared in accordance with SEC regulations regarding disclosure of oil and gas reserve information.

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

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

Present Activities and Productive Wells

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

	Years Ended December 31,					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	1	0.15			2	.23
Gas			2	1.22		
Non-productive						
Total	1	0.15	2	1.22	2	.23
Exploration:						
Oil					1	.15
Gas	7	2.42	2	.72		
Non-productive	4	1.25	5	1.24	1	.20
Total	11	3.67	7	1.96	2	.35

Table of Contents

The following table sets forth our productive wells as of December 31, 2005:

	Wells	
	Gross	Net
Oil:		
Working interest	39.00	3.75
Royalty interest	192.00	3.14
Total	231.00	6.89
Gas:		
Working interest	33.00	12.70
Royalty interest	209.00	1.58
Total	242.00	14.28

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to gas reserves on a Mcfe basis. However, some of our wells produce both oil and gas. At December 31, 2005, we had no wells with multiple completions. At December 31, 2005, 1 gross (0.033 net) exploration oil well and 1 gross (0.205 net) exploration gas well were in progress.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2005.

	Leasehold Acreage			
	Developed		Undeveloped	
Location	**Gross**	**Net**	**Gross**	**Net**
Louisiana	6,092	3,882	13,516	5,584
Texas	78		15,870	6,680
Other states			681	509
Federal waters	108,102	56,770	257,140	78,523
Total	114,272	60,652	287,207	91,296

As of December 31, 2005, we owned various royalty and overriding royalty interests in 1,336 net developed and 6,862 net undeveloped acres. In addition, we owned 4,309 developed and 121,691 undeveloped mineral acres.

Major Customers

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and gas production during each of the 12-month periods ended:

Table of Contents

	December 31,		
	2005	2004	2003
Shell Trading Company	34%	30%	
Louis Dreyfus Energy Services	16%	23%	27%
Plains Marketing, L.P.	16%	13%	
Chevron Texaco Natural Gas	10%	6%	
Reliant Energy Services		6%	28%
Prior Energy Corporation			20%

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

Title to Properties

We believe that the title to our oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind owned by us.

Table of Contents

ITEM 3. LEGAL PROCEEDINGS

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

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2005.

Table of Contents

PART II.

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

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

	Quarter Ended	High	Low
2004:			
	First quarter	$11.23	$ 8.70
	Second quarter	14.27	10.15
	Third quarter	14.40	11.10
	Fourth quarter	14.72	12.30
2005:			
	First quarter	$18.00	$13.22
	Second quarter	16.12	12.42
	Third quarter	21.25	14.81
	Fourth quarter	22.29	16.65

As of March 2, 2006, there were approximately 4,179 common stockholders of record.

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

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2005 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results.

Table of Contents

CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(In thousands, except per share amounts)

	Years Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Statement of Operations Data:					
Operating revenues:					
Oil and gas sales	$ 141,290	$ 119,802	$ 73,697	$ 61,171	$ 60,010
Operating expenses:					
Lease operating expenses	24,377	22,308	11,301	11,030	11,252
Depreciation, depletion and amortization	44,946	47,453	28,253	27,096	21,081
General and administrative	8,085	8,758	4,713	4,705	4,635
Accretion expense	3,549	3,400	2,884		
Derivative expense	6,028	1,371	535	708	
Total operating expenses	86,985	83,290	47,686	43,539	36,968
Income from operations	54,305	36,512	26,011	17,632	23,042
Other (income) expenses:					
Interest expense	16,660	20,137	30,614	26,140	12,805
Other (income)	(998)	(357)	(444)	(1,004)	(1,742)
Loss on early extinguishment of debt		3,004	5,573		
Gain on sale of pipeline				(2,454)	
Gain on sale of Enron derivatives				(2,479)	
Writedown of Enron derivatives					9,186
Total other (income) expenses	15,662	22,784	35,743	20,203	20,249
Income (loss) before income taxes	38,643	13,728	(9,732)	(2,571)	2,793
Income tax expense (benefit)	13,209	(6,697)	8,432	(900)	977
Income (loss) before Medusa Spar LLC and cumulative effect of change in accounting principle	25,434	20,425	(18,164)	(1,671)	1,816
Income (loss) on Medusa Spar LLC, net of tax	1,342	1,076	(8)		
Income (loss) before cumulative effect of change in in accounting principle	26,776	21,501	(18,172)	(1,671)	1,816
Cumulative effect of change in accounting principle, net of tax			181		

Net income (loss)	26,776	21,501	(17,991)	(1,671)	1,816
Preferred stock dividends	318	1,272	1,277	1,277	1,277
Net income (loss) available to common shares	$ 26,458	$ 20,229	$ (19,268)	$ (2,948)	$ 539

25

Table of Contents

CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(In thousands, except per share amounts)

	Years Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Net income (loss) available to common shares	$ 26,458	$ 20,229	$ (19,268)	$ (2,948)	$ 539
Net income (loss) per common share:					
Basic:					
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.43	$ 1.28	$ (1.42)	$ (.22)	$ .04
Cumulative effect of change in accounting principle, net of tax			.01		
Net income (loss) available to common	$ 1.43	$ 1.28	$ (1.41)	$ (.22)	$ .04
Diluted:					
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.28	$ 1.22	$ (1.42)	$ (.22)	$ .04
Cumulative effect of change in accounting principle, net of tax			.01		
Net income (loss) available to common	$ 1.28	$ 1.22	$ (1.41)	$ (.22)	$ .04
Shares used in computing net income (loss) per common share:					
Basic	18,453	15,796	13,662	13,387	13,273
Diluted	20,883	17,678	13,662	13,387	13,366
Balance Sheet Data (end of period):					
Oil and gas properties, net	$ 447,364	$ 406,690	$ 390,163	$ 377,661	$ 343,158
Total assets	$ 533,776	$ 457,523	$ 496,032	$ 410,613	$ 372,095
Long-term debt, less current portion	$ 188,813	$ 192,351	$ 214,885	$ 248,269	$ 161,733
Stockholders equity	$ 228,048	$ 198,312	$ 133,261	$ 140,960	$ 147,224

We use the full-cost method of accounting. Under this method of accounting, our net capitalized costs to acquire explore and develop oil and gas properties may not exceed the standardized measure of our proved reserves. If these capitalized costs exceed a ceiling amount, the excess is charged to expense.

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

The following discussion is intended to assist in an understanding of our financial condition and results of operations. Our Consolidated 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

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

Significant events of our financial and operating results for the year ended December 31, 2005 included an increase in the borrowing base from $60 million to $70 million, production downtime in the third and fourth quarter associated with the tropical storm activity and the redemption of all our outstanding shares of $2.125 Convertible Exchange Preferred Stock, Series A. As a result of the redemption, we will benefit from an annual cash savings of $1.3 million in dividend payments.

We expect that planned 2006 capital expenditures of approximately $125 million will be funded with cash flows from operations and supplemented, if necessary, with our senior secured credit facility which had $62.5 million available on December 31, 2005. For a more detailed discussion of outstanding debt see Note 5 to our Consolidated Financial Statements.

Our estimated net proved oil and gas reserves decreased at December 31, 2005 to 188.6 Bcfe. This represents a decrease of 1% from previous year-end 2004 estimated proved reserves of 191.1 Bcfe. We produced 18.8 Mmcfe and had net reserve additions of 16.3 Mmcfe.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include weather conditions in the United States, the condition of the United States economy, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil and natural gas, the price of foreign imports and the availability of alternate fuel sources. Any substantial and extended decline in the price of crude oil or natural gas would have an adverse effect on our carrying value of our proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. We use derivative financial instruments (see Note 6 to our Consolidated Financial Statements and Item 7A. Quantitative and Qualitative Disclosures About Market Risks) for price protection purposes on a limited amount of our future production and do not use them for trading purposes. On a Mcfe basis, natural gas represents approximately 58% of the budgeted 2006 production and 41% of proved reserves at year-end 2005.

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

Table of Contents

Summary of Significant Accounting Policies

On December 16, 2004, the FASB issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which is a revision of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123). SFAS 123R supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees , and amends Statement of Financial Accounting Standards No. 95, Statement of Cash Flows . Generally, the approach in SFAS 123R is similar to the approach described in SFAS 123. However, SFAS 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative.

In April 2005, the SEC delayed the effective date of SFAS 123R for public companies to no later than the beginning of the first fiscal year beginning after June 15, 2005. Early adoption will be permitted in periods in which financial statements have not yet been issued. SFAS 123R permits public companies to adopt its requirements using one of two methods below:

A modified prospective method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS 123R for all share-based payments granted after the effective date and (b) based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123R that remain unvested on the effective date; or

A modified retrospective method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

As permitted by SFAS 123, we currently account for share-based payments to employees using APB Opinion 25 s intrinsic value method and, as such, generally recognize no compensation cost for employee stock options. Accordingly, the adoption of SFAS 123R s fair value method could have a significant impact on our result of operations, although it will have no impact on our overall financial position. The impact of adoption of SFAS 123R cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted SFAS 123R in prior periods, the impact of that standard would have approximated the impact of SFAS 123 as described in the disclosure of pro forma net income and earnings per share in Note 2 to our Consolidated Financial Statements. We adopted SFAS 123R on January 1, 2006 using the modified prospective method.

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

Table of Contents

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

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

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

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

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

- prior to the adoption of SFAS 143, estimated costs to dismantle, abandon and restore a proved property were added to the full-cost pool for the purposes of DD&A. Subsequent to the adoption of SFAS 143, effective January 1, 2003, these costs are included in the full-cost pool. Such cost estimates are periodically updated as additional information becomes available. As discussed below specifically SFAS 143, beginning January 1, 2003, we changed the method for which we account for such costs.

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

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

Ceiling Test. Under the full-cost accounting rules, capitalized costs included in the full-cost pool, net of accumulated depreciation, depletion and amortization (DD&A), cost of unevaluated properties and deferred income taxes, may not exceed the present value of our estimated future net cash flows from proved oil and gas reserves, discounted at 10%, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects. These rules generally require that, in estimating future net cash flow, we assume that future oil and gas production will be sold at the unescalated market price for oil and gas received at the end of each fiscal quarter and that future costs to produce oil and gas will remain constant at the prices in effect at the end of the fiscal quarter. We are required to write-down and charge to

Table of Contents

earnings the amount, if any, by which these costs exceed the discounted future net cash flows, unless prices recover sufficiently before the date of our financial statements. Given the volatility of oil and gas prices, it is likely that our estimates of discounted future net cash flows from proved oil and gas reserves will change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that writedowns of oil and gas properties could occur in the future.

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

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

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

- the liability to pay royalties to the Mineral Management Service. See Note 7 of our Consolidated Financial Statements for a more detailed discussion of this potential liability.

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

Unproved Properties. Costs associated with properties that do not have proved reserves, including capitalized interest, are excluded from the full-cost pool. These unproved properties are included in the line item Unevaluated properties excluded from amortization. Unproved property costs are transferred to the full-cost pool when wells are completed on the properties or the properties are sold. In addition, we are required to determine whether our unproved properties are impaired and, if so, add the costs of such properties to the full-cost pool. We determine whether an unproved property should be impaired by periodically reviewing our exploration program on a property by property basis. This determination may require the exercise of substantial judgment by our management.

Asset Retirement Obligations. In June 2001, the FASB issued SFAS 143 effective for fiscal years beginning after June 15, 2002. SFAS 143 essentially requires entities to record the fair value of a liability for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. We adopted the statement on January 1, 2003 resulting in a cumulative effect of accounting change of $181,000, net of tax. See Note 8 to our Consolidated Financial Statements.

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

See Note 6 to our Consolidated Financial Statements.

Income Taxes. We follow 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.

SFAS 109 provides for the weighing of positive and negative evidence in determining whether it is more likely than not that a deferred tax asset is recoverable. We incurred losses in 2002 and 2003 and had losses on an aggregate basis for the three-year period ended December 31, 2003. Because of these cumulative losses we established a full valuation allowance of $11.5 million as of December 31, 2003.

As a result of production from our first two deepwater projects starting in November 2003, as well as refinancing our highest cost debt in 2004, we achieved profitable operations and had income on an aggregate basis for the three-year period ended December 31, 2004. As a result, we reversed the valuation allowance in 2004 which had a balance of $7.0 million as of December 31, 2004. See Note 3 to the Consolidated Financial Statements for further disclosure.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Net cash and cash equivalents decreased during 2005 to $2.6 million, down $0.7 million. Cash provided from operating activities during 2005 totaled $74 million, up 4% from $71 million in 2004. Dividends paid on preferred stock in 2005 were $318,000.

On June 15, 2004, we closed on a three-year senior secured credit facility underwritten by Union Bank of California, N.A. The credit facility includes a borrowing base, determined by the lender, of $70 million, which may be adjusted semi-annually and could increase to a maximum of $175 million. As of December 31, 2005 there were no borrowings outstanding under the facility and we had an aggregate of $7.5 million in outstanding letters of credit issued under the credit facility. These letters of credit secure obligations under the outstanding hedging contracts described in Note 6 to the Consolidated Financial Statements. The outstanding letters of credit reduce the amount available for borrowings under the credit facility. As a result, $62.5 million was available for future borrowings under the credit facility as of December 31, 2005.

In December 2003 and March 2004, we closed on our 9.75% senior notes due 2010 in the aggregate principal amount of $200 million. The net proceeds from these notes and the public offering of 3,450,000 shares of common stock in the second quarter of 2004 were used to restructure our debt that was maturing in 2004 and 2005. See Note 5 to the Consolidated Financial Statements for a more detailed discussion of our debt restructure.

The indenture governing our 9.75% senior notes due 2010 and our senior secured credit facility contain various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, our senior secured credit facility contains covenants for maintenance of certain financial ratios. We were in compliance with these covenants at December 31, 2005.

Table of Contents

Our oil and gas reserves as reported by Huddleston & Co., Inc. were 189 Bcfe of natural gas equivalents on December 31, 2005. Our cash flow from operations during 2005 was generated by the production of 18.8 Bcfe after incurring significant downtime at our major producing properties due to tropical storms and hurricanes during the last half of the year. Production of our reserves during 2006, without weather-related downtime, is projected to be higher than 2005 due to eight new discoveries scheduled to commence initial production during 2006 which will offset traditional declines from our current producing properties.

Our planned capital expenditures for 2006 total $125 million. The current portion of our asset retirement obligation in the amount of $21.7 million and capitalized interest and general and administrative expenses are included in the $125 million. Capital expenditure plans for 2006 include:

- the completion and development of pre-2006 shelf discoveries;
- the discretionary drilling of approximately 18 shelf and onshore exploratory wells;
- drilling of three deepwater prospects;
- lease and seismic acquisition; and
- capitalized interest and overhead.

We believe that our operating cash flow and our credit facility will be adequate to meet our capital, debt repayment, and operating requirements for 2006. We fund our day-to-day operating expenses and capital expenditures from operating cash flows, supplemented as needed by borrowings under our credit facility. In addition, we have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future. Because of the liquidity and capital resources alternatives available to us, including internally generated cash flows, our management believes that our short-term and long-term liquidity is adequate to fund operations, including our capital spending program, repayment of maturing debt and any amounts that may ultimately be paid in connection with contingencies.

Our cash flow, both in the short and long-term, is impacted by highly volatile oil and natural gas prices, production levels, industry trends impacting operating expenses and our ability to continue to acquire or find reserves at competitive prices. Cash flow forecasts for internal use by management are revised monthly in response to changing market conditions and production projections. We routinely adjust capital expenditure budgets within the planned total amount in response to the adjusted cash flow forecasts and market trends in drilling and acquisitions costs.

Table of Contents

The following table describes our outstanding contractual obligations (in thousands) as of December 31, 2005:

		Payments due by Period			
Contractual Obligations	Total	Less Than One Year	One-Three Years	Three-Five Years	More Than-Five Years
Senior Secured Credit Facility	$	$	$	$	$
9.75% Senior Notes	200,000			200,000	
Capital lease (future minimum payments)	1,710	439	577	449	245
Throughput Commitments:					
Medusa Spar LLC	12,684	3,836	5,532	3,316	
Medusa Oil Pipeline	606	206	186	113	101
	$ 215,000	$ 4,481	$ 6,295	$ 203,878	$ 346

Off-Balance Sheet Arrangements

In December 2003, we announced the formation of a limited liability company, Medusa Spar LLC, which now owns a 75% undivided ownership interest in the deepwater spar production facilities on our Medusa Field in the Gulf of Mexico. We contributed a 15% undivided ownership interest in the production facility to Medusa Spar LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC will earn a tariff based upon production volume throughput from the Medusa area. We are obligated to process our share of production from the Medusa Field and any future discoveries in the area through the spar production facilities. This arrangement allows us to defer the cost of the spar production facility over the life of the Medusa Field. Our cash proceeds were used to reduce the balance outstanding under our senior secured credit facility. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. On December 31, 2005, $47.0 million of the financing was outstanding. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy. We are accounting for our 10% ownership interest in the LLC under the equity method.

2005 Hurricane Activity

During 2005, we encountered numerous tropical storms and hurricanes which caused all of our fields located in the Gulf of Mexico area to be shut-in at various times during the year. Hurricanes Katrina and Rita, being the most devastating of these tropical weather systems, caused substantial downtime in the third and fourth quarter of 2005 which was primarily due to damage incurred to oil and gas transmission lines and production facilities owned by third parties.

Our major fields, Medusa, Habanero and Mobile Bay Blocks 863, 864, 907, 953 and 955, incurred damage; but the fields were repaired and brought back online in the fourth quarter of 2005. Our properties are insured and we expect to get reimbursed for most of our costs incurred for damage repairs, less our $250,000 deductible per occurrence. We estimated that our cost to repair the hurricane damages will be approximately $4.0 million. As of December 31, 2005, we had expensed $1.2 million for damages related to tropical storms and hurricanes for deductibles and the costs of repairs not covered by our property insurance carrier.

Table of Contents

The tropical storms and hurricanes during 2005 had a significant impact on our cash flows from properties. Scheduled below are our major properties which incurred lost production days:

Field	Production Days Lost
Medusa	102
Habanero	85
Mobile Block 864 Unit	48
Mobile 953	48
Mobile 955	136
High Island 119	102

These properties account for 86% of our production for 2005. In addition, initial production from our recent discoveries at North Padre Island Block 913 and East Cameron Block 90 were delayed due to equipment availability problems. See Significant Properties for more detail by property.

We are in the process of negotiating our insurance renewal for the year ended March 31, 2007. We expect our insurance premiums to increase but can not estimate the amount at this time.

Table of Contents

Results of Operations

The following table sets forth certain operating information with respect to our oil and gas operations for each of the three years in the period ended December 31, 2005.

	December 31,		
	2005	2004	2003
Production:			
Oil (MBbls)	1,837	1,736	268
Gas (MMcf)	7,768	11,387	12,315
Total production (MMcfe)	18,787	21,801	13,923
Average daily production (MMcfe)	51.5	59.6	38.1
Average sales price:			
Oil (per Bbl) (a)	$ 41.61	$ 28.71	$ 28.72
Gas (per Mcf)	$ 8.35	$ 6.15	$ 5.36
Total (per Mcfe)	$ 7.52	$ 5.50	$ 5.29
Oil and Gas revenues (in thousands):			
Oil revenue	$ 76,425	$ 49,826	$ 7,696
Gas revenue	64,865	69,976	66,001
Total	$ 141,290	$ 119,802	$ 73,697
Oil and gas production costs (in thousands):			
Lease operating expenses	$ 24,377	$ 22,308	$ 11,301
Additional per Mcfe data:			
Sales price	$ 7.52	$ 5.50	$ 5.29
Lease operating expenses	1.30	1.02	.81
Operating margin	$ 6.22	$ 4.48	$ 4.48
Depletion	$ 2.39	$ 2.18	$ 2.03
Accretion	$ .19	$ .16	$ .21
General and administrative (net of management fees)	$ .43	$ .40	$ .34

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price per barrel of oil:

	2005	2004	2003
Average NYMEX oil price	$ 56.57	$ 41.38	$ 31.08
Basis differential and quality adjustments	(8.45)	(4.60)	(1.94)
Transportation	(1.26)	(1.27)	(0.42)
Hedging	(5.25)	(6.80)	
Average realized oil price	$ 41.61	$ 28.71	$ 28.72

Table of Contents

Comparison of Results of Operations for the Years Ended December 31, 2005 and 2004

Oil and Gas Revenues

Total oil and gas revenues increased 18% from $119.8 million in 2004 to $141.3 million in 2005 primarily due to pricing. Total production for 2005 decreased by 14% versus 2004 as a result of downtime associated with the tropical storm and hurricane activity in 2005.

Gas production during 2005 totaled 7.8 Bcf and generated $64.9 million in revenues compared to 11.4 Bcf and $70.0 million in revenues during the same period in 2004. Average gas prices realized for 2005 were $8.35 per Mcf compared to $6.15 per Mcf during the same period last year. The decrease in production was primarily due to significant downtime related to tropical storm and hurricane activity and the normal and expected decline in production from our Mobile area fields and older properties. See our discussion of Significant Properties for a more detailed discussion by property of this downtime.

Oil production during 2005 totaled 1,837,000 barrels and generated $76.4 million in revenues compared to 1,736,000 barrels and $49.8 million in revenues for the same period in 2004. Average oil prices realized in 2005 were $41.61 per barrel compared to $28.71 per barrel in 2004. Oil production increased during 2005 despite significant downtime resulting from tropical storms and hurricanes. The increase was primarily attributable to our deepwater property Medusa which began production in 2003 from a single well with five others being brought online during 2004 and all six producing during 2005. In addition, our North Medusa discovery was completed and initial production commenced through the field facilities in April 2005. See our discussion of Significant Properties for more detail regarding production and downtime.

Lease Operating Expenses

Lease operating expenses for 2005 increased by 9% to $24.4 million compared to $22.3 million for the same period in 2004. The increase was primarily due to lease operating expenses related to our deepwater discovery, Medusa, which had higher throughput charges as a result of higher production rates and the addition of our High Island Block 119 field, which began producing late in the third quarter of 2004.

In addition, lease operating expenses for 2005 included the costs of repairs to our properties for damages caused by tropical storms and hurricanes in the net amount of $1.2 million. This amount covers the deductibles and an estimate of repairs not expected to be reimbursed by our property insurance carrier.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2005 and 2004 were $44.9 million and $47.5 million, respectively. The 5% decrease was primarily due to lower production volumes for 2005 compared to 2004. The decrease was partially offset by a higher average depletion rate.

Accretion Expense

Accretion expense for 2005 and 2004 of $3.5 million and $3.4 million, respectively, represents accretion for our asset retirement obligations. The increase was due to the addition of plugging and abandonment obligations. See Note 8 to the Consolidated Financial Statements.

Table of Contents

General and Administrative

General and administrative expenses for 2005, net of amounts capitalized, were $8.1 million compared to $8.8 million incurred in 2004. There was a charge in general and administrative expenses of $2.6 million in the first quarter of 2004 for the early retirement of two executive officers of the Company. The decrease was partially offset by reduced capitalized overhead for 2005 and a non-cash charge during the second quarter of 2005 for the accelerated vesting of performance shares in the amount of $930,000 for an executive officer and two directors of the Company, two of whom are deceased.

Interest Expense

Interest expense decreased by 17% in 2005 to $16.7 million compared to $20.1 million in 2004. This decrease is primarily attributable to an equity offering completed in the second quarter of 2004 in which a portion of the proceeds were used to redeem $33 million of 11% Senior Subordinated Notes .

Loss on Early Extinguishment of Debt

A loss of $3.0 million was incurred in 2004 for the write-off of deferred financing costs, pre-payment premiums and bond discounts associated with the early extinguishment of debt.

Income Taxes

For 2005, we had an income tax expense of $13.2 million compared to an income tax benefit of $6.7 million in 2004. The income tax benefit for 2004 resulted primarily from the reversal of the valuation allowance established in 2003 against our deferred tax asset. As a result of production from the Company s first two deepwater projects starting in November 2003, as well as refinancing its highest cost debt in 2004, the Company achieved profitable operations and has income on an aggregate basis for the three-year period ended December 31, 2004 and the Company reversed the valuation allowance. See Note 3 to our Consolidated Financial Statements for a more detailed discussion.

Table of Contents

Comparison of Results of Operations for the Years Ended December 31, 2004 and 2003

Oil and Gas Revenues

Total production for 2004 increased by 57% versus 2003 and total oil and gas revenues increased 63% from $73.7 million in 2003 to $119.8 million in 2004. Increased production was primarily due to our deepwater discoveries, Medusa and Habanero, which began producing late in the fourth quarter of 2003.

Gas production during 2004 totaled 11.4 Bcf and generated $70.0 million in revenues compared to 12.3 Bcf and $66.0 million in revenues during the same period in 2003. Average gas prices realized for 2004 were $6.15 per Mcf compared to $5.36 per Mcf during the same period the previous year. The decrease in production was primarily due to downtime for Hurricane Ivan and the normal and expected decline in production from our Mobile area fields and older properties. These factors were partially offset by production from Medusa and Habanero.

Oil production during 2004 totaled 1,736,000 barrels and generated $49.8 million in revenues compared to 268,000 barrels and $7.7 million in revenues for the same period in 2003. Average oil prices realized in 2004 were $28.71 per barrel compared to $28.72 per barrel in 2003. The increase in production was due to the initial production from our deepwater discoveries, Medusa and Habanero. The production increase was offset slightly by downtime for Hurricane Ivan and normal and expected declines in production from older properties.

Lease Operating Expenses

Lease operating expenses for 2004 increased by 97% to $22.3 million compared to $11.3 million for the same period in 2003. The increase was primarily due to lease operating expenses related to our deepwater discoveries, Medusa and Habanero.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2004 and 2003 were $47.5 million and $28.3 million, respectively. The 68% increase was primarily due to higher production volumes for 2004 compared to 2003.

Accretion Expense

Accretion expense for 2004 and 2003 of $3.4 million and $2.9 million, respectively, represents accretion for our asset retirement obligations. The increase was due to the addition of plugging and abandonment obligations. See Note 8 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses for 2004, net of amounts capitalized, were $8.8 million compared to $4.7 million incurred in 2003. There was a charge in general and administrative expenses of $2.6 million in the first quarter of 2004 for the early retirement of two executive officers of the Company. Also reduced capitalized overhead, higher directors fees, and increased independent and internal audit costs resulting from the implementation of The Sarbanes-Oxley Act, Section 404 contributed to the increase in general and administrative expenses.

Table of Contents

Interest Expense

Interest expense decreased by 34% in 2004 to $20.1 million compared to $30.6 million in 2003. This is a result of lower debt levels and lower interest rates due to the restructuring of debt in December 2003 and during the six-month period ended June 30, 2004 in additional to an equity offering completed in the second quarter of 2004. In addition, amortization of deferred financing costs and bond discounts decreased due to the write-off of unamortized deferred financing costs and bond discounts associated with the early extinguishment of debt.

Loss on Early Extinguishment of Debt

A loss of $3.0 million and $5.6 million was incurred in 2004 and 2003, respectively. Both were incurred for the write-off of deferred financing costs, pre-payment premiums and bond discounts associated with the early extinguishment of debt.

Income Taxes

The income tax benefit of $6.7 million in 2004 resulted primarily from the reversal of the valuation allowance established in 2003 against our deferred tax asset. As a result of production from the Company s first two deepwater projects starting in November 2003, as well as refinancing its highest cost debt in 2004, the Company achieved profitable operations and has income on an aggregate basis for the three-year period ended December 31, 2004 and the Company reversed the valuation allowance. See Note 3 to our Consolidated Financial Statements for a more detailed discussion.

Table of Contents

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

The Company also enters into price collars to reduce the risk of changes in oil and gas prices. Under these arrangements, no payments are due by either party so long as the market price is above the floor price set in the collar and below the ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to the Company and if the price is above the ceiling, the counter-party receives the difference from the Company. Another type of hedging contract Callon has entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to the Company. The Company enters into these various agreements to reduce the effects of volatile oil and gas prices and does not enter into hedge transactions for speculative purposes. See Note 6 to the Consolidated Financial Statements for a description of the Company s hedged position at December 31, 2005. There have been no significant changes in market risks faced by the Company since the end of 2005.

Based on projected annual sales volumes for 2006 (excluding forecast production increases over 2005), a 10% decline in the prices Callon receives for its crude oil and natural gas production would have an approximate $18 million impact on our revenues.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors
Callon Petroleum Company

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2005. 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 the standards of the Public Company Accounting Oversight Board (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 consolidated financial position of Callon Petroleum Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the financial statements, effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations .

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Callon Petroleum Company s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 9, 2006, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 9, 2006

Table of Contents

CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,565	$ 3,266
Accounts receivable	33,195	14,928
Deferred tax asset-current	26,770	5,676
Restricted investments-current	4,110	2,055
Fair market value of derivatives	889	1,570
Other current assets	1,998	581
Total current assets	69,527	28,076
Oil and gas properties, full-cost accounting method:		
Evaluated properties	937,698	862,101
Less accumulated depreciation, depletion and amortization	(539,399)	(494,453)
	398,299	367,648
Unevaluated properties excluded from amortization	49,065	39,042
Total oil and gas properties	447,364	406,690
Other property and equipment, net	1,605	1,541
Deferred tax asset		2,986
Long-term gas balancing receivable	403	725
Restricted investments	1,858	5,687
Investment in Medusa Spar LLC	11,389	9,787
Other assets, net	1,630	2,031
Total assets	$ 533,776	$ 457,523
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 39,323	$ 15,728
Fair market value of derivatives	1,247	2,993
Undistributed oil and gas revenues	721	1,162
Accrued net profits interest payable		1,927
Suspended Medusa oil royalties		5,430
Asset retirement obligations-current	21,660	13,300
Current maturities of long-term debt	263	576

Total current liabilities	63,214	41,116
Long-term debt	188,813	192,351
Asset retirement obligations	16,613	24,982
Deferred tax liability	31,633	
Accrued liabilities to be refinanced	5,000	
Other long-term liabilities	455	762
Total liabilities	305,728	259,211
Stockholders equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized; -0- and 596,671 shares of Convertible Exchangeable Preferred Stock, Series A issued and outstanding at December 31, 2005 and 2004, respectively		6
Common Stock, $.01 par value; 30,000,000 shares authorized; 19,357,138 shares and 17,616,596 shares issued and outstanding at December 31, 2005 and 2004, respectively	194	176
Unearned compensation-restricted stock	(3,334)	(5,352)
Capital in excess of par value	220,360	220,664
Other comprehensive loss	(331)	(1,883)
Retained earnings (deficit)	11,159	(15,299)
Total stockholders equity	228,048	198,312
Total liabilities and stockholders equity	$ 533,776	$ 457,523

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

43

Table of Contents

Callon Petroleum Company
Consolidated Statements of Operations
For the Years Ended December 31, 2005, 2004 and 2003
(In thousands, except per share amounts)

	2005	2004	2003
Operating revenues:			
Oil and gas sales	$ 141,290	$ 119,802	$ 73,697
Operating expenses:			
Lease operating expenses	24,377	22,308	11,301
Depreciation, depletion and amortization	44,946	47,453	28,253
General and administrative	8,085	8,758	4,713
Accretion expense	3,549	3,400	2,884
Derivative expense	6,028	1,371	535
Total operating expenses	86,985	83,290	47,686
Income from operations	54,305	36,512	26,011
Other (income) expenses:			
Interest expense	16,660	20,137	30,614
Other (income)	(998)	(357)	(444)
Loss on early extinguishment of debt		3,004	5,573
Total other (income) expenses	15,662	22,784	35,743
Income (loss) before income taxes	38,643	13,728	(9,732)
Income tax expense (benefit)	13,209	(6,697)	8,432
Income (loss) before Medusa Spar LLC and cumulative effect of change in accounting principle	25,434	20,425	(18,164)
Income (loss) on Medusa Spar LLC, net of tax	1,342	1,076	(8)
Income (loss) before cumulative effect of change in accounting principle	26,776	21,501	(18,172)
Cumulative effect of change in accounting principle, net of tax			181
Net income (loss)	26,776	21,501	(17,991)
Preferred stock dividends	318	1,272	1,277
Net income (loss) available to common shares	$ 26,458	$ 20,229	$ (19,268)

Net income (loss) per common share:			
Basic			
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.43	$ 1.28	$ (1.42)
Cumulative effect of change in accounting principle, net of tax			0.01
Net income (loss) available to common share	$ 1.43	$ 1.28	$ (1.41)
Diluted			
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.28	$ 1.22	$ (1.42)
Cumulative effect of change in accounting principle, net of tax			0.01
Net income (loss) available to common share	$ 1.28	$ 1.22	$ (1.41)
Shares used in computing net income (loss) per share amounts:			
Basic	18,453	15,796	13,662
Diluted	20,883	17,678	13,662

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

Table of Contents

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY
(In thousands)

	Preferred Stock	Common Stock	Unearned Restricted Stock Compensation	Capital in Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stock-holders Equity
Balances, December 31, 2002	$ 6	$ 139	$ (826)	$ 158,370	$ (469)	$ (16,260)	$ 140,960
Comprehensive income (loss):							
Net loss						(17,991)	
Other comprehensive income					449		
Total comprehensive loss							(17,542)
Preferred stock dividends						(1,277)	(1,277)
Shares issued pursuant to employee benefit and option plan		1		427			428
Employee stock purchase plan				127			127
Restricted stock		(1)	454	(516)			(63)
Warrants				10,628			10,628
Balances, December 31, 2003	6	139	(372)	169,036	(20)	(35,528)	133,261
Comprehensive income (loss):							
Net income						21,501	
Other comprehensive (loss)					(1,863)		
Total comprehensive income							19,638
Preferred stock dividend						(1,272)	(1,272)
Sale of common stock		35		44,012			44,047
Shares issued pursuant to employee benefit and option plan		1		720			721
Employee stock purchase plan		1		208			209
Tax benefits related to stock compensation plans				1,214			1,214
Restricted stock			(4,980)	5,474			494
Balances, December 31, 2004	6	176	(5,352)	220,664	(1,883)	(15,299)	198,312
Comprehensive income (loss):							
Net income						26,776	
Other comprehensive income					1,552		

Total comprehensive income							28,328
Preferred stock dividend						(318)	(318)
Conversion of preferred shares to common stock	(6)	13		(643)			(636)
Shares issued pursuant to employee benefit and option plan		1		(325)			(324)
Employee stock purchase plan				(33)			(33)
Tax benefits related to stock compensation plans				1,029			1,029
Restricted stock		2	2,018	(330)			1,690
Warrants		2		(2)			
Balances, December 31, 2005	$	$ 194	$ (3,334)	$ 220,360	$ (331)	$ 11,159	$ 228,048

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

Table of Contents

CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2005, 2004 and 2003
(In thousands)

	2005	2004	2003
Cash flows from operating activities:			
Net income (loss)	$ 26,776	$ 21,501	$ (17,991)
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	45,657	48,164	29,264
Accretion expense	3,549	3,400	2,884
Amortization of deferred financing costs	2,062	1,929	6,568
Non-cash loss on extinguishment of debt		2,910	4,423
Income from investment in Medusa Spar, LLC	(1,342)	(1,076)	
Cumulative effect of change in accounting principle			(181)
Non-cash derivative expense	1,635	(135)	487
Deferred income tax expense (benefit)	13,209	(6,697)	8,432
Non-cash charge related to compensation plans	1,906	1,225	858
Changes in current assets and liabilities:			
Accounts receivable, trade	(11,169)	(4,495)	(1,438)
Other current assets	670	971	(2,667)
Current liabilities	(8,666)	2,903	5,185
Change in gas balancing receivable	322	376	(340)
Change in gas balancing payable	(289)	400	(491)
Change in other long-term liabilities	(18)	(20)	(15)
Change in other assets, net	(292)	(448)	(349)
Cash provided by operating activities	74,010	70,908	34,629
Cash flows from investing activities:			
Capital expenditures	(73,072)	(64,649)	(50,705)
Distribution from Medusa Spar, LLC	463	339	24,908
Proceeds from sale of pipeline and other facilities			1,500
Proceeds from sale of mineral interests			982
Cash used by investing activities	(72,609)	(64,310)	(23,315)
Cash flows from financing activities:			
Change in accrued liabilities to be refinanced	5,000		(3,861)
Increase in debt	7,000	90,000	198,000
Payments on debt	(12,000)	(205,915)	(133,000)
Restricted cash		63,345	(63,345)
Debt issuance cost		(984)	(3,745)
Issuance of common stock	2	44,047	
Buyout of preferred stock	(637)		
Equity issued related to employee stock plans	(573)	199	127

Capital leases	(576)	(1,452)	(1,320)
Cash dividends on preferred stock	(318)	(1,272)	(1,277)
Cash used by financing activities	(2,102)	(12,032)	(8,421)
Net increase (decrease) in cash and cash equivalents	(701)	(5,434)	2,893
Cash and short-term investments:			
Balance, beginning of period	3,266	8,700	5,807
Balance, end of period	$ 2,565	$ 3,266	$ 8,700

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

Table of Contents

CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

General

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

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

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

Asset Retirement Obligations

In June 2001, the FASB issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143), effective for fiscal years beginning after June 15, 2002. SFAS 143 essentially requires entities to record the fair value of a liability for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Callon adopted SFAS 143 on January 1, 2003 resulting in a cumulative effect of accounting change of $181,000, net of tax. See Note 8.

Table of Contents

Oil and Gas Properties

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. 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 ($7.1 million in 2005, $7.2 million in 2004 and $8.4 million in 2003) do not include any costs related to production or general corporate overhead. Costs associated with unevaluated properties, including capitalized interest on such costs, are excluded from amortization. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties, the properties are sold or management determines that these costs have been impaired.

Costs of properties, including future development and future site restoration, dismantlement and abandonment costs, which have proved reserves and properties 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 accumulated amortization and deferred taxes relating to oil and gas properties, exceed the sum of (1) the estimated future net revenues from proved reserves at current prices 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 9.

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 available geological, engineering and regulatory data. 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. Until January 1, 2003, such costs were capitalized as oil and gas properties as the actual restoration, dismantlement and abandonment activities took place. As discussed above under Asset Retirement Obligations, beginning January 1, 2003, the Company changed the method for which we account for such costs upon adoption of SFAS 143 and these costs are now capitalized to the full cost pool when the related liabilities are incurred in accordance with the provisions of SFAS 143. In accordance with the SEC issued Staff Accounting Bulleting No. 106, assets recorded in connection with the recognition of an asset retirement obligation pursuant to SFAS 143 are included as part of the costs subject to the full-cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations are excluded from the computation of the present value of estimated future net revenues used in applying the ceiling test.

Property and Equipment

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. Depreciation expense of $227,000, $346,000 and $578,000 relating to other property and equipment was included in general and administrative expenses in the Company s statements of operations for the years ended December 31, 2005, 2004 and 2003, respectively. The accumulated depreciation on other property and equipment was $10.6 million and $10.4 million as of December 31, 2005 and 2004, respectively.

Table of Contents

Investment in Medusa Spar LLC

In December 2003, the Company announced the formation of a limited liability company, Medusa Spar LLC, which now owns a 75% undivided ownership interest in the deepwater spar production facilities on Callon s Medusa Field in the Gulf of Mexico. The Company contributed a 15% undivided ownership interest in the production facility to Medusa Spar LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC will earn a tariff based upon production volume throughput from the Medusa area. Callon is obligated to process our share of production from the Medusa Field and any future discoveries in the area through the spar production facilities. This arrangement allows Callon to defer the cost of the spar production facility over the life of the Medusa Field. The Company s cash proceeds were used to reduce the balance outstanding under its senior secured credit facility. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. On December 31, 2005, $47.0 million of the financing was outstanding. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. (NYSE:OII) and Murphy Oil Corporation (NYSE:MUR). The Company is accounting for our 10% ownership interest in the LLC under the equity method.

Natural Gas Imbalances

The Company follows the 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. Gas balancing receivables were $403,000 and $725,000 as of December 31, 2005 and 2004, respectively. Gas balancing payables were $304,000 and $594,000 as of December 31, 2005 and 2004, respectively.

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 are accounted for under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) as amended. See Note 6.

Income Tax

The Company follows the asset and liability method of accounting for deferred income taxes prescribed by Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). 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 will not be realized. See Note 3.

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 $66,000 and $103,000 at December 31, 2005 and 2004, respectively. Net charge offs recorded against the reserve for doubtful accounts were $37,000 in 2005 and zero in 2004. There were no provisions to expense in the three-year period ended December 31, 2005.

Table of Contents

Accrued Liabilities to be Refinanced

Amounts included in accrued liabilities to be refinanced represent capital expenditures that were refinanced with the availability under the Company s senior secured credit facility subsequent to the end of the year.

Major Customers

The Company s production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom it sold a significant percentage of its total oil and gas production during each of the years ended:

	December 31,		
	2005	**2004**	**2003**
Shell Trading Company	34%	30%	
Louis Dreyfus Energy Services	16%	23%	27%
Plains Marketing, L.P.	16%	13%	
Chevron Texaco Natural Gas	10%	6%	
Reliant Energy Services		6%	28%
Prior Energy Corporation			20%

Because alternative purchasers of oil and gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on its 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 in the period ended December 31, 2005. During the years ended December 31, 2005, 2004 and 2003, the Company made cash payments for interest of $19,854,000, $23,197,000 and $27,913,000, respectively.

Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 123 (revised 2004), Share-Based Payment (SFAS 123R), which is a revision of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123). SFAS 123R supersedes APB Opinion No. 25, Accounting for Stock Issued to Employees , and amends Statement of Financial Accounting Standards No. 95, Statement of Cash Flows. Generally, the approach in SFAS 123R is similar to the approach described in SFAS 123. However, SFAS 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the income statement based on their fair values. Pro forma disclosure is no longer an alternative.

In April 2005, the Securities and Exchange Commission (SEC) delayed the effective date of SFAS 123R for public companies to no later than the beginning of the first fiscal year beginning after June 15, 2005. Early adoption is permitted in periods in which financial statements have not yet been issued. SFAS 123R permits public companies to adopt its requirements using one of two methods below:

Table of Contents

- A modified prospective method in which compensation cost is recognized beginning with the effective date (a) based on the requirements of SFAS 123R for all share-based payments granted after the effective date and (b) based on the requirements of SFAS 123 for all awards granted to employees prior to the effective date of SFAS 123R that remain unvested on the effective date; or

- A modified retrospective method which includes the requirements of the modified prospective method described above, but also permits entities to restate based on the amounts previously recognized under SFAS 123 for purposes of pro forma disclosures either (a) all prior periods presented or (b) prior interim periods of the year of adoption.

As permitted by SFAS 123, through December 31, 2005, the Company accounted for share-based payments to employees using APB Opinion 25 s intrinsic value method and, as such, generally recognized no compensation cost for employee stock options. Accordingly, the adoption of SFAS 123R s fair value method could have a significant impact on our result of operations, although it will have no impact on our overall financial position. The impact of SFAS 123R cannot be predicted at this time because it will depend on levels of share-based payments granted in the future. However, had we adopted SFAS 123R in prior periods, the impact of that standard would have approximated the impact of SFAS 123 as described in the disclosure of pro forma net income and earnings per share below under Stock-Based Compensation. The Company adopted SFAS 123R on January 1, 2006 using the modified prospective method.

Stock-Based Compensation

The Company s pro forma net income (loss) and net income (loss) per share of common stock for the years ended December 31, 2005, 2004 and 2003 had compensation costs been recorded using the fair value method in accordance with SFAS 123, as amended by Statement of Financial Accounting Standards No. 148, Accounting for Stock-Based Compensation-Transition and Disclosure-an amendment of SFAS No. 123 (SFAS 148), are presented below pursuant to the disclosure requirements of SFAS 148 (in thousands except per share data):

	2005	**2004**	**2003**
	(In thousands, except per share data)		
Net income (loss) available to common shares, as reported	$ 26,458	$ 20,229	$ (19,268)
Stock-based compensation expense included in net income as reported, net of tax	1,313	348	17
Deduct: Total stock-based compensation expense under fair value based method, net of tax	(1,497)	(549)	(247)
Pro forma net income (loss) available to common shares	$ 26,274	$ 20,028	$ (19,498)
Basic earnings (loss) per share: As Reported	1.43	1.28	(1.41)
Pro Forma	1.42	1.27	(1.43)
Diluted earnings (loss) per share: As Reported	1.28	1.22	(1.41)
Pro Forma	1.27	1.20	(1.43)

See Note 11 for descriptions and additional disclosures related to the stock incentive plans.

Table of Contents

Per Share Amounts

Basic income or loss per common share was computed by dividing net income or loss by the weighted average number of shares of common stock outstanding during the year. Diluted income or loss per common share was determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options considered common stock equivalents computed using the treasury stock method and the effect of the convertible preferred stock (if dilutive). The conversion of the preferred stock was not included in the annual calculation for 2003 due to its antidilutive effect on diluted income or loss per common share. In addition, below are the shares relating to stock options, warrants and restricted stock that were not included in diluted shares for the year ended December 31, 2003 due to the fact that the Company had a loss for this period. The Company had net income for the years ended December 31, 2005 and 2004 and all such shares were included as described below.

	Twelve Months Ended December 31, (in thousands) 2003
Stock options	63
Warrants	424
Restricted Stock	248

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

	2005	2004	2003
(a) Net income (loss) available to common shares	$ 26,458	$ 20,229	$ (19,268)
Preferred dividends assuming conversion of preferred stock(if dilutive)	318	1,272	
(b) Income (loss) available to common shares assuming conversion of preferred stock (if dilutive)	$ 26,776	$ 21,501	$ (19,268)
(c) Weighted average shares outstanding	18,453	15,796	13,662
Dilutive impact of stock options	348	233	
Dilutive impact of restricted stock	69	75	
Dilutive impact of warrants	1,375	894	
Convertible preferred stock (if dilutive)	638	680	
(d) Total diluted shares	20,883	17,678	13,662
Stock options and warrants excluded due to the exercise price being greater than the stock price	1	89	2,297
Basic income (loss) per share (a¸c)	$ 1.43	$ 1.28	$ (1.41)
Diluted income (loss) per share (b¸d)	$ 1.28	$ 1.22	$ (1.41)

Table of Contents

Fair Value of Financial Instruments

Fair value of cash, cash equivalents, accounts receivable, accounts payable, the capital lease and the senior secured credit facility approximates book value at December 31, 2005 and 2004. Fair value of long-term debt (specifically, the 9.75% Senior Notes) had an estimated fair value of 103% of face value at December 31, 2005.

3. INCOME TAXES

The Company had a net current asset of $26.8 million and a net long-term liability of $31.6 million resulting in a net deferred tax liability of $4.8 million at December 31, 2005. At December 31, 2004, the Company had a net current asset of $5.7 million and a net long-term asset of $3.0 million resulting in a net deferred tax asset of $8.7 million. Below is an analysis of the net deferred tax asset (liability) as of December 31, 2005 and 2004.

	December 31,	
	2005	**2004**
	(In thousands)	
Deferred Tax Asset:		
Federal net operating loss carryforwards	$ 58,240	$ 56,271
Statutory depletion carryforward	4,443	4,124
Alternative minimum tax credit carryforward	547	326
SFAS 143-Asset Retirement Obligations	11,307	11,544
Other	1,389	2,786
Total deferred tax asset	75,926	75,051
Deferred Tax Liability:		
Difference between book and tax basis for property	(80,565)	(66,277)
Other	(224)	(112)
Total deferred tax liability	(80,789)	(66,389)
Net deferred tax asset (liability)	$ (4,863)	$ 8,662

If not utilized, the Company s federal net operating loss carryforwards will expire in 2013 through 2020. 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.

SFAS 109 provides for the weighing of positive and negative evidence in determining whether it is more likely than not that a deferred tax asset is recoverable. The Company achieved profitable operations in 2005 and 2004 and had income on an aggregate basis for the three-year period ended December 31, 2005. In addition, we expect 2006 production levels to meet or exceed 2005 levels. As a result, the Company has not provided a valuation allowance as of December 31, 2005.

Table of Contents

The Company incurred losses in 2002 and 2003 and had losses on an aggregate basis for the three-year period ended December 31, 2003. Because of these cumulative losses the Company established a full valuation allowance of $11.5 million as of December 31, 2003. For the three-year period ended December 31, 2004, the Company had income on an aggregate basis resulting from the Company achieving profitable operations in 2004 due to the Company s first two deepwater projects starting in November 2003 and the refinancing of the Company s highest cost debt. As a result, the Company reversed the valuation allowance, which had a balance of $7.0 million, as of December 31, 2004.

Below is a reconciliation of the reported amount of income tax expense attributable to continuing operations for the year to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations.

	Year Ended December 31,		
	2005	**2004**	**2003**
Income tax expense (benefit) computed at the statutory federal income tax rate	35%	35%	(35%)
Change in valuation allowance		(84)%	118%
Other	(1%)		4%
Effective income tax rate	34%	(49)%	87%

4. OTHER COMPREHENSIVE INCOME

The Company s other comprehensive income (loss) of $1.6 million, $(1.9 million) and $449,000 for the years ended December 31, 2005, 2004 and 2003 respectively, relates to the change in fair value of its derivatives (other comprehensive income (loss) was net of tax of $835,000, $1.0 million and $242,000 for the years ended December 31, 2005, 2004 and 2003, respectively). See Note 6.

Table of Contents

5. LONG-TERM DEBT

Long-term debt consisted of the following at:

	December 31, 2005	December 31, 2004
	(In thousands)	
Senior Secured Credit Facility	$	$ 5,000
9.75% Senior Notes (due 2010) net of discount	187,941	186,216
Capital Lease	1,135	1,711
Total Long-term Debt	189,076	192,927
Less current portion	263	576
Long-term portion	$ 188,813	$ 192,351

Senior Secured Credit Facility. On June 15, 2004, the Company closed on a three-year senior secured credit facility underwritten by Union Bank of California, N.A. (Union Bank) to replace the Company s credit facility with Wachovia Bank, National Association (Wachovia Bank) which was expiring June 30, 2004. The credit facility had an initial borrowing base of $60 million, which was increased to $70 million in the second quarter of 2005. The borrowing base is reviewed and redetermined semi-annually and can be increased to a maximum of $175 million. Borrowings under the credit facility are secured by mortgages covering the Company s five largest fields. The credit facility bears interest at 0.25% above a defined base rate depending on utilization of the borrowing base or, at the option of the Company, LIBOR plus 1.5% to 2.25% based on utilization of the borrowing base. Under the senior secured 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 range of interest rates on the senior secured credit facility was 4.16% to 6.00% for the year ended December 31, 2005. The weighted average interest rate for the debt outstanding under the senior secured credit facility at December 31, 2004 was 4.16%. As of December 31, 2005 there were no borrowings outstanding under the facility; however, Callon had an aggregate of $7.5 million in outstanding letters of credit issued under the credit facility. These letters of credit secure obligations under the outstanding hedging contracts described in Note 6. The outstanding letters of credit reduce the amount available for borrowings under the credit facility. As a result, $62.5 million was available for future borrowings under the credit facility as of December 31, 2005.

Certain of the Company s subsidiaries guarantee the Company s obligations under the $200 million 9.75% Senior Notes due 2010. The subsidiary guarantors are 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantors are minor.

Restructured Debt. In December 2003 and in the first half of 2004, the Company completed several transactions which restructured all debt that was maturing through 2005. A summary of these transactions is as follows:

- borrowing $185 million pursuant to a senior unsecured credit facility for a term of seven years at an interest rate of 9.75% in December 2003;
- the formation of Medusa Spar LLC in which the Company contributed its 15% ownership in the deepwater spar production facilities in return for a 10% interest in Medusa Spar LLC and approximately $25 million in cash;
- borrowing an additional $15 million for a term of seven years at an interest rate of 9.75% pursuant to a senior unsecured credit agreement in the first quarter of 2004;
- closing a three-year senior secured credit facility with an initial borrowing base of $60 million in June 2004 which can be increased by the lender to $175 million; and
- closing the public offering of 3,450,000 shares of common stock priced at $13.25 per share raising net proceeds of approximately $44 million, after expenses, in June 2004.

Below is a list of the debt which was extinguished and restructured with the funds raised from the transactions above.

- the Company s $22.9 million, 10.125% senior subordinated notes due in 2004
- the Company s $40 million, 10.25% senior subordinated notes due in 2004
- the Company s $95 million, 12% senior unsecured credit facility due in 2005
- the Company s $33 million, 11% senior subordinated notes due in 2005

All of the above debt was extinguished before maturity which resulted in a loss on early extinguishment of debt for the years ended December 31, 2004 and 2003 of $3.0 million and $5.6 million, respectively. In addition to restructuring the Company s debt, Callon reduced the balance outstanding on its senior secured credit facility.

9.75% Senior Notes (due 2010). In December 2003 the Company borrowed $185 million pursuant to a senior unsecured credit facility. The loans under the credit facility have a stated interest rate of 9.75% and a seven-year maturity. The net proceeds of $181.3 million were used to redeem $22.9 million of 10.125% senior subordinated notes due July 31, 2004, $40 million of 10.25% senior subordinated notes due September 15, 2004 and $85 million of our 12% senior loans due March 31, 2005 plus a 1% pre-payment premium of $850,000, and to reduce the balance outstanding under the Company s senior secured credit facility. In conjunction with the new senior unsecured notes, the Company issued detachable warrants to purchase 2.775 million shares of it s common stock at an exercise price of $10 per share and an expiration date of December 2010. The warrants were valued at $10.6 million and were treated as a discount on the debt. This senior unsecured debt matures December 8, 2010 and has an effective interest rate of 11.4%. The Company recorded the issuance of these new securities at a fair value of $171 million. Deferred costs of $14 million associated with the notes will be amortized over the life of the notes.

During March 2004, Callon borrowed an additional $15 million under its 9.75% senior unsecured credit facility bringing the total outstanding under the facility to $200 million. The net proceeds of approximately $14 million were primarily used to retire the remaining $10 million of 12% senior loans due March 31, 2005 plus a 1% call premium of $100,000. The Company recorded the issuance of these additional new securities at a fair value of $14 million. Deferred costs of $1 million associated with the notes will be amortized over the life of the notes.

Table of Contents

In March 2004, the $200 million in aggregate principal amount of loans outstanding under the 9.75% senior unsecured credit facility were exchanged for 9.75% Senior Notes due 2010, Series A, Series A notes , issued pursuant to a senior indenture between Callon and American Stock Transfer & Trust Company dated March 15, 2004. On August 12, 2004, the Company completed an offer to exchange its 9.75% Senior Notes due 2010, Series B, that have been registered under the Securities Act of 1933, for all outstanding Series A notes.

In December 2005, 79,500 of the detachable warrants issued with the 9.75% Senior Notes due 2010 were exercised. In addition, 265,210 of $0.01 warrants associated with the 12% senior unsecured credit facility due in 2005 were outstanding as of December 31, 2005.

Capital Lease. In December 2001, the Company entered into a 10-year gas processing agreement associated with a production facility on Callon s Mobile Block 952 Field with Hanover Compression Limited Partnership, which is being accounted for as a capital lease. Total minimum obligations are $8.4 million with interest representing approximately $2.8 million and the present value minimum obligations representing $5.6 million.

Restrictive Covenants. The Indenture governing our 9.75% senior notes due 2010 and our senior secured credit facility contains various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, our senior secured credit facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2005.

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

Year	Capital Lease Payments	Debt
2006	$ 439	$
2007	348	
2008	228	
2009	229	
2010	220	200,000
Thereafter	245	

Table of Contents

6. DERIVATIVES

The Company periodically uses derivative financial instruments to manage oil and gas price risk. Settlements of gains and losses on commodity price contracts are generally based upon the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price.

The Company s derivative contracts that are accounted for as cash flow hedges under SFAS 133 are recorded at fair market value and the changes in fair value are recorded through other comprehensive income (loss), net of tax, in stockholders equity. The cash settlements on these contracts are recorded as an increase or decrease in oil and gas sales. The changes in fair value related to ineffective derivative contracts are recognized as derivative expense (income). The cash settlement on these contracts is also recorded within derivative expense (income). The changes in fair value of the Company s derivative contracts that are not designated as effective cash flow hedges are recorded through the statement of operations as derivative expense (income).

Cash settlements on effective cash flow hedges for the years ended December 31, 2005, 2004 and 2003 resulted in a reduction of oil and gas sales in the amount of $10.3 million, $13.8 million and $2.9 million, respectively. Cash settlements on ineffective derivative contracts were recorded as derivative expense in the amount of $4.4 million and $1.2 million for the years ended December 31, 2005 and 2004, respectively. These contracts were deemed ineffective as a result of a shortfall in production volumes due to downtime from the tropical storm activity in the third quarters of 2005 and 2004 impacting third and fourth quarter production volumes for the respective years.

The following table summarizes derivative expense for the periods presented (in thousands):

	December 31,		
	2005	**2004**	**2003**
Amortization of derivative contract premiums	$ 1,634	$	$
Change in fair value and settlements of ineffective derivative contracts	4,394	1,209	
Change in fair value and settlements of non-designated derivative contracts		162	535
	$ 6,028	$ 1,371	$ 535

58

Table of Contents

The Company had a current liability of $1.2 million and a current asset of $889,000 relating to the fair value of its respective derivative contracts as of December 31, 2005.

Listed in the table below are the outstanding derivative contracts as of December 31, 2005:

Swaps

Product	Volumes per Month	Quantity Type	Average Price	Period
Oil	15,000	Bbls	$ 55.00	01/06-06/06

Collars

Product	Volumes per Month	Quantity Type	Average Floor Price	Average Ceiling Price	Period
Oil	30,000	Bbls	$60.00	$77.10	01/06-12/06
Natural Gas	200,000	MMBtu	$10.00	$16.00	01/06-03/06
Natural Gas	100,000	MMBtu	$ 8.33	$11.93	01/06-09/06

7. COMMITMENTS AND CONTINGENCIES

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

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

The Company s Medusa deepwater property is eligible for royalty suspensions pursuant to the Deep Water Royalty Relief Act. In addition, the Company has several shallow water, deep natural gas properties and prospects that are eligible for royalty suspensions. However, the federal offshore leases covering these properties contain price threshold provisions for oil and gas prices. Under these price threshold provisions, if the average monthly New York Mercantile Exchange (NYMEX) sales price for oil or gas during a fiscal year exceeds the price threshold for oil or gas, respectively, then royalties on the associated production must be paid to the Minerals Management Service (MMS) at the rate stipulated in the lease. The price thresholds are adjusted annually by the implicit price deflator for the GDP. The determination of whether or not royalties are due as a result of the average NYMEX price exceeding the price threshold is made during the first quarter of the succeeding year. Any royalty payments due must be made shortly after this determination is made. If a royalty payment is due for all production during a year as a result of exceeding the price threshold, the lessee is required to make monthly royalty payments during the succeeding fiscal year for the succeeding year s production. If at the end of any year the average NYMEX price is below the price threshold, the lessee can apply for a refund for any associated royalties paid during that year and the lessee will not be required to pay royalties monthly during the succeeding year for the succeeding year s production.

Table of Contents

The thresholds and actual average NYMEX for 2005 are in the table below.

	2005	
	Threshold	Actual Average NYMEX
Deepwater Oil Prices ($/bbl)	34.73	56.57
Deepwater Natural Gas Prices ($/mmbtu)	4.34	8.96
Shallow Water, Deep Natural Gas Prices ($/mmbtu)	9.60	8.96

The Company was required to make monthly royalty payments for 2005 deepwater oil and gas production and will be required to make monthly royalty payments for 2006. With regard to the shallow water, deep natural gas royalty relief, the Company will not be required to make monthly royalty payments for 2006.

In the year succeeding the year in which any of the Company s properties became subject to royalties as the result of the average NYMEX price exceeding the price threshold, the portion of reserves attributable to potential future royalties would not be included in a year-end reserve report. However, if the average NYMEX prices were below the price thresholds in subsequent years, our reserves would be increased to reflect reserves previously attributed to future royalties. As a result, reported oil and gas reserves could materially increase or decrease, depending on the relation of price thresholds versus the average NYMEX prices. The reduction in revenues resulting from an obligation to pay these royalties and subsequent reduction of proved reserves could have a material adverse effect on the Company s results of operations and financial condition. The Company s reserve report as of December 31, 2005 excluded oil and gas reserves for Medusa that are subject to MMS royalties as a result of the average 2005 NYMEX prices for oil and gas exceeding the price thresholds.

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

8. ASSET RETIREMENT OBLIGATIONS

As discussed in Note 2, the Company adopted SFAS 143 on January 1, 2003. The impact of adopting the statement resulted in a gain of $181,000, net of tax, which was reported as a cumulative effect of change in accounting principle. Approximately $30.3 million was recorded as the present value of asset retirement obligations on January 1, 2003 with the adoption of SFAS 143 related to the Company s oil and gas properties. Interest is accreted on this amount and reported as accretion expense in the Consolidated Statements of Operations.

Table of Contents

Assets, primarily short-term U.S. Government securities, of approximately $6.0 million at December 31, 2005, of which $4.1 million was current, was recorded as restricted investments. These assets are held in abandonment trusts (Trusts) dedicated to pay future abandonment costs of oil and gas properties in which the Company has sold a net profit interest (NPI). In September 2005, Callon purchased the NPI s which included the Trusts. See Note 10 to the Consolidated Financial Statements for more detail on the NPI transaction.

The following table summarizes the activity for the Company s asset retirement obligations:

	Twelve Months Ended	
	December 31, 2005	**December 31, 2004**
Asset retirement obligations at beginning of period	$ 38,282	$ 33,691
Accretion expense	3,549	3,400
Net profits interest accretion	331	459
Liabilities incurred	2,365	3,065
Liabilities settled	(5,184)	(2,076)
Revisions to estimate	(1,070)	(257)
Asset retirement obligation at end of period	38,273	38,282
Less: current retirement obligations	(21,660)	(13,300)
Long-term retirement obligations	$ 16,613	$ 24,982

Table of Contents

9. 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.

	Years Ended December 31,		
	2005	2004	2003
	(In thousands)		
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 862,101	$ 802,912	$ 762,918
Property acquisition costs	6,627	1,355	1,154
Exploration costs	46,379	26,749	21,390
Development costs	26,481	32,004	33,972
SFAS 143-Asset Retirement Obligation	(3,890)	(918)	18,002
Medusa Spar transaction			(33,542)
Sale of mineral interests		(1)	(982)
End of period balance	$ 937,698	$ 862,101	$ 802,912
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 39,042	$ 34,251	$ 40,997
Additions	18,739	16,367	5,228
Capitalized interest	5,655	4,577	4,862
Transfers to evaluated	(14,371)	(16,153)	(16,836)
End of period balance	$ 49,065	$ 39,042	$ 34,251
Accumulated depreciation, depletion and amortization-			
Beginning of period balance	$ 494,453	$ 447,000	$ 426,254
Provision charged to expense	44,946	47,453	28,195
Cumulative effect of change in accounting Principle			(7,449)
End of period balance	$ 539,399	$ 494,453	$ 447,000

Unevaluated property costs, primarily lease acquisition costs incurred at federal and state lease sales, unevaluated drilling costs, capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base, consisted of $18.8 million incurred in 2005, $7.8 million incurred in 2004 and $22.5 million incurred in 2003 and prior. These costs are directly related to the acquisition and evaluation of unproved properties and major development projects. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The Company expects that the majority of these costs will be evaluated over the next three to five-year period.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $2.39, $2.18 and $2.03 for the years ended December 31, 2005, 2004, and 2003, respectively.

Table of Contents

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

10. 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 were in the form of NPI s equal to a significant percentage of the excess of gross proceeds over costs, as defined by the agreements, from the acquired oil and gas properties. In September 2005, the Company purchased the NPI s for $5 million before intervening operations. Included in the transaction were the Trusts which were established at the inception of the NPI s for future plugging and abandonment liabilities.

The Company, pursuant to the purchase agreements, created the Trusts (see Note 8) 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 disbursement of funds to 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 Callon. Estimated future revenues and costs associated with the Trusts are also excluded from the oil and gas reserve disclosures at Note 13. As of December 31, 2005 and 2004, the Trusts assets (all cash and investments) totaled $6.0 million and $7.7 million respectively, all of which will be available to the Company to pay the restoration, dismantlement and abandonment costs. SFAS 143, discussed in Note 2 and 8, does not allow the Trusts assets to be used to offset the associated abandonment liability. The Company did not record any income or loss associated with the Trust asset or abandonment liability as a result of adoption of SFAS 143.

Table of Contents

11. 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:

Savings and Protection Plan

The Savings and Protection Plan (401-K 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 401-K 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 401-K Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $557,000, $528,000 and $562,000 in the years 2005, 2004 and 2003, respectively.

1994 Stock Incentive Plan

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

1996 Stock Incentive Plan

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

The Company granted 533,000 stock options to employees on March 23, 2000 and 120,000 stock options to directors on July 25, 2000 at $10.50 per share. The March 23, 2000 grant was subject to shareholder approval of an amendment to the 1996 Stock Incentive Plan. The amendment, which was approved on May 9, 2000 at the Annual Meeting of Shareholders, increased the number of shares reserved for issuance under the 1996 plan to 2,200,000 shares. The excess of the market price over the exercise price on the approval date of the amendment was amortized over the three-year vesting period of the options. Compensation costs of $27,000 were recognized in 2003, related to these options.

In 2004, the Company awarded 455,000 performance shares from the 1994 and 1996 Plans. These shares vest to the recipients over a five-year period (one-fifth in each year) beginning in July 2005. The deferred compensation portion of this grant will be amortized to expense over the vesting period. The non-cash amortization expense in 2005 and 2004 was $1,029,000 and $532,000, respectively. In 2005, an additional non-cash expense of $989,000 was recognized for accelerated vesting of performance shares for an executive officer and two directors of the Company, two of whom are deceased, and the retirement of an employee.

2002 Stock Incentive Plan

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

In 2002, the Company awarded 300,000 shares of restricted stock from the 1996 and the 2002 Plan and 70,500 from treasury shares to be issued as vested. The issuance of the restricted stock using treasury shares did not require shareholder approval pursuant to the New York Stock Exchange s rules and regulations, and therefore shareholder approval was not sought. These shares vested to the recipients over a three-year period (one-third in each year) beginning in November 2002. The deferred compensation portion of this grant was amortized to expense over the vesting period. The non-cash amortization expense in 2004 and 2003 was $374,000 and $454,000, respectively.

Employee Stock Purchase Plan

In 1997, the Board of Directors authorized the implementation of the Callon Petroleum Company 1997 Employee Stock Purchase Plan (the 1997 ESPP), which was approved by the Company s shareholders at the 1997 Annual Meeting. The 1997 ESPP provided eligible employees of the Company with the opportunity to acquire a proprietary interest in the Company through participation in a payroll deduction-based employee stock purchase plan. An aggregate of 250,000 shares of common stock were reserved for issuance over the10-year term of the 1997 ESPP. The purchase price per share at which common stock was purchased on the participant s behalf on each purchase date within an offering period was equal to 85 percent of the fair market value per share of common stock. As of December 31, 2004 there were no remaining shares available for purchase.

Table of Contents

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

	2005		2004		2003	
	Shares	**Wtd Avg Ex Price**	**Shares**	**Wtd Avg Ex Price**	**Shares**	**Wtd Avg Ex Price**
Outstanding, beginning of year	1,512,599	$ 9.93	2,450,867	$ 9.84	2,520,417	$ 9.90
Granted (at market)	65,000	15.79	25,000	12.40	30,000	5.12
Exercised	(329,441)	10.34	(437,918)	9.74	(500)	4.10
Forfeited			(525,350)	9.80	(99,050)	9.74
Expired	(42,600)	10.60				
Outstanding, end of year	1,205,558	$ 10.11	1,512,599	$ 9.93	2,450,867	$ 9.84
Exercisable, end of year	1,166,558	$ 9.88	1,446,486	$ 10.20	2,262,067	$ 10.31
Weighted average fair value of options granted (at market)	$ 5.93		$ 4.48		$ 2.97	

The following table sets forth additional information regarding options outstanding at December 31, 2005. Contractual life and exercise prices represent weighted averages for options outstanding and options exercisable.

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number Outstanding	Contractual Life (years)	Exercise Price	Number Exercisable	Exercise Price
$3.70 to $6.41	185,308	6.6	$ 4.48	185,308	$ 4.48
$9.00 to $12.40	905,250	3.1	$10.64	905,250	$10.64
$13.56 to $19.72	115,000	6.4	$15.67	76,000	$14.11

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

	2005	**2004**	**2003**
Risk free interest rate	4.3%	3.7%	4.0%
Expected life (years)	4.5	5.0	5.0
Expected volatility	37.5%	45.1%	65.3%
Expected dividends			

Table of Contents

12. EQUITY TRANSACTIONS

On June 13, 2005, Callon called for redemption all of the Company s outstanding shares of $2.125 Convertible Exchange Preferred Stock, Series A. A notice of redemption and letter of transmittal was mailed to all holders of record as of the close of business on June 10, 2005. Between June 13, 2005 and June 30, 2005, 180,173 shares of preferred stock were converted into 409,496 shares of the Company s common stock. Subsequent to June 30, 2005, 392,935 shares of preferred stock were converted into 893,076 shares of the Company s common stock. In addition, 23,563 shares of the Company s preferred stock were redeemed for $606,000 on July 14, 2005. As a result of the redemption, we will benefit from an annual cash savings of $1.3 million in dividend payments.

On June 22, 2004, we closed the public offering of three million shares of common stock priced at $13.25 per share raising net proceeds of approximately $38.2 million, after expenses. In addition, we granted the underwriter, Johnson Rice & Company L.L.C., an over-allotment option to purchase an additional 450,000 shares. On June 30, 2004, the underwriter exercised the over-allotment option for an additional 450,000 shares priced at $13.25 per share, raising the net proceeds of the offering by approximately $5.7 million, after expenses. The proceeds from the transactions were used to redeem $33 million of the 11% Senior Subordinated Notes due December 15, 2005 and for general corporate purposes.

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.

13. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company s proved oil and gas reserves at December 31, 2005, 2004 and 2003 have been estimated by Huddleston & Co., Inc. who are the Company s independent petroleum consultants. The reserves were prepared 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.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only and should not be construed as being exact. In addition, the standardized measure of discounted future net cash flows should not be construed as the current market value of the Company s oil and gas properties or the cost that would be incurred to obtain equivalent reserves. See Note 7 regarding the Deep Water Royalty Relief Act and the loss of reserves.

Table of Contents

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

	Years Ended December 31,		
	2005	**2004**	**2003**
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	19,748	23,709	24,043
Revisions to previous estimates	316	(2,370)(a)	(1)
Purchase of reserves in place	71		
Sales of reserves in place			(65)
Extensions and discoveries	129	145	
Production	(1,836)	(1,736)	(268)
End of period	18,428	19,748	23,709
Natural Gas (MMcf):			
Beginning of period	72,619	74,691	91,539
Revisions to previous estimates	(4,946)	2,138	(6,407)(a)
Purchase of reserves in place	1,308		
Sales of reserves in place			(49)
Extensions and discoveries	16,808	7,177	1,923
Production	(7,768)	(11,387)	(12,315)
End of period	78,021	72,619	74,691
Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	10,292	9,919	1,056
End of period	7,323	10,292	9,919
Natural Gas (MMcf):			
Beginning of period	33,982	31,415	37,631
End of period	30,982	33,982	31,415

(a) Includes Medusa royalty adjustment

Table of Contents

Standardized Measure

The following tables present the Company s standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves and were computed using reserve valuations based on regulations prescribed by the SEC. These regulations provide that the oil, condensate and gas price structure utilized to project future net cash flows reflects current prices (approximately $10.13 per Mcf for natural gas and $55.44 per Bbl for oil for the 2005 disclosures, $6.51 per Mcf and $36.72 per Bbl for 2004 disclosures, and $5.99 per Mcf and $30.50 per Bbl for 2003 disclosures) at each date presented and have not been escalated. Future production and development 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

	Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Future cash inflows	$ 1,814,208	$ 1,198,096	$ 1,170,118
Future costs			
Production	(238,321)	(231,616)	(219,421)
Development and net abandonment	(88,070)	(74,335)	(111,850)
Future net inflows before income taxes	1,487,817	892,145	838,847
Future income taxes	(379,287)	(166,284)	(89,567)
Future net cash flows	1,108,530	725,861	749,280
10% discount factor	(270,978)	(209,968)	(230,254)
Standardized measure of discounted future net cash flows	$ 837,552	$ 515,893	$ 519,026

Changes in Standardized Measure

	Years Ended December 31,		
	2005	2004	2003
		(In thousands)	
Standardized measure beginning of period	$ 515,893	$ 519,026	$ 556,046
Sales and transfers, net of production costs	(116,913)	(97,494)	(62,396)
Net change in sales and transfer prices, net of production costs	391,570	86,551	(41,011)
Exchange and sale of in place reserves			(1,226)
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs incurred	127,848	77,576	25,632
Revisions of quantity estimates	(17,241)	(41,314)	(18,018)
Accretion of discount	61,259	57,046	62,394
Net change in income taxes	(154,460)	(45,262)	16,460
Changes in production rates, timing and other	29,596	(40,236)	(18,855)
Standardized measure end of period	$ 837,552	$ 515,893	$ 519,026

Table of Contents

14. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

2005		First Quarter	Second Quarter	Third Quarter(a)	Fourth Quarter(a)
		(In thousands, except per share data)			
Total revenues		$43,012	$41,668	$31,722	$24,888
Income from operations		18,134	17,696	8,692	9,783
Net income		9,475	9,311	3,683	4,307
Net income per common share	basic	$ 0.52	$ 0.52	$ 0.19	$ 0.22
Net income per common share	diluted				