CALLON PETROLEUM CO
Form 10-K
March 16, 2007

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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, 2006
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 $384.5 million as of June 30, 2006 (based on the last reported sale price of such stock on the New York Stock Exchange on such date of $19.34).

As of March 5, 2007, there were 20,750,449 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, 2007) relating to the Annual Meeting of Stockholders to be held on May 3, 2007, which are incorporated into Part III of this Form 10-K.

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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 unl 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 11 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, 2006, we owned working interests in a total of 112 blocks/leases covering 223,000 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. We have 8,000 square miles of 3-D seismic data and have invested in pre-stack time migration in order to apply AVO de-risking to our prospects. 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 2006 with estimated net proved reserves of 145.6 billion cubic feet of natural gas equivalent (Bcfe). This represents a decrease of 23% from 2005 year-end estimated net proved reserves of 188.6 Bcfe.

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

Availability of Reports

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

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, and onshore Louisiana;
- aggressively explore our existing prospect inventory;
- replenish our prospect inventory with increasing emphasis on prospect generation using AVO technology to reduce the risks associated with our exploratory drilling; and
- acquire producing properties with infrastructure in areas of focus that contain upside potential.

Exploration and Development Activities

In 2006, capital expenditures for exploration and development costs related to oil and gas properties totaled approximately $167 million. These expenditures included:

- $107 million in the Gulf of Mexico shelf, onshore south Louisiana and Texas State waters areas which included the drilling of 10 exploratory wells, five of which were unsuccessful, two development wells and completion costs for our successful wells;
- $15 million in our deepwater area, which included four exploratory wells, three of which were unsuccessful and one temporarily abandoned;
- $16 million for leasehold and seismic costs;
- $13 million for plugging and abandonment costs; and
- $6 million for capitalized interest and $10 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.

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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 Mineral Management Services (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.

Our Entrada field is governed by leases from the MMS. These leases granted royalty suspension without provisions for pricing thresholds for crude oil and natural gas which would require us to pay royalties to the MMS if the thresholds were exceeded by the current year average of NYMEX prices. The MMS has notified us the exclusion of the provisions occurred in error in the lease issuance process and was not the MMS s intention. Congress is considering various bills to address this issue and if a bill were to pass to amend the leases to provide thresholds for crude oil and natural gas prices the reserves for Entrada could be subject to royalties. However, the MMS stated in their correspondence to us they will continue to honor the terms of the leases as issued unless notified otherwise. This correspondence applies only to our 20% working interest in the Entrada field.

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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, 2006, approximately 57% of the discounted present value of our estimated net proved reserves were proved undeveloped. Proved undeveloped reserves represented 54% 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.

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 2006, approximately 80% of our daily production came from eight of our properties in the Gulf of Mexico. Moreover, one property accounted for 40% of our production during this period. In addition, at December 31, 2006, most of our proved reserves were located in three fields in the Gulf of Mexico, with approximately 72% 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

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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.

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:

- 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 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources and Note 7 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

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weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Offshore operations are also subject to more extensive governmental regulation.

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

We may not have production to offset hedges; by hedging, we may not benefit from price increases. Part of our business strategy is to reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged. We are required to pay the difference between the floating price and the fixed price when the floating price exceeds the fixed price regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge. 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 measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or 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.

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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 Officers, do 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

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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.

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**.**

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Employees

We had 86 employees as of December 31, 2006, none of whom are currently represented by a union. We believe that we have good relations with our employees. We employ six petroleum engineers and eight 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.

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 wastes, 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 and we could be required to cleanup or mitigate the environmental impacts of unauthorized discharges. 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 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 regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect 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.

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, 2006, our estimated net proved reserves totaled 145.6 Bcfe and included 13.3 million barrels of oil (MMBbl) and 66.0 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 $534.7 million. Oil constitutes approximately 55% on an equivalent basis of our total estimated proved reserves and approximately 46% 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 50% of our total production during 2006.

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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, 2006.

	Operator	Estimated Net Proved Reserves Oil (MBbls)	Gas (MMcf)	Total (MMcfe)	Pre-tax Discounted Present Value ($000) (a)(b)(c)
Gulf of Mexico Deepwater:					
Garden Banks Block 738/782/826/827					
Entrada	BP	3,824	19,059	42,003	$ 134,977
Mississippi Canyon 538/582					
Medusa	Murphy	6,030	4,139	40,319	156,542
Garden Banks Block 341					
Habanero	Shell	2,582	6,252	21,747	121,909
Gulf of Mexico Shelf and Onshore:					
High Island Blocks 165/130	Hydro GOM	48	9,594	9,880	37,687
West Cameron 3/LA	Callon	100	3,393	3,992	17,919
High Island Block A-540	Walter Oil & Gas Corp.	104	3,063	3,686	16,514
West Cameron Block 295	Hydro GOM/Cimarex	12	4,679	4,751	15,990
North Padre Island Block 913	Callon		1,874	1,878	7,834
East Cameron Block 109	Energy Partners LTD	48	1,592	1,879	7,515
Other	Various	517	12,392	15,493	17,856
Total Net Proved Reserves		13,265	66,037	145,628	$ 534,743

(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, 2006, 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, 2006, 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.

(c) We use the financial measure present value of estimated future net revenues from proved reserves, excluding income taxes. This is a non-GAAP financial measure. We believe that present value of estimated future net revenues from proved reserves, excluding income taxes, while not a financial measure in accordance with generally accepted accounting principles, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure for our proved reserves as of December 31, 2006 was $470.8 million. The standardized measure gives effect to income taxes, and is calculated in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities. The standardized measure of our estimated net proved reserves of $470.8 million equals the present value of our estimated future net revenue from proved reserves, excluding income taxes, of $534.7 million, less discounted estimated future income taxes relating to such future net revenues of $63.9 million.

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. At year end 2006, we reclassified a portion of Entrada s estimated net proved reserves to probable as of December 31, 2006 due to new performance data from analogous deepwater reservoirs. Please refer to Note 15 of our Consolidated Financial Statements for further information regarding reserves. On December 31, 2006, we owned a 20% working interest in this discovery with BP Exploration and Production Company (BP), the operator, holding the remaining working interest.

Subsequent to December 31, 2006, on March 8, 2007, we entered into an agreement with BP to purchase BP s 80% working interest in the Entrada Field for total cash consideration of $190 million. The purchase price includes $150 million payable at closing and an additional $40 million payable after the achievement of certain production milestones. The purchased interests include five federal offshore blocks at Garden Banks Blocks 738, 782, 785, 826 and 827, subject to certain depth limitations. Upon the completion of the acquisition, we will own a 100% working interest in the Entrada Field and will become operator. The acquisition is expected to close within the next 45 days and will add 150 Bcfe to our proved undeveloped reserves.

The Magnolia field is located on blocks adjacent to Entrada. The field and related production facilities are owned by Conoco/Phillips, the operator, and Devon Energy Corporation. Work has been substantially completed on a front-end engineering design study to tie-back Entrada to the Magnolia production facilities by an integrated project team consisting of a leading engineering firm and personnel from BP and Callon, along with the Magnolia owners. Negotiations between the Magnolia facility owners and Entrada owners for a production handling agreement have been ongoing. We expect to complete these negotiations in the near future once closing of our acquisition of BP s interest in Entrada is complete. Development expenditures are expected to commence in the second half of 2007 with the ordering of long-lead items. The majority of development costs are anticipated to be incurred in 2008 and early 2009. First production is projected to commence in the first quarter of 2009.

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

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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.

During 2006 the field produced 8.2 Bcfe net to us which accounted for 40% of our total production.

Future plans include five recompletions to produce up-hole sands and two sidetracks to undrained areas of the field up-dip or fault separated from existing productions.

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 2,015 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 the last 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 valve 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.

At the time the field was developed, there was no way to know what the drive mechanism would be, so the wells were put at a mid-dip position. It is now known the field drive mechanism is water and the wells need to be at the structural crest for maximum recovery. A sidetrack of the #1 well is planned for this summer to move that well to an up-dip position.

During 2006 Habanero produced 2.1 Bcfe net to us which accounted for 10% of our total production.

Gulf of Mexico Shelf and Onshore Louisiana

High Island Blocks 165/130

The High Island 165 #1 well was spud in the fourth quarter of 2005, reached total depth of 17,029 feet in January 2006 and logged 140 feet of net pay. The well commenced production in October 2006 and during February 2007 was producing at a gross rate of 44 million cubic feet of natural gas per day. We have two development wells in progress, the High Island Block 130 #1 and #2 wells. The #1 well is being

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completed and should commence production at a similar rate late in the first quarter of 2007. In addition to the productive sands discovered by the High Island 165 #1 well, the High Island 130 #1 well encountered two deeper productive sands. The High Island 130 #2 well is drilling and if successful should commence production in the second half of 2007. The High Island 165 #1 well produced 0.4 Bcfe net to our interest in the fourth quarter of 2006. We have a 16.7% working interest in the shallower productive zones and an 11.7% interest in the deeper discovered by the High Island 130 #1 well and the operator of the field is Hydro Gulf of Mexico, LLC.

West Cameron 3/LA

We drilled our Prairie Beach prospect during the first half of 2006 which is located onshore in the state waters of Cameron Parish, Louisiana. The well encountered 37 feet of net pay and began production in October 2006. During 2006, the field produced 0.3 Bcfe net to us. We operate and own a 75% working interest.

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 commenced in late September 2006 and during 2006 the field produced 0.3 Bcfe net to us. The company owns a 60% working interest and Walter Oil and Gas is the operator.

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. The #2 well commenced production in the second quarter of 2006 and encountered mechanical difficulties which were corrected. Sustained production was achieved by the third quarter of 2006. In 2006, we drilled the #4 well, an offset to the #2 well. The #4 well commenced production during December 2006 in a deeper, secondary zone. After this zone is depleted we expect to recomplete the well in the main pay zone. 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. The well was completed in a deeper secondary zone and will probably be recompleted to the main pay zone in early 2008. The well commenced production in August 2006. Callon holds a 20.5% working interest in the block and Cimarex Energy Company is the operator.

During 2006, the West Cameron 295 field produced 0.8 Bcfe net to us.

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. The well is tied back to existing infrastructure on a nearby block. We are the operator and own a 50% working interest. First production commenced in March 2006 and during 2006 the field produced 1.5 Bcfe net to us.

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East Cameron 109
During 2006, an exploratory well was drilled to a vertical depth of 13,110 feet and encountered 54 feet of net pay. The well commenced production during the second half of 2006 and produced 0.1 Bcfe before encountering mechanical problems. Production was restored in January 2007. Callon owns a 25% working interest and Energy Partners, LTD is the operator.

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,		
	2006	**2005**	**2004**
		(In thousands)	
Proved developed:			
Oil (Bbls)	5,159	7,323	10,292
Gas (Mcf)	36,750	30,982	33,982
Mcfe	67,704	74,921	95,735
Proved undeveloped:			
Oil (Bbls)	8,106	11,105	9,456
Gas (Mcf)	29,287	47,039	38,637
Mcfe	77,924	113,667	95,373
Total proved:			
Oil (Bbls)	13,265	18,428	19,748
Gas (Mcf)	66,037	78,021	72,619
Mcfe	145,628	188,588	191,108
Estimated pre-tax future net cash flows (a)	$ 775,742	$ 1,487,817	$ 892,145
Pre-tax discounted present value (a)(b)	$ 534,743	$ 1,088,714	$ 612,595
Standardized measure of discounted future net cash flows(a)(b)	$ 470,791	$ 837,552	$ 515,893

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2006, in accordance with SFAS 143.

(b) We use the financial measure present value of estimated future net revenues from proved reserves, excluding income taxes. This is a non-GAAP financial measure. We believe that present value of estimated future net revenues from proved reserves, excluding income taxes, while not a financial measure in accordance with generally accepted accounting principles, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure for our proved reserves as of December 31, 2006 was $470.8 million. The standardized measure gives effect to income taxes, and is calculated in accordance with Statement of Financial Accounting Standards No. 69, Disclosures About Oil and Gas Producing Activities. The standardized measure of our estimated net proved reserves of $470.8 million equals the present value of our estimated future net revenue from proved reserves, excluding income taxes, of $534.7 million, less discounted estimated future income taxes relating to such future net revenues of $63.9 million.

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Our independent reserve engineers, Huddleston & Co., Inc., prepared the estimates of the proved reserves and the future net cash flows and present value thereof attributable to such proved reserves. Reserves were estimated using oil and gas prices and production and development costs in effect on December 31 of each such year, without escalation, and were otherwise prepared in accordance with 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,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil			1	0.15		
Gas	2	0.37			2	1.22
Non-productive						
Total	2	0.37	1	0.15	2	1.22
Exploration:						
Oil						
Gas	5	2.05	7	2.42	2	0.72
Non-productive	8	2.98	4	1.25	5	1.24
Total	13	5.03	11	3.67	7	1.96

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The following table sets forth our productive wells as of December 31, 2006:

	Wells	
	Gross	Net
Oil:		
Working interest	40.00	3.90
Royalty interest	193.00	3.15
Total	233.00	7.05
Gas:		
Working interest	35.00	14.40
Royalty interest	211.00	1.49
Total	246.00	15.89

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, 2006, we had no wells with multiple completions. At December 31, 2006, 1 gross (0.033 net) exploration oil well, 1 gross (0.255 net) exploration gas well and 1 gross (0.117 net) development 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, 2006.

	Leasehold Acreage			
	Developed		Undeveloped	
Location	**Gross**	**Net**	**Gross**	**Net**
Louisiana	6,274	4,019	10,706	4,454
Texas	78		15,150	7,616
Other states			681	509
Federal waters	107,029	53,930	357,270	152,105
Total	113,381	57,949	383,807	164,684

As of December 31, 2006, we owned various royalty and overriding royalty interests in 553 net developed and 7,645 net undeveloped acres. In addition, we owned 4,071 developed and 121,929 undeveloped mineral acres.

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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:

	December 31		
	2006	2005	2004
Shell Trading Company	41%	34%	30%
Louis Dreyfus Energy Services	25%	16%	23%
Plains Marketing, L.P.	11%	16%	13%
Chevron Texaco Natural Gas	3%	10%	6%

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.

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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 2006.

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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
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
2006:		
First quarter	$21.25	$17.01
Second quarter	21.99	15.12
Third quarter	19.96	12.54
Fourth quarter	17.44	12.48

As of March 5, 2007 there were approximately 4,057 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.

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Performance Graph

The following graph compares the yearly percentage change for the five years ended December 31, 2006, in the cumulative total shareholder return on the Company s Common Stock against the cumulative total return for the (i) Hemscott Industry and Market Index of SIC Group 123 (the Hemscott Group Index) consisting of independent oil and gas drilling and exploration companies and (ii) the New York Stock Exchange Market Index. The comparison of total return on an investment for each of the periods assumes that $100 was invested on December 31, 2001 in the Company, the Hemscott Group Index and the New York Stock Exchange Market Index, and that all dividends were reinvested.

COMPARE 5-YEAR CUMULATIVE TOTAL RETURN
AMONG CALLON PETROLEUM COMPANY
NYSE MARKET INDEX AND HEMSCOTT GROUP INDEX
ASSUMES $100 INVESTED ON DEC. 31, 2001
ASSUMES DIVIDEND REINVESTED
FISCAL YEAR ENDING DEC. 31, 2006

	2001	**2002**	**2003**	**2004**	**2005**	**2006**
Callon Petroleum Company	$100	$49	$151	$211	$258	$219
Hemscott Group Index	$100	$93	$121	$170	$268	$318
NYSE Market Index	$100	$82	$106	$119	$129	$152

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, 2006 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.

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

	Years Ended December 31,				
	2006	**2005**	**2004**	**2003**	**2002**
Statement of Operations Data:					
Operating revenues:					
Oil and gas sales	$ 182,268	$ 141,290	$ 119,802	$ 73,697	$ 61,171
Operating expenses:					
Lease operating expenses	28,881	24,377	22,308	11,301	11,030
Depreciation, depletion and amortization	65,283	44,946	47,453	28,253	27,096
General and administrative	8,591	8,085	8,758	4,713	4,705
Accretion expense	4,960	3,549	3,400	2,884	
Derivative expense	150	6,028	1,371	535	708
Total operating expenses	107,865	86,985	83,290	47,686	43,539
Income from operations	74,403	54,305	36,512	26,011	17,632
Other (income) expenses:					
Interest expense	16,480	16,660	20,137	30,614	26,140
Other (income)	(1,869)	(998)	(357)	(444)	(1,004)
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)
Total other (income) expenses	14,611	15,662	22,784	35,743	20,203
Income (loss) before income taxes	59,792	38,643	13,728	(9,732)	(2,571)
Income tax expense (benefit)	20,707	13,209	(6,697)	8,432	(900)
Income (loss) before equity in earnings of Medusa Spar LLC and cumulative effect of change in accounting principle	39,085	25,434	20,425	(18,164)	(1,671)
Equity in earnings of Medusa Spar LLC, net of tax	1,475	1,342	1,076	(8)	
Income (loss) before cumulative effect of change in in accounting principle	40,560	26,776	21,501	(18,172)	(1,671)
Cumulative effect of change in accounting principle, net of tax				181	
Net income (loss)	40,560	26,776	21,501	(17,991)	(1,671)

Preferred stock dividends		318	1,272	1,277	1,277
Net income (loss) available to common shares	$ 40,560	$ 26,458	$ 20,229	$ (19,268)	$ (2,948)

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

	Years Ended December 31, 2006	2005	2004	2003	2002
Net income (loss) per common share:					
Basic:					
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 2.00	$ 1.43	$ 1.28	$ (1.42)	$ (.22)
Cumulative effect of change in accounting principle, net of tax				.01	
Net income (loss) available to common	$ 2.00	$ 1.43	$ 1.28	$ (1.41)	$ (.22)
Diluted:					
Net income (loss) available to common before cumulative effect of change in accounting principle	$ 1.90	$ 1.28	$ 1.22	$ (1.42)	$ (.22)
Cumulative effect of change in accounting principle, net of tax				.01	
Net income (loss) available to common	$ 1.90	$ 1.28	$ 1.22	$ (1.41)	$ (.22)
Shares used in computing net income (loss) per common share:					
Basic	20,270	18,453	15,796	13,662	13,387
Diluted	21,363	20,883	17,678	13,662	13,387
Balance Sheet Data (end of period):					
Oil and gas properties, net	$ 547,027	$ 447,364	$ 406,690	$ 390,163	$ 377,661
Total assets	$ 625,527	$ 533,776	$ 457,523	$ 496,032	$ 410,613
Long-term debt, less current portion	$ 225,521	$ 188,813	$ 192,351	$ 214,885	$ 248,269
Stockholders equity	$ 281,363	$ 228,048	$ 198,312	$ 133,261	$ 140,960

We follow the full-cost method of accounting for oil and gas properties. Under this method of accounting, our net capitalized costs to acquire, explore and develop oil and gas properties may not 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, net of tax (the full-cost ceiling amount). If these capitalized costs exceed the full-cost ceiling amount, the excess is charged to expense.

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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 relating to our financial and operating results for the year ended December 31, 2006 included the closing of our four-year amended and restated senior secured credit facility which was underwritten by Union Bank of California, N.A. The credit facility has an initial borrowing base of $75 million, which will be reviewed and redetermined semi-annually and can be increased to a maximum of $175 million. We expect planned 2007 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 $40 million available at December 31, 2006. For a more detailed discussion of outstanding debt see Note 7 to our Consolidated Financial Statements.

Our estimated net proved oil and gas reserves decreased at December 31, 2006 to 145.6 Bcfe. This represents a decrease of 23% from previous year-end 2005 estimated proved reserves of 188.6 Bcfe.

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 the proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. We use derivative financial instruments (see Note 8 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 these instruments for trading purposes. On a Mcfe basis, natural gas represents approximately 73% of budgeted 2007 production and 45% of proved reserves at year-end 2006.

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

Summary of Significant Accounting Policies

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 that could change. These estimates are described below.

Depreciation, Depletion and Amortization (DD&A) of Oil and Gas Properties. We calculate depletion by using the net capitalized costs in our full-cost pool plus future development costs (combined, the depletable base) and our estimated net proved reserve quantities. Capitalized costs added to the full-cost pool 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 classified as unevaluated property costs and are excluded from the depletable base. These unevaluated property costs are added to the depletable base 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;

- estimated costs to dismantle, abandon and restore properties that are capitalized to the full-cost pool when the related liabilities are incurred under SFAS 143; and

- 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.

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 the proved reserves quantities at the beginning of each accounting period. For each barrel of Mcfe 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 rates may change if the estimates and assumptions are not realized. Such changes may be material.

Ceiling Test. Under the full-cost accounting rules of the SEC, we review the carrying value of our proved oil and gas properties each quarter. Under these rules, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization 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%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full-cost ceiling amount). 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. However, if prices recover sufficiently subsequent to the balance sheet date before the release of the financial statements then use of the subsequent pricing is allowed and no write-down would be required if same pricing was used. Given the volatility of oil and gas prices, it is reasonably possible that our 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 write-downs 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 estimated future net cash flows from 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 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 estimated future net cash flows from 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 of estimated future net cash flows more than the estimated 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 estimated oil and gas quantities and the present value of estimated future net cash flows, while decreases in costs will increase such amounts. Because our properties have relatively short productive lives, changes in costs will affect the present value of estimated future net cash flows more than the estimated quantities of oil and gas reserves; and

- the potential royalties payable to the Mineral Management Service. See Note 9 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 depletable base. These unproved properties are included in the line item Unevaluated properties excluded from amortization. Unproved property costs are transferred to the depletable base 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, include the costs of such properties in the depletable base. 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. We account for asset retirement obligations in accordance with Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143), which 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. Interest is accreted on the present value of the asset retirement obligation and reported as accretion expense within operating expenses in the Consolidated Statements of Operations. See Note 10 to our Consolidated Financial Statements.

Derivatives. We periodically use derivative financial instruments to manage oil and gas price risk on a limited amount of our future production and do not use these instruments for trading purposes. Settlement of derivative contracts are generally based on the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price. Such derivatives are

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

Our 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 our derivative contracts that are not designated as effective cash flow hedges are recorded through the statement of operations as derivative expense (income). See Note 8 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 Accounting for Income Taxes (SFAS 109). SFAS 109 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.

Share-Based Compensation. Effective January 1, 2006, we adopted Statement of Financial Accounting Standard No. 123 (revised 2004), Share-Based Payment, (SFAS 123R) utilizing the modified prospective transition method. Prior to the adoption of SFAS 123R, we accounted for stock option grants in accordance with Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (the intrinsic value method) and, accordingly, recognized no compensation expense for stock option grants.

Under the modified prospective transition method, SFAS 123R applies to new awards, unvested awards as of January 1, 2006 and awards that were outstanding on January 1, 2006 that are subsequently modified, repurchased or cancelled. Under the modified prospective transition method, compensation cost recognized in 2006 includes compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of Statement of Financial Accounting Standard No. 123 Accounting for Stock-Based Compensation, (SFAS 123) and compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

SFAS 123R requires the cash flows from tax benefits resulting from tax deductions in excess of compensation cost recognized for stock options exercised (excess tax benefits) to be classified as financing cash flows. The $1.4 million of excess tax benefits classified as a financing cash inflow for the year ended December 31, 2006 would have been classified as an operating cash flow had we not adopted SFAS 123R. There were no cash proceeds from the exercise of stock options for the year ended December 31, 2006 due to the fact that all options were exercised through net-share settlements. As a result of most of our stock-based compensation being in the form of restricted stock, the impact of the adoption of SFAS 123R on income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006 was immaterial. See Note 3 to our Consolidated Financial Statements.

New Accounting Standards

In June 2006, the Financial Accounting Standards Board (FASB) released interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48). FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position must meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest

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and penalties, accounting in interim periods, disclosure and transition. The effective date for FIN 48 is fiscal years beginning after December 15, 2006. We are currently reviewing the provisions of FIN 48 and have not yet determined the impact of adoption.

In September 2006, the FASB issued Statement of Financial Accounting Standard No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. We are still reviewing the provisions of SFAS 157 and have not yet determined the impact of adoption.

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 by $669,000 during 2006 to $1.9 million. Cash provided from operating activities during 2006 totaled $135.5 million, an increase of 83% from $74.0 million in 2005.

On August 30, 2006, we closed on a four-year amended and restated senior secured credit facility underwritten by Union Bank of California, N.A. The credit facility includes an initial borrowing base of $75 million, which will be reviewed and redetermined semi-annually and can be increased to a maximum of $175 million. During 2006 we drew $35 million under our facility which was outstanding as of December 31, 2006 and $40 million was available for future borrowings. In connection with the anticipated financing of the acquisition of BP s interest in the Entrada Field, the borrowing base under this facility would be reduced to $50 million at closing until the next borrowing base redetermination date. Please refer to Subsequent Events below for more discussion on the Entrada acquisition.

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 7 to the Consolidated Financial Statements for a more detail discussion of long-term debt.

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, 2006.

Our oil and gas reserves as estimated by Huddleston & Co., Inc. were 145.6 Bcfe of natural gas equivalents on December 31, 2006. Our cash flow from operations during 2006 was generated by the production of 20.8 Bcfe. Production of our reserves during 2007, without weather-related downtime, is projected to be higher than 2006 due to new discoveries that are projected to commence initial production during the year, which is expected to offset anticipated declines from our current producing properties.

In addition to the acquisition of BP s interest in the Entrada field, our planned capital expenditures for 2007 total $125 million and include capitalized interest and general and administrative expenses. The current portion of our asset retirement obligation will require an additional $10 million resulting in total capital expenditures of $135 million for 2007. Capital expenditure plans for 2007 include:

- the discretionary drilling of up to 17 exploratory and development wells;
- lease and seismic acquisition; and
- capitalized interest and overhead.

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We believe that our operating cash flow and our credit facility will be adequate to meet our capital, debt repayment, and operating requirements for 2007. 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 and repayment of maturing debt.

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 may 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.

The following table describes our outstanding contractual obligations as of December 31, 2006 (in thousands):

		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	$ 35,000	$	$	$ 35,000	$
9.75% Senior Notes	200,000			200,000	
Capital lease (future minimum payments)	1,270	348	457	446	19
Throughput Commitments:					
Medusa Spar LLC	8,848	3,152	5,696		
Medusa Oil Pipeline	400	105	132	101	62
	$ 245,518	$ 3,605	$ 6,285	$ 235,547	$ 81

Subsequent Events

Subsequent to December 31, 2006, on March 8, 2007, we entered into an agreement with BP to purchase BP s 80% working interest in the Entrada Field for total cash consideration of $190 million. The purchase price includes $150 million payable at closing and an additional $40 million payable after the achievement of certain production milestones. The purchased interests include five federal offshore blocks at Garden Banks Blocks 738, 782, 785, 826 and 827, subject to certain depth limitations. Upon the completion of the acquisition, we will own a 100% working interest in the Entrada Field and will become operator. The acquisition is expected to close within the next 45 days and will add 150 Bcfe to our proved undeveloped reserves.

To finance the initial $150 million payment of the purchase price, a commitment has been received from Merrill Lynch Capital Corporation to make available to us a 7-year, $200 million revolving credit facility secured by a lien on the Entrada properties. We plan to borrow the full commitment amount at closing to cover the required $150 million payment to BP and, expenses and fees, and the balance of the funds can be used for Entrada development cost or general corporate purposes.

Off-Balance Sheet Arrangements

We have a 10% ownership interest in Medusa Spar LLC (LLC), which is a limited liability company that owns a 75% undivided ownership interest in the deepwater spar production facilities on our Medusa

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Field in the Gulf of Mexico. We contributed a 15% undivided ownership interest in the production facility to the LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC earns 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, 2006, $33.2 million of the financing was outstanding. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy. We are accounting for its 10% ownership interest in the LLC under the equity method.

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, 2006.

	December 31,		
	2006	**2005**	**2004**
Production:			
Oil (MBbls)	1,634	1,837	1,736
Gas (MMcf)	10,977	7,768	11,387
Total production (MMcfe)	20,780	18,787	21,801
Average daily production (MMcfe)	56.9	51.5	59.6
Average sales price:			
Oil (per Bbl) (a)	$ 57.33	$ 41.61	$ 28.71
Gas (per Mcf)	$ 8.07	$ 8.35	$ 6.15
Total (per Mcfe)	$ 8.77	$ 7.52	$ 5.50
Oil and gas revenues (in thousands):			
Oil revenue	$ 93,665	$ 76,425	$ 49,826
Gas revenue	88,603	64,865	69,976
Total	$ 182,268	$ 141,290	$ 119,802
Lease operating expenses (in thousands)	$ 28,881	$ 24,377	$ 22,308
Additional per Mcfe data:			
Sales price	$ 8.77	$ 7.52	$ 5.50
Lease operating expenses	1.39	1.30	1.02
Operating margin	$ 7.38	$ 6.22	$ 4.48
Depletion	$ 3.14	$ 2.39	$ 2.18
General and administrative (net of management fees)	$ .41	$ .43	$ .40

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

Average NYMEX oil price	$ 66.22	$ 56.57	$ 41.38
Basis differential and quality adjustments	(7.03)	(8.45)	(4.60)
Transportation	(1.25)	(1.26)	(1.27)
Hedging	(0.61)	(5.25)	(6.80)
Average realized oil price	$ 57.33	$ 41.61	$ 28.71

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Comparison of Results of Operations for the Years Ended December 31, 2006 and 2005

Oil and Gas Revenues

Total oil and gas revenues increased 29% from $141.3 million in 2005 to $182.3 million in 2006 primarily due to higher gas production and oil pricing. Total production for 2006 increased by 11% versus 2005, which was impacted by downtime for inclement weather.

Gas production during 2006 totaled 11.0 Bcf and generated $88.6 million in revenues compared to 7.8 Bcf and $64.9 million in revenues during the same period in 2005. Average gas prices realized for 2006 were $8.07 per Mcf compared to $8.35 per Mcf during the same period in 2005. The increase in production was primarily due to production from our new wells at East Cameron Block 90, North Padre Island Block 913, High Island Block 73, Brazos Block 405, West Cameron Block 295, High Island 165 and West Cameron 3/LA and 2005 production being negatively impacted by inclement weather. The increase in production from new properties was partially offset by normal and expected declines in production from our Habanero, High Island Block 119 and Mobile Bay area fields and older properties.

Oil production during 2006 totaled 1,634,000 barrels and generated $93.7 million in revenues compared to 1,837,000 barrels and $76.4 million in revenues for the same period in 2005. Average oil prices realized in 2006 were $57.33 per barrel compared to $41.61 per barrel in 2005. Oil production decreased during 2006 primarily due to a normal and expected decline at Habanero. See the Results of Operations table for a reconciliation of the realized oil prices to average NYMEX.

Lease Operating Expenses

Lease operating expenses for 2006 increased by 18% to $28.9 million compared to $24.4 million for the same period in 2005. The increase was primarily due to new wells coming on line, higher costs for fuel and marine transportation and an increase in insurance rates for our policies which were renewed on April 1, 2006. In addition, we incurred approximately $1.5 million for pipeline repairs at our South Marsh Island Block 261 field and had downhole repairs at our Medusa field.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2006 and 2005 was $65.3 million and $44.9 million, respectively. The 45% increase was due to higher production volumes and a higher average depletion rate for 2006 compared to 2005. The higher rate is primarily attributable to an increase in finding costs, estimated costs of future development and capitalized asset retirement costs.

Accretion Expense

Accretion expense for 2006 and 2005 of $5.0 million and $3.5 million, respectively, represents accretion of our asset retirement obligations. The increase was due to the addition of plugging and abandonment obligations associated with new discoveries and an increase in plugging and abandonment cost estimates. See Note 10 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses for 2006, net of amounts capitalized, were $8.6 million compared to $8.1 million in 2005. The $500,000 (6%) increase in general and administrative expenses was due to increased overall cost. We recognized non-cash charges of approximately $1.1 million in the third quarter of 2006 for the vesting of 20% of restricted shares granted in August 2006. General and administrative expenses for 2005 included non-cash charges of $930,000 recognized in the second quarter of 2005 for the accelerated vesting of performance shares pursuant to the terms of the plan due to deaths or disability for an executive officer and two directors of the Company. See Note 3 for more details.

Interest Expense

Interest expense was relatively consistent in 2006 in the amount of $16.5 million compared to $16.7 million in 2005.

Income Taxes

For 2006, we had income tax expense of $20.7 million compared to $13.2 million in 2005. The 57% increase was due to an increase in income before income taxes.

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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 increased pricing. Total production for 2005 decreased by 14% as compared to 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.

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 the Results of Operations table for a reconciliation of the realized oil prices to average NYMEX.

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 cost of repairs to our properties for damages caused by tropical storms and hurricanes in the net amount of $1.2 million. This amount includes 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 of our asset retirement obligations. See Note 10 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses for 2005, net of amounts capitalized, were $8.1 million compared to $8.8 million in 2004. Expenses for 2004 included a $2.6 million charge that was incurred in the first quarter of 2004 for the early retirement of two executive officers of the Company. Expenses for 2005 included a $930,000 non-cash charge for the accelerated vesting of performance shares pursuant to the terms of the plan due to death or disability for an executive officer and two directors of the Company. Expenses for 2005 also increased due to a reduction in the amount of overhead which was capitalized.

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 on early extinguishment of debt of $3.0 million was recognized in 2004 for the write-off of deferred financing costs and bond discounts as well as pre-payment premiums 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 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 as of December 31, 2004. See Note 5 to our Consolidated Financial Statements for a more detailed discussion.

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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. The prices for oil and gas remain extremely volatile and sometimes experience large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, the Company enters into derivative financial instruments to manage oil and gas price risk.

The Company may utilize fixed price swaps , which reduce the Company s exposure to decreases in commodity prices and limit the benefit the Company might otherwise have received from any increases in commodity prices.

The Company may utilize price collars to reduce the risk of changes in oil and gas prices. Under these arrangements, no payments are due by either party as long as the market price is above the floor price and below the ceiling price set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to the Company, and if the price rises above the ceiling, the counter-party receives the difference from the Company.

Callon may purchase puts which reduce the Company s exposure to decreases in oil and gas prices while allowing realization of the full benefit from any increases in oil and gas prices. If the price falls below the floor, the counter-party pays the difference to the Company.

The Company enters into these various agreements from time to time to reduce the effects of volatile oil and gas prices and does not enter into derivative transactions for speculative purposes. However, certain of the Company s derivative positions may not be designated as hedges for accounting purposes. See Note 8 to the Consolidated Financial Statements for a description of the Company s hedged position at December 31, 2006. 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 2007 (excluding incremental production from 2007 exploratory drilling), a 10% decline in the prices Callon receives for its crude oil and natural gas production would have an approximate $12 million impact on our revenues.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the financial statements, in 2006 the Company changed its method of accounting for stock-based compensation.

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, 2006, 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 15, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New Orleans, Louisiana
March 15, 2007

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

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,896	$ 2,565
Accounts receivable	32,166	33,195
Deferred tax asset		26,770
Restricted investments	4,306	4,110
Fair market value of derivatives	13,311	889
Other current assets	5,973	1,998
Total current assets	57,652	69,527
Oil and gas properties, full-cost accounting method:		
Evaluated properties	1,096,907	937,698
Less accumulated depreciation, depletion and amortization	(604,682)	(539,399)
	492,225	398,299
Unevaluated properties excluded from amortization	54,802	49,065
Total oil and gas properties	547,027	447,364
Other property and equipment, net	1,996	1,605
Long-term gas balancing receivable	714	403
Restricted investments	1,935	1,858
Investment in Medusa Spar LLC	12,580	11,389
Other assets, net	3,623	1,630
Total assets	$ 625,527	$ 533,776
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 43,086	$ 39,323
Fair market value of derivatives		1,247
Undistributed oil and gas revenues	3,525	721
Asset retirement obligations	14,355	21,660
Current maturities of long-term debt	213	263
Total current liabilities	61,179	63,214

Long-term debt	225,521	188,813
Asset retirement obligations	26,824	16,613
Deferred tax liability	30,054	31,633
Accrued liabilities to be refinanced		5,000
Other long-term liabilities	586	455
Total liabilities	344,164	305,728
Stockholders equity:		
Preferred Stock, $.01 par value; 2,500,000 shares authorized;		
Common Stock, $.01 par value; 30,000,000 shares authorized; 20,747,773 shares and 19,357,138 shares issued and outstanding at December 31, 2006 and 2005, respectively	207	194
Unearned compensation-restricted stock		(3,334)
Capital in excess of par value	220,785	220,360
Other comprehensive income (loss)	8,652	(331)
Retained earnings	51,719	11,159
Total stockholders equity	281,363	228,048
Total liabilities and stockholders equity	$ 625,527	$ 533,776

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

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Callon Petroleum Company
Consolidated Statements of Operations
For the Years Ended December 31, 2006, 2005 and 2004
(In thousands, except per share amounts)

	2006	2005	2004
Operating revenues:			
Oil sales	$ 93,665	$ 76,425	$ 49,826
Gas sales	88,603	64,865	69,976
Total operating revenues	182,268	141,290	119,802
Operating expenses:			
Lease operating expenses	28,881	24,377	22,308
Depreciation, depletion and amortization	65,283	44,946	47,453
General and administrative	8,591	8,085	8,758
Accretion expense	4,960	3,549	3,400
Derivative expense	150	6,028	1,371
Total operating expenses	107,865	86,985	83,290
Income from operations	74,403	54,305	36,512
Other (income) expenses:			
Interest expense	16,480	16,660	20,137
Other (income)	(1,869)	(998)	(357)
Loss on early extinguishment of debt			3,004
Total other (income) expenses	14,611	15,662	22,784
Income before income taxes	59,792	38,643	13,728
Income tax expense (benefit)	20,707	13,209	(6,697)
Income before equity in earnings of Medusa Spar LLC	39,085	25,434	20,425
Equity in earnings of Medusa Spar LLC, net of tax	1,475	1,342	1,076
Net income	40,560	26,776	21,501
Preferred stock dividends		318	1,272
Net income available to common shares	$ 40,560	$ 26,458	$ 20,229
Net income per common share:			

Basic	$ 2.00	$ 1.43	$ 1.28
Diluted	$ 1.90	$ 1.28	$ 1.22
Shares used in computing net income per share amounts:			
Basic	20,270	18,453	15,796
Diluted	21,363	20,883	17,678

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

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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, 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:							
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
Comprehensive income:							
Net income						40,560	
Other comprehensive income					8,983		
Total comprehensive income							49,543
Shares issued pursuant to employee benefit and option plan		2		(441)			(439)
Tax benefits related to stock compensation plans				1,356			1,356
Adoption of 123R			3,334	(3,334)			
Restricted stock		1		2,854			2,855
Warrants		10		(10)			
Balances, December 31, 2006	$	$ 207	$	$ 220,785	$ 8,652	$ 51,719	$ 281,363

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2006, 2005 and 2004
(In thousands)

	2006	2005	2004
Cash flows from operating activities:			
Net income	$ 40,560	$ 26,776	$ 21,501
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	65,929	45,657	48,164
Accretion expense	4,960	3,549	3,400
Amortization of deferred financing costs	2,221	2,062	1,929
Non-cash loss on extinguishment of debt			2,910
Equity in earnings of Medusa Spar, LLC	(1,475)	(1,342)	(1,076)
Non-cash derivative expense	150	1,635	(135)
Deferred income tax expense (benefit)	20,707	13,209	(6,697)
Non-cash charge related to compensation plans	1,420	1,906	1,225
Excess tax benefits from share-based payment arrangements	(1,449)		
Changes in current assets and liabilities:			
Accounts receivable, trade	(2,107)	(11,169)	(4,495)
Other current assets	(3,975)	670	971
Current liabilities	11,311	(8,666)	2,903
Change in gas balancing receivable	(311)	322	376
Change in gas balancing payable	133	(289)	400
Change in other long-term liabilities	(2)	(18)	(20)
Change in other assets, net	(2,588)	(292)	(448)
Cash provided by operating activities	135,484	74,010	70,908
Cash flows from investing activities:			
Capital expenditures	(167,979)	(73,072)	(64,649)
Distribution from Medusa Spar, LLC	1,078	463	339
Cash used by investing activities	(166,901)	(72,609)	(64,310)
Cash flows from financing activities:			
Change in accrued liabilities to be refinanced	(5,000)	5,000	
Increases in debt	88,000	7,000	90,000
Payments on debt	(53,000)	(12,000)	(205,915)
Restricted cash			63,345
Debt issuance cost			(984)
Issuance of common stock		2	44,047
Buyout of preferred stock		(637)	
Equity issued related to employee stock plans	(438)	(573)	199
Excess tax benefits from share-based payment arrangements	1,449		
Capital leases	(263)	(576)	(1,452)

Cash dividends on preferred stock		(318)	(1,272)
Cash provided (used) by financing activities	30,748	(2,102)	(12,032)
Net decrease in cash and cash equivalents	(669)	(701)	(5,434)
Cash and cash equivalents:			
Balance, beginning of period	2,565	3,266	8,700
Balance, end of period	$ 1,896	$ 2,565	$ 3,266

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

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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 9.

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 U.S. 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

The Company accounts for asset retirement obligations in accordance with Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143), which 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. Interest is accreted on the present value of the asset retirement obligation and reported as accretion expense within operating expenses in the Consolidated Statements of Operations. See Note 10.

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 ($9.6 million in 2006, $7.1 million in 2005 and $7.2 million in 2004) 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 oil and gas 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, net of tax effects (the full-cost ceiling amount), then such excess is charged to expense during the period in which the excess occurs. See Note 11.

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. In accordance with SFAS 143, such costs are capitalized to the full-cost pool when the related liabilities are incurred. In accordance with Staff Accounting Bulletin 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 $351,000, $355,000 and $346,000 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, 2006, 2005 and 2004, respectively. The accumulated depreciation on other property and equipment was $10.8 million and $10.6 million as of December 31, 2006 and 2005, respectively.

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Investment in Medusa Spar LLC

The Company has a 10% ownership interest in Medusa Spar, LLC (LLC), which is a limited liability company that 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 the LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC earns a tariff based upon production volume throughput from the Medusa area. Callon is obligated to process its 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, 2006, $33.2 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 its 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 recording a liability to the extent that a well is in an overtake position. Gas balancing receivables were $714,000 and $403,000 as of December 31, 2006 and 2005, respectively. Gas balancing payables were $437,000 and $304,000 as of December 31, 2006 and 2005, respectively.

Derivatives

The Company periodically uses derivative financial instruments to manage oil and gas price risk on a limited amount of its future production and does not use these instruments for trading purposes. Settlement of derivative contracts are generally based on the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price. Such derivatives are accounted for under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) as amended.

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). See Note 8.

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). SFAS 109 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 5.

Stock-Based Compensation

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standard No. 123 (revised 2004), Share-Based Payment, (SFAS 123R) utilizing the modified prospective transition method. Prior to the adoption of SFAS 123R, the Company accounted for stock option grants in accordance with Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees (the intrinsic value method) and, accordingly, recognized no compensation expense for stock option grants.

Under the modified prospective transition method, SFAS 123R applies to new awards, unvested awards as of January 1, 2006 and awards that were outstanding on January 1, 2006 that are subsequently modified, repurchased or cancelled. Under the modified prospective transition method, compensation cost recognized in 2006 includes compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of Statement of Financial Accounting Standard No. 123 Accounting for Stock-Based Compensation, (SFAS 123) and compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

SFAS 123R requires the cash flows from tax benefits resulting from tax deductions in excess of compensation cost recognized for stock options exercised (excess tax benefits) to be classified as financing cash flows. The $1.4 million of excess tax benefits classified as a financing cash inflow for the year ended December 31, 2006 would have been classified as an operating cash flow had the Company not adopted SFAS 123R. There were no cash proceeds from the exercise of stock options for the year ended December 31, 2006 due to the fact that all options were exercised through net-share settlements. As a result of most of the Company s stock-based compensation being in the form of restricted stock, the impact of the adoption of SFAS 123R on income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006 was not significant. 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 at both December 31, 2006 and 2005, respectively. There were no net charge offs recorded against the reserve for doubtful accounts and no provisions to expense in the three-year period ended December 31, 2006.

Accrued Liabilities to be Refinanced

Amounts included in accrued liabilities to be refinanced at December 31, 2005 represent capital expenditures that were refinanced with the availability under the Company s senior secured credit facility subsequent to December 31, 2005.

Major Customers

The Company s production is generally sold 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,		
	2006	**2005**	**2004**
Shell Trading Company	41%	34%	30%
Louis Dreyfus Energy Services	25%	16%	23%
Plains Marketing, L.P.	11%	16%	13%
Chevron Texaco Natural Gas	3%	10%	6%

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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 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, 2006. During the years ended December 31, 2006, 2005 and 2004, the Company made cash payments for interest of $20,468,000, $19,854,000 and $23,197,000, respectively.

Fair Value of Financial Instruments

Fair value of cash and cash equivalents, accounts receivable, accounts payable, the capital lease and the senior secured credit facility approximates book value at December 31, 2006 and 2005. The Company s 9.75% Senior Notes due 2010 had an estimated fair value of 101.5% and 103% of face value at December 31, 2006 and 2005, respectively.

Accounting Pronouncements

In June 2006, the Financial Accounting Standards Board (FASB) released interpretation No. 48, Accounting for Uncertainty in Income Taxes, (FIN 48). FIN 48 clarifies the accounting for income taxes by prescribing the minimum recognition threshold a tax position must meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. The effective date for FIN 48 is fiscal years beginning after December 15, 2006. The Company is currently reviewing the provisions of FIN 48 and has not yet determined the impact of adoption.

In September 2006, the FASB issued Statement of Financial Accounting Standard No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. SFAS 157 is effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The Company is still reviewing the provisions of SFAS 157 and has not yet determined the impact of adoption.

3. STOCK-BASED COMPENSATION

The Company has various stock plans (Plans) under which employees of the Company and its subsidiaries and non-employee members of the Board of Directors of the Company have been or may be granted certain stock-based compensation. For further discussion of the Plans, refer to Note 12.

For the year ended December 31, 2006, the Company recorded stock-based compensation expense of $3.5 million, of which $1.8 million was included in general and administrative expenses and $1.7 million was capitalized to

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oil and gas properties. Shares available for future stock option or restricted stock grants to employees and directors under existing plans were 490,666 at December 31, 2006.

The following table illustrates the effect on operating results and net income per share had the Company accounted for stock-based compensation in accordance with SFAS 123 for the years ended December 31, 2005 and 2004:

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

Stock Options

The Company uses the Black-Scholes option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods.

	For the Years Ended December 31,		
	2006	2005	2004
Dividend yield			
Expected volatility	38.9%	37.5%	45.1%
Risk-free interest rate	4.6%	4.3%	3.7%
Expected life of option (in years)	5	5	5
Weighted-average grant-date fair value	$7.72	$5.93	$5.48
Forfeiture rate	7.5%		

The assumptions above are based on multiple factors, including historical exercise patterns of employees with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns and the historical volatility of the Company s stock price.

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The following table represents stock option activity and weighted average exercised prices for the three years ended December 31, 2006:

	2006		2005		2004	
	Shares	Wtd Avg Ex Price	Shares	Wtd Avg Ex Price	Shares	Wtd Avg Ex Price
Outstanding, beginning of year	1,205,558	$ 10.11	1,512,599	$ 9.93	2,450,867	$ 9.84
Granted (at market)	15,000	18.69	65,000	15.79	25,000	12.40
Exercised	(480,333)	10.66	(329,441)	10.34	(437,918)	9.74
Forfeited					(525,350)	9.80
Expired			(42,600)	10.60		
Outstanding, end of year	740,225	$ 9.93	1,205,558	$ 10.11	1,512,599	$ 9.93
Exercisable, end of year	695,225	$ 9.44	1,166,558	$ 9.88	1,446,486	$ 10.20

	2006	2005	2004
Weighted-average remaining Contract life:			
Outstanding options at end of period	4.06 yrs.	3.98 yrs.	4.48 yrs.
Outstanding exercisable at end of period	3.76 yrs.	3.79 yrs.	4.34 yrs.

The aggregate intrinsic value of options outstanding was $3.9 million and the aggregate intrinsic value of options exercisable was $3.9 million. Total intrinsic value of options exercised was $4.1 million for the year ended December 31, 2006. At December 31, 2006, there was $231,000 of unrecognized compensation cost related to nonvested stock options, which is expected to be recognized over a weighted-average period of two years.

Restricted Stock

The Plans allow for the issuance of restricted stock awards. The unearned stock-based compensation related to these awards is being amortized to compensation expense on a straight-line basis over the requisite service period for the entire award. The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest. As of December 31, 2006, there was $9.1 million of unrecognized compensation cost associated with these awards, which is expected to be recognized over a weighted average period of 3.3 years.

The following table represents unvested restricted stock activity for the year ended December 31, 2006:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Outstanding shares at beginning of period	272,000	$ 13.66
Granted	582,500	15.77
Vested	(191,500)	15.02
Forfeited	(4,200)	13.82
Outstanding shares at end of period	658,800	$ 15.13

For the years ended December 31, 2006, 2005 and 2004 the Company recognized non-cash compensation expense associated with the restricted stock awards of $3.4 million, $2.0 million and $906,000, respectively. Included in 2005 was $1.0 million of accelerated vesting of performance shares pursuant to the terms of the plan due to the deaths or disability for an executive officer and two directors of the Company. There were no restricted stock grants during the year ended December 31, 2005 and the weighted average grant-date fair value of restricted stock granted during the year ended December 31, 2004 was $13.69.

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4. NET INCOME PER SHARE

Basic net income per common share was computed by dividing net income by the weighted average number of shares of common stock outstanding during the year. Diluted net income 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).

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

	2006	2005	2004
(a) Net income available to common shares	$ 40,560	$ 26,458	$ 20,229
Preferred dividends assuming conversion of preferred stock (if dilutive)		318	1,272
(b) Net income available to common shares assum- ing conversion of preferred stock (if dilutive)	$ 40,560	$ 26,776	$ 21,501
(c) Weighted average shares outstanding	20,270	18,453	15,796
Dilutive impact of stock options	238	348	233
Dilutive impact of restricted stock	78	69	75
Dilutive impact of warrants	777	1,375	894
Convertible preferred stock (if dilutive)		638	680
(d) Weighted average shares outstanding for diluted net income per share	21,363	20,883	17,678
Stock options and warrants excluded due to the exercise price being greater than the stock price	28	1	89
Basic net income per share (a¸c)	$ 2.00	$ 1.43	$ 1.28
Diluted net income per share (b¸d)	$ 1.90	$ 1.28	$ 1.22

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5. INCOME TAXES

Below is an analysis of the net deferred tax liability as of December 31, 2006 and 2005.

	December 31, 2006	December 31, 2005
	(In thousands)	
Deferred Tax Asset:		
Federal net operating loss carryforwards	$ 58,051	$ 58,240
Statutory depletion carryforward	4,651	4,443
Alternative minimum tax credit carryforward	332	547
Asset retirement obligations	12,228	11,307
Other	2,443	1,389
Total deferred tax asset	77,705	75,926
Deferred Tax Liability:		
Oil and gas properties	(101,921)	(80,565)
Other	(5,838)	(224)
Total deferred tax liability	(107,759)	(80,789)
Net deferred tax liability	$ (30,054)	$ (4,863)

If not utilized, the Company s federal net operating loss carryforwards will expire in 2013 through 2021. The Company has significant state net operating loss carryforwards that are not included in the deferred tax asset above, as the Company does not anticipate generating taxable state income in the states in which these loss carryforwards apply. The Company has very limited state taxable income as primarily all of its revenue is generated in federal waters not subject to state income taxes.

The 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.

	Years Ended December 31, 2006	2005	2004
Income tax expense computed at the statutory federal income tax rate	35%	35%	35%
Change in valuation allowance			(84)%
Other		(1)%	
Effective income tax rate	35%	34%	(49)%

6. OTHER COMPREHENSIVE INCOME

The Company s other comprehensive income (loss) of $9.0 million, $1.6 million and $(1.9) million for the years ended December 31, 2006, 2005 and 2004 respectively, relates to the change in fair value of its derivatives. Other comprehensive income (loss) was net of income tax expense (benefit) of $4.7 million, $835,000 and ($1.0) million for the years ended December 31, 2006, 2005 and 2004, respectively.

7. LONG-TERM DEBT

Long-term debt consisted of the following at:

	December 31,	
	2006	**2005**
	(In thousands)	
Senior secured credit facility	$ 35,000	$
9.75% Senior Notes (due 2010) net of discount	189,862	187,941
Capital lease	872	1,135
Total long-term debt	225,734	189,076
Less current portion	213	263
Long-term portion	$ 225,521	$ 188,813

Senior Secured Credit Facility. On August 30, 2006, the Company closed on a four-year amended and restated senior secured credit facility underwritten by Union Bank of California, N.A. The initial borrowing base is $75 million, which will be 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 major producing fields. As of December 31, 2006 there was $35 million outstanding under the facility with a weighted average interest rate of 6.73% and $40 million was available for future borrowings. In connection with the anticipated financing of the acquisition of BP s interest in the Entrada Field, the borrowing base under this facility would be reduced to $50 million at closing until the next borrowing base redetermination date. See Note 14 for more discussion on the Entrada acquisition.

The credit facility bears interest at 0% to 0.50% above a defined base rate depending on utilization of the borrowing base or, at the option of the Company, LIBOR plus 1.375% to 2.0% 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 during 2006 was 6.24% to 8.50%.

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. In conjunction with the new senior unsecured notes, the Company issued detachable warrants to purchase 2.775 million shares of its 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 are being 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 are being amortized over the life of the notes.

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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.

As of December 31, 2006, 1.617 million of the 2.775 million detachable warrants issued with the 9.75% Senior Notes due 2010 were exercised. In addition, 265,210 of the $0.01 warrants associated with the 12% senior loans, which were redeemed in 2004, were exercised in June 2006.

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.

Loss on Early Extinguishment of Debt. In the first half of 2004, the Company completed several transactions that restructured certain debt that was maturing through 2005 resulting in a loss on early extinguishment of debt for the year ended December 31, 2004 of $3.0 million.

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.

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, 2006.

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

Year	Capital Lease Payments	Debt
2007	$ 348	$
2008	228	
2009	229	
2010	220	235,000
Thereafter	245	

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8. DERIVATIVES

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

	December 31, 2006	December 31, 2005	December 31, 2004
Amortization of derivative contract premiums	$ 150	$ 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
	$ 150	$ 6,028	$ 1,371

The change in fair value and settlements on ineffective derivative contracts in 2005 and 2004 relate to contracts that were deemed ineffective as a result of a shortfall in production volumes due to downtime resulting from damages caused by Hurricanes Katrina and Rita in 2005 and tropical storms and Hurricane Ivan in 2004. Cash settlements on effective cash flow hedges for the year ended December 31, 2006 resulted in an increase in oil and gas sales of $8.9 million. For the years ended December 31, 2005 and 2004, cash settlements on effective cash flow hedges resulted in a reduction in oil and gas sales of $10.3 million and $13.8 million, respectively.

Listed in the table below are the outstanding derivative contracts as of December 31, 2006:

Collars

Product	Volumes per Month	Quantity Type	Average Floor Price	Average Ceiling Price	Period
Oil	50,000	Bbls	$65.00	$88.75	01/07-12/07
Natural Gas	600,000	MMBtu	$ 8.00	$12.70	01/07-12/07

9. 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 SEC 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.

The Company was required to make monthly royalty payments for 2006 deepwater oil and gas production and will be required to make monthly royalty payments for 2007. With regard to the shallow water, deep natural gas royalty relief, the Company was not required to make royalty payments for 2006 and will not be required to make royalty payments for 2007.

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, 2006 excluded oil and gas reserves for Medusa that are subject to MMS royalties as a result of the average 2006 NYMEX prices for oil and gas exceeding the deepwater price thresholds. With regard to the shallow water, deep natural gas properties, there was no reduction in reserves for potential future royalties as of December 31, 2006 as a result of the average 2006 NYMEX price for gas being below the price threshold.

The Company s Entrada Field is governed by leases from the MMS. These leases granted royalty suspension without provisions for pricing thresholds for crude oil and natural gas which would require us to pay royalties to the MMS if the thresholds were exceeded by the current year average of NYMEX prices. The MMS has notified us the exclusion of the provisions occurred in error in the lease issuance process and was not the MMS s intention. Congress is considering various bills to address this issue and if a bill were to pass to amend the leases to provide thresholds for crude oil and natural gas prices the reserves for Entrada could be subject to such royalties. However, the MMS stated in their correspondence to the Company that they will continue to honor the terms of the leases as issued unless notified otherwise. This correspondence applies only to Callon s 20% working interest in the Entrada Field.

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The Company s activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect 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.

10. ASSET RETIREMENT OBLIGATIONS

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

	Twelve Months Ended	
	December 31, 2006	**December 31, 2005**
Asset retirement obligations at beginning of period	$ 38,273	$ 38,282
Accretion expense	4,960	3,549
Net profits interest accretion		331
Liabilities incurred	1,440	2,365
Liabilities settled	(16,970)	(5,184)
Revisions to estimate	13,476	(1,070)
Asset retirement obligation at end of period	41,179	38,273
Less: current retirement obligations	(14,355)	(21,660)
Long-term retirement obligations	$ 26,824	$ 16,613

Assets, primarily short-term U.S. Government securities, of approximately $6.2 million at December 31, 2006, of which $4.3 million was current, were recorded as restricted investments. These assets are held in abandonment trusts (Trusts) dedicated to pay future abandonment costs for several of the Company s oil and gas properties.

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11. 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, 2006	2005	2004
	(In thousands)		
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$ 937,698	$ 862,101	$ 802,912
Property acquisition costs	4,053	6,627	1,355
Exploration costs	73,659	46,379	26,749
Development costs	81,497	22,591	31,086
Sale of mineral interests			(1)
End of period balance	$ 1,096,907	$ 937,698	$ 862,101
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 49,065	$ 39,042	$ 34,251
Additions	19,103	18,739	16,367
Capitalized interest	6,477	5,655	4,577
Transfers to evaluated	(19,843)	(14,371)	(16,153)
End of period balance	$ 54,802	$ 49,065	$ 39,042
Accumulated depreciation, depletion and amortization-			
Beginning of period balance	$ 539,399	$ 494,453	$ 447,000
Provision charged to expense	65,283	44,946	47,453
End of period balance	$ 604,682	$ 539,399	$ 494,453

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 $24.7 million incurred in 2006, $17.8 million incurred in 2005, $3.5 million incurred in 2004 and $8.8 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 years.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $3.14, $2.39 and $2.18 for the years ended December 31, 2006, 2005, and 2004, respectively.

Under the full-cost accounting rules of the SEC, the Company reviews the carrying value of its proved oil and gas properties each quarter. Under these rules, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization 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%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full-cost ceiling amount). 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. However, if prices recover sufficiently subsequent to the balance sheet date before the release of the financial statements then use of the subsequent pricing is allowed and no write-down would be required if such pricing was used. 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 write-downs of oil and gas properties could occur in the future.

12. 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:

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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 $615,000, $557,000 and $528,000 in the years 2006, 2005 and 2004, respectively.

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 limited to a maximum of 1,200,000 shares (as amended from the original 900,000 shares) of common stock subject to outstanding awards. The 1996 Plan was amended again and approved on May 9, 2000 at the Annual Meeting of Shareholders, increasing the number of shares reserved for issuance under the 1996 plan to 2,200,000 shares. Unvested options are subject to forfeiture upon certain termination of employment events and expire 10 years from the date of grant.

In August 2006, the Board of Directors approved the award of 520,000 shares of restricted stock from the 1996 Plan. Of the 520,000 shares, 20,000 shares were granted to non-employee members of the Board of Directors and vested immediately. The remaining 500,000 shares were issued to employees of the Company with 20% vesting immediately and the remaining 80% vesting ratably over the next four years. The compensation cost with respect to the 20% that vested immediately was recognized as an expense on the grant date and the compensation cost with respect to the remaining 80% is being amortized to expense over the vesting period.

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 2006, 17,500 shares were awarded as restricted stock with 20% vesting immediately and the remaining 80% vesting ratably over the next four years. The compensation cost with respect to the 20% that vested immediately was recognized as an expense on the grant date and the compensation cost with respect to the remainging 80% is being amortized to expense over the vesting period.

2006 Stock Incentive Plan

On March 9, 2006, the Board of Directors of the Company approved the 2006 Stock Incentive Plan (2006 Plan). The 2006 Plan was approved by the shareholders at the May 4, 2006 annual meeting. Pursuant to the 2006 Plan, 500,000 shares of common stock shall be reserved for issuance upon exercise of stock options, restricted stock or other stock-based awards. In 2006, 45,000 shares were awarded as restricted stock that will vest ratably over the next four years. The compensation cost with respect to this grant is being amortized to expense over the vesting period.

13. 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, Callon 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, the Company 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.

14. SUBSEQUENT EVENTS

Subsequent to December 31, 2006, the Company entered into an agreement with BP Exploration and Production Company (BP) to purchase BP s 80% working interest in the Entrada Field for total cash consideration of $190 million. The purchase price includes $150 million payable at closing and an additional $40 million payable after the achievement of certain production milestones. The purchased interests include five federal offshore blocks at Garden Banks Blocks 738, 782, 785, 826 and 827, subject to certain depth limitations. Upon the completion of the acquisition, Callon will own a 100% working interest in the Entrada Field and will become operator. The acquisition is expected to close within the next 45 days and will add 150 Bcfe to Callon s proved undeveloped reserves.

To finance the initial $150 million payment of the purchase price, a commitment has been received from Merrill Lynch Capital Corporation to make available to Callon a 7-year, $200 million revolving credit facility secured by a lien on the Entrada properties. We plan to borrow the full commitment amount at closing to cover the required $150 million payment to BP and, expenses and fees, and the balance of the funds can be used for Entrada development costs or general corporate purposes. In connection with the closing of the financing of the acquisition of BP s interest in the Entrada Field, the borrowing base of our senior secured credit facility will be reduced to $50 million.

15. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company s proved oil and gas reserves at December 31, 2006, 2005 and 2004 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 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 9 regarding the provisions for royalty relief and the effect on reserves.

Estimated Reserves

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

Reserve Quantities

	Years Ended December 31,		
	2006	**2005**	**2004**
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	18,428	19,748	23,709
Revisions to previous estimates	(3,733)	316	(2,370)(a)
Purchase of reserves in place		71	
Extensions and discoveries	204	129	145
Production	(1,634)	(1,836)	(1,736)
End of period	13,265	18,428	19,748
Natural Gas (MMcf):			
Beginning of period	78,021	72,619	74,691
Revisions to previous estimates	(15,557)	(4,946)	2,138
Purchase of reserves in place		1,308	
Extensions and discoveries	14,550	16,808	7,177
Production	(10,977)	(7,768)	(11,387)
End of period	66,037	78,021	72,619
Proved developed reserves:			
Crude Oil (MBbls):			

Beginning of period	7,323	10,292	9,919
End of period	5,159	7,323	10,292
Natural Gas (MMcf):			
Beginning of period	30,982	33,982	31,415
End of period	36,750	30,982	33,982

(a) Includes Medusa royalty adjustment

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 reflect period-end prices (approximately $5.78 per Mcf for natural gas and $54.07 per Bbl for oil for the 2006 disclosures, $10.13 per Mcf and $55.44 per Bbl for 2005 disclosures, and $6.51 per Mcf and $36.72 per Bbl for 2004 disclosures) at each date presented with no escalation. 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,		
	2006	**2005**	**2004**
		(In thousands)	
Future cash inflows	$ 1,101,182	$ 1,814,208	$ 1,198,096
Future costs -			
Production	(243,740)	(238,321)	(231,616)
Development and net abandonment	(81,700)	(88,070)	(74,335)
Future net inflows before income taxes	775,742	1,487,817	892,145
Future income taxes	(119,685)	(379,287)	(166,284)
Future net cash flows	656,057	1,108,530	725,861
10% discount factor	(185,266)	(270,978)	(209,968)
Standardized measure of discounted future net cash flows	$ 470,791	$ 837,552	$ 515,893

Changes in Standardized Measure

	Years Ended December 31,		
	2006	**2005**	**2004**
		(In thousands)	
Standardized measure beginning of period	$ 837,552	$ 515,893	$ 519,026
Sales and transfers, net of production costs	(153,387)	(116,913)	(97,494)
Net change in sales and transfer prices, net of production costs	(347,193)	391,570	86,551
Exchange and sale of in place reserves			
Purchases, extensions, discoveries, and improved recovery, net of future production and development costs incurred	122,862	127,848	77,576
Revisions of quantity estimates	(155,342)	(17,241)	(41,314)
Accretion of discount	108,871	61,259	57,046
Net change in income taxes	187,209	(154,460)	(45,262)
Changes in production rates, timing and other	(129,781)	29,596	(40,236)
Standardized measure end of period	$ 470,791	$ 837,552	$ 515,893

At year end 2006, a downward revision was made by the Company s independent petroleum engineers to Entrada s estimated net proved reserves as of December 31, 2006 due to new performance data from analogous deepwater reservoirs.

16. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2006				
Total revenues	$45,581	$47,057	$44,878	$44,752
Income from operations	22,605	21,616	17,815	12,367
Net income	12,767	12,303	9,630	5,860
Net income per common share-basic	$ 0.66	$ 0.61	$ 0.47	$ 0.28
Net income per common share-diluted	0.60	0.57	0.45	0.27

	First Quarter	Second Quarter	Third Quarter(a)	Fourth Quarter(a)
	(In thousands, except per share data)			
2005				
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	0.46	0.46	0.17	0.20

(a) These quarters were impacted by tropical storm and hurricane activity.

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

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

ITEM 9.A CONTROLS AND PROCEDURES

The term disclosure controls and procedures is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission. Our management, including our Chief Executive Officer and Chief Financial Officer, have evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this annual report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

Management s Report On Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive and financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006 based on the frame work in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control-Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Ernst & Young LLP, our independent registered public accounting firm, has issued an attestation report on our management s assessment of the effectiveness of our internal control over financial reporting which is included herein.

Report of Independent Registered Public Accounting Firm

The Stockholders and Board of Directors
Callon Petroleum Company

We have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting, that Callon Petroleum Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Callon Petroleum Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management s assessment that Callon Petroleum Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also, in our opinion, Callon Petroleum Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Callon Petroleum Company as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2006 of Callon Petroleum Company and our report dated March 15, 2007, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
New Orleans, Louisiana
March 15, 2007

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ITEM 9.B OTHER INFORMATION

We have disclosed all information required to be disclosed in a current report on Form 8-K during the fourth quarter of the year ended December 31, 2006 in previously filed reports on Form 8-K.

PART III.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

For information concerning Item 10, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 3, 2007 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

The Company has adopted a code of ethics that applies to the Company s chief executive officer, chief financial officer and chief accounting officer. The full text of such code of ethics has been posted on the Company s website at www.callon.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at 200 North Canal Street, Natchez, Mississippi 39120.

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ITEM 11. EXECUTIVE COMPENSATION.

For information concerning Item 11, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 3, 2007 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

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