

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549
FORM 10-K**

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2009

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission File Number: 1-12074

STONE ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

State or other jurisdiction of incorporation or organization: Delaware

I.R.S. Employer Identification No. 72-1235413

625 E. Kaliste Saloom Road

Lafayette, Louisiana

(Address of principal executive offices)

70508

(Zip Code)

Registrant's telephone number, including area code: (337) 237-0410

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
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 No

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 No

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 No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

(Do not check if a smaller reporting company)

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately \$312,023,102 as of June 30, 2009 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of February 22, 2010, the registrant had outstanding 48,462,625 shares of Common Stock, par value \$.01 per share.

Documents incorporated by reference: Portions of the Definitive Proxy Statement of Stone Energy Corporation relating to the Annual Meeting of Stockholders to be held on May 21, 2010 are incorporated by reference into Part III of this Form 10-K.

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PART I

This section highlights information that is discussed in more detail in the remainder of the document. Throughout this document we make statements that are classified as “forward-looking.” Please refer to the “Forward-Looking Statements” section beginning on page 7 of this document for an explanation of these types of statements. We use the terms “Stone”, “Stone Energy”, “company”, “we”, “us” and “our” to refer to Stone Energy Corporation and its consolidated subsidiaries. Certain terms relating to the oil and gas industry are defined in “Glossary of Certain Industry Terms”, which begins on page G-1 of this Form 10-K.

ITEM 1. BUSINESS

The Company

Stone Energy is an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties located primarily in the Gulf of Mexico (“GOM”). More recently, we have made strategic investments in the deep water and deep shelf GOM, which we have targeted as important exploration areas. We are also active in the Appalachia region, where we have established a significant acreage position in the Marcellus Shale. As of December 31, 2009, our estimated proved oil and natural gas reserves were approximately 410.7 Bcfe. We were incorporated in 1993 as a Delaware corporation. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana.

Strategy and Operational Overview

Our business strategy is to increase production, cash flow and reserves through the acquisition, exploration, exploitation, development and operation of properties located offshore on the GOM shelf, in the deep water GOM and onshore in the Appalachia region. We plan to utilize cash flow from our producing GOM shelf properties to fund exploration and development of higher impact properties in the deep water and deep shelf GOM and lower risk repeatable drilling opportunities in Appalachia.

Gulf of Mexico — Conventional Shelf (Including Onshore Louisiana)

Our conventional shelf strategy is to apply the latest geophysical interpretation tools to identify underdeveloped properties and the latest production techniques to increase production attributable to these properties. Prior to acquiring a property, we perform a thorough geological, geophysical and engineering analysis of the property to formulate a comprehensive development plan. We also employ our extensive technical database, which includes both 3-Dimensional and 4-Component seismic data. After we acquire a property, we seek to increase cash flow from existing reserves and establish additional proved reserves through the drilling of new wells, workovers and recompletions of existing wells and the application of other techniques designed to increase production.

Gulf of Mexico — Deep Water/ Deep Shelf

We believe that the deep water of the GOM is an important exploration area, even though it involves high risk, high costs and substantial lead time to develop infrastructure. We have made a significant investment in seismic data and leasehold interests and have assembled a technical team with prior geological, geophysical and engineering experience in the deep water arena to evaluate potential opportunities.

Our current property base also contains multiple deep shelf exploration opportunities in the GOM, which are defined as prospects below 15,000 feet. The deep shelf presents higher risk with high potential opportunities usually with existing infrastructure, which shortens the lead time to production.

Appalachia

During 2006, we began securing leasehold interests in the Appalachia regions of Pennsylvania and West Virginia. As of February 25, 2010, we have secured leasehold interests in approximately 42,000 net acres and have six vertical wells that are currently on production and another eight wells that are in various stages of drilling or completion waiting on hook-up. We expect to add leasehold interests and drill additional horizontal and vertical wells to further expand our interests in Appalachia.

Rocky Mountain Region

On June 29, 2007, we completed the sale of substantially all of our Rocky Mountain Region properties and related assets to Newfield Exploration Company. We maintain working interests in several undeveloped plays in the Rocky Mountain Region, which totaled approximately 81,000 net acres as of February 25, 2010.

Oil and Gas Marketing

Our oil and natural gas production is sold at current market prices under short-term contracts. Shell Trading (US) Company, Conoco, Inc., Sequent Energy Management LP and Hess Corporation, each accounted for between 11% - 34% of our oil and natural gas revenue generated during the year ended December 31, 2009. No other purchaser accounted for 10% or more of our total oil and natural gas revenue during 2009. We do not believe that the loss of any of our major purchasers would result in a material adverse effect on our ability to market future oil and gas production. From time to time, we may enter into transactions that hedge the price of oil and natural gas. See **“Item 7A. Quantitative and Qualitative Disclosures About Market Risk – Commodity Price Risk.”**

Competition and Markets

Competition in the Gulf Coast Basin, the deep water and deep shelf GOM and the Appalachia region is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete. See **“Item 1A. Risk Factors – Competition within our industry may adversely affect our operations.”**

The availability of a ready market for and the price of any hydrocarbons produced will depend on many factors beyond our control, including but not limited to the amount of domestic production and imports of foreign oil and liquefied natural gas, the marketing of competitive fuels, the proximity and capacity of oil and natural gas pipelines, the availability of transportation and other market facilities, the demand for hydrocarbons, the effect of federal and state regulation of allowable rates of production, taxation and the conduct of drilling operations, and federal regulation of oil and natural gas. In addition, the restructuring of the natural gas pipeline industry eliminated the gas purchasing activity of traditional interstate gas transmission pipeline buyers. Producers of natural gas have therefore been required to develop new markets among gas marketing companies, end users of natural gas and local distribution companies. All of these factors, together with economic factors in the marketing arena, generally may affect the supply of and/or demand for oil and natural gas and thus the prices available for sales of oil and natural gas.

Regulation

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations.

Various aspects of our oil and natural gas operations are regulated by administrative agencies of the states where we conduct operations and by certain agencies of the federal government for operations on federal leases. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions requiring permits for the drilling of wells and maintaining bonding requirements in order to drill or operate wells, and provisions relating to the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the number of wells that may be drilled in an area and the unitization or pooling of oil and natural gas properties. In this regard, some states can order the pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratable or fair apportionment of production from fields and individual wells.

Certain operations that we conduct are on federal oil and gas leases, which are administered by the Bureau of Land Management (the “BLM”) and the Minerals Management Service (the “MMS”). These leases contain relatively standardized terms and require compliance with detailed BLM and MMS regulations and orders pursuant to various federal laws, including the Outer Continental Shelf Lands Act (the “OCSLA”) (which are subject to change by the applicable agency). Many onshore leases contain stipulations limiting activities that may be conducted on the lease. Some stipulations are unique to particular geographic areas and may limit the times during which activities on the lease may be conducted, the manner in which certain activities may be conducted or, in some cases, may ban any surface activity. For offshore operations, lessees must obtain MMS approval for exploration, development and production plans prior to the commencement of such operations. In addition to permits required from other agencies (such as the U.S. Environmental Protection Agency), lessees must obtain a permit from the BLM or the MMS, as applicable, prior to the commencement of drilling, and comply with regulations governing, among other things, engineering and construction specifications for production facilities, safety procedures, plugging and abandonment of wells on the Outer Continental Shelf (the “OCS”) of the GOM, calculation of royalty payments and the valuation of production for this purpose, and removal of facilities. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the MMS exempts the lessee from such obligations. The cost of such

bonds or other surety can be substantial, and we can provide no assurance that we can continue to obtain bonds or other surety in all cases. Under certain circumstances, the BLM or MMS, as applicable, may require our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition and operations.

In 2005, the U.S. Congress enacted the Energy Policy Act of 2005 (“EPAAct 2005”). Among other matters, EPAAct 2005 amends the Natural Gas Act (“NGA”) to make it unlawful for “any entity”, including otherwise non-jurisdictional producers such as Stone Energy, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the Federal Energy Regulatory Commission (“FERC”), in contravention of rules prescribed by the FERC. In 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to \$1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction. It therefore reflects a significant expansion of the FERC’s enforcement authority. Stone Energy does not anticipate it will be affected any differently than other producers of natural gas.

In 2007, the FERC issued rules requiring that any market participant, including a producer such as Stone Energy, that engages in sales for resale or purchases for resale of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report such sales or purchases to the FERC, beginning on May 1, 2009. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. In 2008 the FERC issued its order on rehearing which largely approved the existing rules, except the FERC exempted from the reporting requirement certain types of purchases and sales, including purchases and sales of unprocessed gas and bundled sales of gas made pursuant to state regulated retail tariffs. Also, the FERC clarified that other end use purchases and sales are not exempt from the reporting requirements. The monitoring and reporting required by these rules have increased our administrative costs. Stone Energy does not anticipate it will be affected any differently than other producers of natural gas.

Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. In recent years, the FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of FERC Order No. 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas supplies. In many instances, the results of FERC Order No. 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines’ traditional role as wholesalers of natural gas in favor of providing only storage and transportation services.

Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by the U.S. Congress, states, the FERC and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the oil and natural gas industry has been heavily regulated. We can give no assurance that the regulatory approach currently pursued by the FERC or any other agency will continue indefinitely. We do not anticipate, however, that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect on our financial condition, results of operations or competitive position. No portion of our business is subject to renegotiation of profits or termination of contracts or subcontracts at the election of the federal government.

Environmental Regulation

As a lessee and operator of onshore and offshore oil and gas properties in the United States, we are subject to stringent federal, state and local laws and regulations relating to environmental protection, as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas industry operations, are released into the environment. Compliance with these laws and regulations require the acquisition of permits authorizing air emissions and wastewater discharge from operations and can affect the location or size of wells and facilities, limit or prohibit the extent to which exploration and development may be allowed, and require proper closure of wells and restoration of properties that are being abandoned. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, imposition of remedial obligations, incurrence of capital costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production operations or the disposal of substances generated in connection with oil and gas industry operation.

We currently operate or lease, and have in the past operated or leased, a number of properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such hydrocarbons or wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or wastes was not under our control. These properties and the hydrocarbons and wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability, without regard to fault or the legality of the original conduct, that could require us to remove or remediate previously disposed wastes or environmental contamination, or to perform remedial plugging or pit closure to prevent future contamination.

The Oil Pollution Act of 1990 (“OPA”) and regulations adopted pursuant to OPA impose a variety of requirements related to the prevention of and response to oil spills into waters of the United States, including the OCS. The OPA subjects owners of oil handling facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages. OPA also requires owners and operators of offshore oil production facilities such as us to establish and maintain evidence of financial responsibility of at least \$35 million to cover costs that could be incurred in responding to an oil spill. We believe that we are in substantial compliance with the requirements of OPA, and that these requirements are not any more burdensome to us than they are to other similarly situated oil and gas companies.

In June 2009, the U.S. House of Representatives passed a bill—the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” (“ACESA”)—to control and reduce the emission of “greenhouse gases” (“GHGs”), such as carbon dioxide and methane, that may be contributing to warming of the Earth’s atmosphere and other climatic changes. The U.S. Senate is currently considering similar legislation that seeks to reduce emission of GHGs in the United States through the granting of emission allowances which would gradually be decreased over time. Moreover, nearly half of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of GHGs. Also, on December 15, 2009, the U.S. Environmental Protection Agency (“EPA”) officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles that could also lead to the imposition of GHG emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. Although the vast majority of our facilities were not subject to the EPA’s GHG reporting rule adopted in September 2009, EPA has indicated that it is evaluating whether the rule should be applied to oil and gas production activities, perhaps on a field-wide basis. While it is not possible at this time to fully predict how legislation or new regulations that may be adopted in the United States to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on demand for the oil and natural gas that we produce.

The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act (“SDWA”), to subject hydraulic fracturing operations to regulation under the SDWA and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and gas production. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for us to perform hydraulic fracturing, which is an important component of well development. Any impairment of our ability to perform hydraulic fracturing could have an adverse effect on our ability to produce oil and gas from new wells.

We have made, and will continue to make, expenditures in our effort to comply with environmental laws and regulations. We believe that we are in substantial compliance with applicable environmental laws and regulations in effect and that continued compliance with existing requirements will not have a material adverse impact on us. However, we also believe that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards and, thus, we cannot give any assurance that we will not be adversely affected in the future.

We have established internal guidelines to be followed in order to comply with environmental laws and regulations in the United States. We employ a safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although we maintain pollution insurance to cover a portion of the costs of cleanup operations, public liability and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future. To date, we believe that compliance with existing requirements of such governmental bodies has not had a material effect on our operations.

Employees

On February 22, 2010, we had 313 full time employees. We believe that our relationships with our employees are satisfactory. None of our employees are covered by a collective bargaining agreement. We utilize the services of independent contractors to perform various daily operational duties.

Available Information

We make available free of charge on our Internet web site (www.stoneenergy.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the Securities and Exchange Commission (the "SEC"). We also make available on our Internet web site our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, which have been approved by our board of directors. We will make timely disclosure by a Current Report on Form 8-K and on our web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: Chief Financial Officer, Stone Energy Corporation, P.O. Box 52807, Lafayette, LA 70505. The annual CEO certification required by Section 303A.12 of the New York Stock Exchange Listed Company Manual was submitted on June 8, 2009.

Forward-Looking Statements

The information in this Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical or current facts, that address activities, events, outcomes and other matters that we plan, expect, intend, assume, believe, budget, predict, forecast, project, estimate or anticipate (and other similar expressions) will, should or may occur in the future are forward-looking statements. These forward-looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Form 10-K.

Forward-looking statements appear in a number of places and include statements with respect to, among other things:

- any expected results or benefits associated with our acquisitions;
- estimates of our future oil and natural gas production, including estimates of any increases in oil and gas production;
- planned capital expenditures and the availability of capital resources to fund capital expenditures;
- our outlook on oil and gas prices;
- estimates of our oil and gas reserves;
- any estimates of future earnings growth;
- the impact of political and regulatory developments;
- our outlook on the resolution of pending litigation and government inquiry;
- estimates of the impact of new accounting pronouncements on earnings in future periods;
- our future financial condition or results of operations and our future revenues and expenses;
- estimates of future income taxes; and
- our business strategy and other plans and objectives for future operations.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and marketing of oil and natural gas. These risks include, among other things:

- commodity price volatility;
- domestic and worldwide economic conditions;
- the availability of capital on economic terms to fund our capital expenditures and acquisitions;
- our level of indebtedness;

- declines in the value of our oil and gas properties resulting in a decrease in our borrowing base under our credit facility and ceiling test write-downs and impairments;
- our ability to replace and sustain production;
- the impact of a financial crisis on our business operations, financial condition and ability to raise capital;
- the ability of financial counterparties to perform or fulfill their obligations under existing agreements;
- third party interruption of sales to market;
- inflation;
- lack of availability of goods and services;
- regulatory and environmental risks associated with drilling and production activities;
- drilling and other operating risks;
- unsuccessful exploration and development drilling activities;
- hurricanes and other weather conditions;
- the adverse effects of changes in applicable tax, environmental and other regulatory legislation;
- the uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures; and
- the other risks described in this Form 10-K.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 1A. RISK FACTORS

Our business is subject to a number of risks including, but not limited to, those described below:

Oil and natural gas prices are volatile. Declines in commodity prices have adversely affected, and in the future may adversely affect, our financial condition and results of operations, cash flows, access to the capital markets, and ability to grow.

Our revenues, cash flows, profitability and future rate of growth substantially depend upon the market prices of oil and natural gas. Prices affect our cash flow available for capital expenditures and our ability to access funds under our bank credit facility and through the capital markets. The amount available for borrowing under our bank credit facility is subject to a borrowing base, which is determined by our lenders taking into account our estimated proved reserves and is subject to periodic redeterminations based on pricing models determined by the lenders at such time. The decline in oil and natural gas prices in 2009 has impacted the value of our estimated proved reserves and, in turn, the market values used by our lenders to determine our borrowing base. If commodity prices decline in the future, the decline could have adverse effects on our reserves and borrowing base.

The prices we receive for our oil and natural gas depend upon factors beyond our control, including among others:

- changes in the supply of and demand for oil and natural gas;
- market uncertainty;
- the level of consumer product demands;
- hurricanes and other weather conditions;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuels;
- political and economic conditions in oil producing countries, particularly those in the Middle East, Russia, South America and Africa;
- actions by the Organization of Petroleum Exporting Countries (“OPEC”);
- the foreign supply of oil and natural gas;
- the price of oil and gas imports; and
- overall domestic and foreign economic conditions.

These factors make it very difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not long-term fixed price contracts. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other.

We may not be able to replace production with new reserves.

In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. Approximately 99.6% of our estimated proved reserves at December 31, 2009 and 100% of our production during 2009 were associated with our Gulf Coast Basin properties. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production is highly dependent upon our level of success in finding or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. We cannot assure you that our future exploitation, exploration, development, and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. Further, the current economic crisis has adversely impacted our ability to obtain financing to fund acquisitions and has lowered the level of activity and depressed values in the oil and natural gas property sales market.

Our actual recovery of reserves may substantially differ from our proved reserve estimates.

This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. Additionally, our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this document and the information incorporated by reference. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that any present value of future net cash flows from our producing reserves contained in this Form 10-K represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2009 on average 12-month prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. At December 31, 2009, approximately 22% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

We require substantial capital expenditures to conduct our operations and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to fund our planned capital expenditures.

We spend and will continue to spend a substantial amount of capital for the acquisition, exploration, exploitation, development and production of oil and gas reserves. If low oil and natural gas prices, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, we may be limited in our ability to fund the capital necessary to complete our capital expenditures program. In addition, if our borrowing base under our credit facility is redetermined to a lower amount, this could adversely affect our ability to fund our planned capital expenditures. After utilizing our available sources of financing, we may be forced to raise additional debt or equity proceeds to fund such capital expenditures. We cannot assure you that additional debt or equity financing will be available or cash flows provided by operations will be sufficient to meet these requirements.

A financial crisis may impact our business and financial condition. A financial crisis may adversely impact our ability to obtain funding under our current bank credit facility or in the capital markets.

The credit crisis and related turmoil in the global financial systems have had an impact on our business and our financial condition. An economic crisis could reduce the demand for oil and natural gas and put downward pressure on the prices for oil and natural gas. Historically, we have used our cash flow from operations and borrowings under our bank credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions. In the future, we may not be able to access adequate funding under our bank credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. In addition, we may face limitations on our ability to access the debt and equity capital markets and complete asset sales, an increased counterparty credit risk on our derivatives contracts and the requirement by contractual counterparties of us to post collateral guaranteeing performance.

Our debt level and the covenants in the current and any future agreements governing our debt could negatively impact our financial condition, results of operations and business prospects.

The terms of the current agreements governing our debt impose significant restrictions on our ability to take a number of actions that we may otherwise desire to take, including:

- incurring additional debt;
- paying dividends on stock, redeeming stock or redeeming subordinated debt;
- making investments;
- creating liens on our assets;
- selling assets;
- guaranteeing other indebtedness;
- entering into agreements that restrict dividends from our subsidiary to us;
- merging, consolidating or transferring all or substantially all of our assets; and
- entering into transactions with affiliates.

Our level of indebtedness, and the covenants contained in current and future agreements governing our debt, could have important consequences on our operations, including:

- making it more difficult for us to satisfy our obligations under the indentures or other debt and increasing the risk that we may default on our debt obligations;
- requiring us to dedicate a substantial portion of our cash flow from operating activities to required payments on debt, thereby reducing the availability of cash flow for working capital, capital expenditures and other general business activities;
- limiting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and other general business activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- detracting from our ability to successfully withstand a downturn in our business or the economy generally;
- placing us at a competitive disadvantage against other less leveraged competitors; and
- making us vulnerable to increases in interest rates, because debt under our credit facility is at variable rates.

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Our borrowing base under our bank credit facility, which is redetermined semi-annually, is based on an amount established by the bank group after its evaluation of our proved oil and gas reserve values. Our borrowing base is scheduled to be redetermined by May 2010. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our bank debt.

We may not have sufficient funds to make such repayments. If we are unable to repay our debt out of cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow from operating activities to pay the interest on our debt or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt. The terms of our debt, including our credit facility and our indentures, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering, refinancing or sale of assets. We cannot assure you that any such offering, refinancing or sale of assets can be successfully completed.

We have experienced significant shut-ins and losses of production due to the effects of hurricanes in the Gulf of Mexico.

Approximately 99.6% of our estimated proved reserves at December 31, 2009 and 100% of our production during 2009 were associated with our Gulf Coast Basin properties. Accordingly, if the level of production from these properties substantially declines, it could have a material adverse effect on our overall production level and our revenue. We are particularly vulnerable to significant risk from hurricanes and tropical storms in the Gulf of Mexico. During 2009 and 2008, we experienced production deferrals due to Hurricanes Gustav and Ike. During 2007, 2006 and 2005, we experienced production deferrals due to Hurricanes Katrina and Rita, and during 2004, we experienced production deferrals due to Hurricane Ivan. We are unable to predict what impact future hurricanes and tropical storms might have on our future results of operations and production.

The marketability of our production depends mostly upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and processing facilities.

The marketability of our production depends upon the availability, proximity, operation and capacity of oil and natural gas gathering systems, pipelines and processing facilities. The unavailability or lack of capacity of these systems and facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Federal, state and local regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand could adversely affect our ability to produce and market our oil and natural gas. If market factors changed dramatically, the financial impact on us could be substantial. The availability of markets and the volatility of product prices are beyond our control and represent a significant risk.

We may not receive payment for a portion of our future production.

We may not receive payment for a portion of our future production. We have attempted to diversify our sales and obtain credit protections such as parental guarantees from certain of our purchasers. The tightening of credit in the financial markets may make it more difficult for customers to obtain financing and, depending on the degree to which this occurs, there may be a material increase in the nonpayment and nonperformance by customers. We are unable to predict, however, what impact the financial difficulties of certain purchasers may have on our future results of operations and liquidity.

Lower oil and gas prices and other factors have resulted, and in the future may result, in ceiling test write-downs and other impairments of our asset carrying values.

We use the full cost method of accounting for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost method of accounting, we compare, at the end of each financial reporting period for each cost center, the present value of estimated future net cash flows from proved reserves (based on a 12-month average hedge adjusted commodity price and excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties, net of related deferred taxes. We refer to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the estimated discounted future net cash flows. A write-down of oil and gas properties does not impact cash flow from operating activities, but does reduce net income. We also assess the carrying amount of goodwill when events occur that may indicate an impairment exists. These events include, for example, a significant decline in oil and gas prices or a decline in our market capitalization. We recorded an impairment of all our goodwill of approximately \$466 million for the year ended December 31, 2008. The risk that we will be required to write down the carrying value of oil and gas properties and goodwill increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves or our undeveloped property values, or if estimated future development costs increase. For example, oil and natural gas prices declined significantly throughout the second half of 2008 and into 2009. We recorded a non-cash ceiling test impairment of approximately \$1.3 billion for the year ended December 31, 2008 and approximately \$505.1 million for the year ended December 31, 2009. Volatility in commodity prices, poor conditions in the global economic markets and other factors could cause us to record additional write-downs of our oil and natural gas properties and other assets in the future and incur additional charges against future earnings.

There are uncertainties in successfully integrating our acquisitions.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results.

Part of our strategy includes drilling in new or emerging plays. As a result, our drilling in these areas is subject to greater risk and uncertainty.

We have made initial investments in acreage and wells in Appalachia. These activities are more uncertain than drilling in areas that are developed and have established production. Our operations in Appalachia are still in the early stages and, to date, we have booked a limited amount of proved reserves associated with our properties in Appalachia. Because emerging plays and new formations have limited or no production history, we are less able to use past drilling results to help predict future results. The lack of historical information may result in not being able to fully execute our expected drilling programs in these areas or the return on investment in these areas may turn out not to be as attractive as anticipated. We cannot assure you that our future drilling activities in Appalachia or other emerging plays will be successful, or if successful will achieve the resource potential levels that we currently anticipate based on the drilling activities that have been completed or achieve the anticipated economic returns based on our current cost models.

Our operations are subject to numerous risks of oil and gas drilling and production activities.

Oil and gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reserves will be found. The cost of drilling and completing wells is often uncertain. Oil and gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- hurricanes and other weather conditions;
- shortages in experienced labor; and
- shortages or delays in the delivery of equipment.

The prevailing prices of oil and natural gas also affect the cost of and the demand for drilling rigs, production equipment and related services. We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenue after operating and other costs to recoup drilling costs.

Our industry experiences numerous operating risks.

The exploration, development and production of oil and gas properties involves a variety of operating risks including the risk of fire, explosions, blowouts, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, pipeline ruptures or discharges of toxic gases. Additionally, our offshore operations are subject to the additional hazards of marine operations, such as capsizing, collision and adverse weather and sea conditions, including the effects of hurricanes.

We have begun to explore for natural gas and oil in the deep waters of the GOM (water depths greater than 2,000 feet) where operations are more difficult and more expensive than in shallower waters. Our deep water drilling and operations require the application of recently developed technologies that involve a higher risk of mechanical failure. The deep waters of the GOM often lack the physical infrastructure and availability of services present in the shallower waters. As a result, deep water operations may require a significant amount of time between a discovery and the time that we can market the oil and gas, increasing the risks involved with these operations.

If any of these industry-operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations.

We may not be insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot assure you that our insurance will be adequate to cover losses or liabilities. We experienced Gulf of Mexico production interruption in 2005, 2006 and 2007 from Hurricanes Katrina and Rita and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable and may elect none or minimal insurance coverage. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse affect on our financial condition and operations.

Terrorist attacks aimed at our facilities could adversely affect our business.

The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack at our facilities, or those of our purchasers, could have a material adverse effect on our financial condition and operations.

Competition within our industry may adversely affect our operations.

Competition in the Gulf Coast Basin and the Appalachia region is intense, particularly with respect to the acquisition of producing properties and undeveloped acreage. We compete with major oil and gas companies and other independent producers of varying sizes, all of which are engaged in the acquisition of properties and the exploration and development of such properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours, which may adversely affect our ability to compete.

Our oil and gas operations are subject to various U.S. federal, state and local governmental regulations that materially affect our operations.

Our oil and gas operations are subject to various U.S. federal, state and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions. Regulated matters include: permits for exploration, development and production operations; limitations on our drilling activities in environmentally sensitive areas, such as wetlands and restrictions on the way we can release materials into the environment; bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs; reports concerning operations, the spacing of wells and unitization and pooling of properties; and taxation. Failure to comply with these laws and regulations can result in the assessment of administrative, civil, or criminal penalties, the issuance of remedial obligations, and the imposition of injunctions limiting or prohibiting certain of our operations. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies have restricted the rates of flow of oil and gas wells below actual production capacity. In addition, the OPA requires operators of offshore facilities such as us to prove that they have the financial capability to respond to costs that may be incurred in connection with potential oil spills. Under OPA and other federal and state environmental statutes like the federal Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”) and Resource Conservation and Recovery Act (“RCRA”), owners and operators of certain defined onshore and offshore facilities are strictly liable for spills of oil and other regulated substances, subject to certain limitations. Consequently, a substantial spill from one of our facilities subject to laws such as OPA, CERCLA and RCRA could require the expenditure of additional, and potentially significant, amounts of capital, or could have a material adverse effect on our earnings, results of operations, competitive position or financial condition. Federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas, by-products from oil and gas and other substances, and materials produced or used in connection with oil and gas operations. We cannot predict the ultimate cost of compliance with these requirements or their impact on our earnings, operations or competitive position.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon key management and technical personnel. We cannot assure you that individuals will remain with us for the immediate or foreseeable future. The unexpected loss of the services of one or more of these individuals could have an adverse effect on us.

Hedging transactions may limit our potential gains or become ineffective.

In order to manage our exposure to price risks in the marketing of our oil and natural gas, we periodically enter into oil and gas price hedging arrangements with respect to a portion of our expected production. Our hedging policy provides that, without prior approval of our board of directors, generally not more than 50% of our estimated production quantities may be hedged. These arrangements may include futures contracts on the New York Mercantile Exchange (“NYMEX”). While intended to reduce the effects of volatile oil and gas prices, such transactions, depending on the hedging instrument used, may limit our potential gains if oil and gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

- our production is less than expected or is shut-in for extended periods due to hurricanes or other factors;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform the contracts;
- a sudden, unexpected event materially impacts oil or natural gas prices; or
- we are unable to market our production in a manner contemplated when entering into the hedge contract.

Our hedging transactions will impact our earnings in various ways. Due to the volatility of oil and natural gas prices, we may have to recognize mark-to-market gains and losses on derivative instruments as the estimated fair value of our commodity derivative instruments is subject to significant fluctuations from period to period. The amount of any actual gains or losses recognized will likely differ from our period to period estimates and will be a function of the actual price of the commodities on the settlement date of the derivative instrument. We expect that commodity prices will continue to fluctuate in the future and, as a result, our periodic financial results will continue to be subject to fluctuations related to our derivative instruments.

Currently, some of our outstanding commodity derivative instruments are with certain lenders or affiliates of the lenders under our bank credit facility. Our existing derivative agreements with our lenders are secured by the security documents executed by the parties under our bank credit facility. Future collateral requirements for our commodity hedging activities are uncertain and will depend on the arrangements we negotiate with the counterparty and the volatility of oil and natural gas prices and market conditions.

Our Certificate of Incorporation and Bylaws have provisions that discourage corporate takeovers and could prevent stockholders from realizing a premium on their investment.

Certain provisions of our Certificate of Incorporation and Bylaws and the provisions of the Delaware General Corporation Law may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts. Our board of directors are elected by plurality voting. Also, our Certificate of Incorporation authorizes our board of directors to issue preferred stock without stockholder approval and to set the rights, preferences and other designations, including voting rights of those shares, as the board may determine. Additional provisions include restrictions on business combinations and the availability of authorized but unissued common stock. These provisions, alone or in combination with each other, may discourage transactions involving actual or potential changes of control, including transactions that otherwise could involve payment of a premium over prevailing market prices to stockholders for their common stock.

Resolution of litigation could materially affect our financial position and results of operations.

We have been named as a defendant in certain lawsuits (See “**Item 3. Legal Proceedings**”). In some of these suits, our liability for potential loss upon resolution may be mitigated by insurance coverage. To the extent that potential exposure to liability is not covered by insurance or insurance coverage is inadequate, we could incur losses that could be material to our financial position or results of operations in future periods.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Among the changes contained in President Obama’s budget proposal for fiscal year 2011, released by the White House on February 1, 2010, is the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operation.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In June 2009, the U.S. House of Representatives passed a bill—the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” (“ACESA”)—to control and reduce the emission of “greenhouse gases” (“GHGs”), such as carbon dioxide and methane, that may be contributing to warming of the Earth’s atmosphere and other climatic changes. The Senate is currently considering similar legislation that seeks to reduce emission of GHGs in the United States through the granting of emission allowances which would gradually be decreased over time. Moreover, nearly half of the states, either individually or through multi-state initiatives, already have begun implementing legal measures to reduce emissions of GHGs. Also, on December 15, 2009, the U.S. Environmental Protection Agency (“EPA”) officially published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. In late September 2009, the EPA had proposed two sets of regulations in

anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles that could also lead to the imposition of GHG emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. Although the vast majority of our facilities were not subject to the EPA's GHG reporting rule adopted in September 2009, EPA has indicated that it is evaluating whether the rule should be applied to oil and gas production activities, perhaps on a field-wide basis. While it is not possible at this time to fully predict how legislation or new regulations that may be adopted in the United States to address GHG emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have an adverse effect on demand for the oil and natural gas that we produce.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress currently is considering broad financial regulatory reform legislation that among other things would impose comprehensive regulation on the over-the-counter ("OTC") derivatives marketplace and could affect the use of derivatives in hedging transactions. The financial regulatory reform bill adopted by the House of Representatives on December 11, 2009, would subject swap dealers and "major swap participants" to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also would require central clearing for transactions entered into between swap dealers or major swap participants. For these purposes, a major swap participant generally would be someone other than a dealer who maintains a "substantial" net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk, or whose positions create substantial net counterparty exposure that could have serious adverse effects on the financial stability of the U.S. banking system or financial markets. The House-passed bill also would provide the Commodity Futures Trading Commission ("CFTC") with express authority to impose position limits for OTC derivatives related to energy commodities. Separately, in late January, 2010, the CFTC proposed regulations that would impose speculative position limits for certain futures and option contracts in natural gas, crude oil, heating oil, and gasoline. These proposed regulations would make an exemption available for certain *bona fide* hedging of commercial risks. Although it is not possible at this time to predict whether or when Congress will act on derivatives legislation or the CFTC will finalize its proposed regulations, any laws or regulations that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act ("SDWA"), to subject hydraulic fracturing operations to regulation under the SDWA and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and gas production. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for us to perform hydraulic fracturing, which is an important component of well development. Any impairment of our ability to perform hydraulic fracturing could have an adverse effect on our ability to produce oil and gas from new wells.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As of February 25, 2010, our property portfolio consisted of 71 active properties and 100 primary term leases in the Gulf Coast Basin and 5 active properties in the Appalachia region. We serve as operator on 83% of our active properties. The properties that we operate accounted for 90% of our year-end 2009 estimated proved reserves. This high operating percentage allows us to better control the timing, selection and costs of our drilling and production activities.

Oil and Natural Gas Reserves

In December 2008, the SEC issued a final rule, "Modernization of Oil and Gas Reporting," which adopts revisions to the SEC's oil and gas reporting requirements. Among other things, the revisions: (1) replace the single-day year-end pricing with a twelve-month average pricing assumption; (2) permit the reporting of probable and possible reserves in addition to the existing requirement to disclose proved reserves; (3) allow the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (4) require the disclosure of the independence and qualifications of third party preparers of reserves; and (5) require the filing of reports when a third party is relied upon to prepare or audit reserve estimates. We were required to adopt the provisions of the new rule as of December 31, 2009 for this 2009 Annual Report on Form 10-K.

We have various internal controls in place to provide reasonable assurance of compliance with SEC rules in the determination of estimated reserves. For non-year-end and quarterly reserve estimates we utilize our internal staff to prepare the estimates. For year-end estimates we utilize the services of outside engineering consultants. Our Director of Strategic Planning is primarily responsible for the process of reserve preparation. For purposes of reserve preparation he reports directly to a reserves committee of our Board of Directors which provides oversight in regards to reserve estimation and analysis. Our Director of Strategic Planning is a petroleum engineer with extensive experience in reservoir analysis. He oversees an internal program under which all personnel involved in the reserves estimation process receive formal training in SEC requirements for reporting estimated reserves. We have a written policy and guidelines for booking estimated proved reserves that is provided to all personnel involved in the reserves estimation process. These programs and policies have been updated to reflect the requirements under the SEC's new rule. Estimates of our proved reserves at December 31, 2009 were prepared by Netherland, Sewell & Associates, Inc. ("NSA"), a nationally recognized engineering firm. NSA provides a complete range of geological, geophysical, petrophysical and engineering services and has the technical experience and ability to perform these services in any of the onshore and offshore oil and gas producing areas of the world. NSA currently has a technical staff of approximately 70 professionals who are intimately familiar with recognized industry reserve and resource definitions, specifically those set forth by the SEC. NSA's letter is filed as an exhibit to this Annual Report on Form 10-K.

The following table sets forth our estimated proved oil and gas reserves (99.6% of which are located in the Gulf Coast Basin and 0.4% are located in the Appalachia region) as of December 31, 2009.

Summary of Oil and Gas Reserves as of December 31, 2009 Based on Average Fiscal-Year Prices

	Oil (MBbls)	Natural Gas (MMcf)	Oil and Natural Gas (MMcfe)
Reserves Category:			
PROVED			
Developed	24,379	172,452	318,729
Undeveloped	7,957	44,242	91,982
TOTAL PROVED	32,336	216,694	410,711

Proved undeveloped reserves ("PUD's") at December 31, 2009 totaled approximately 92.0 Bcfe, or 22% of our total estimated proved oil and gas reserves. In 2009, we removed one PUD operation from reserves that had been included in our estimated proved reserves for over five years. Approximately 90% of our PUD's at December 31, 2009 are expected to be drilled within the next five years. The remaining PUD's are waiting on the depletion of downhole reservoirs before the uphole undeveloped reservoir can be developed. We had no material conversions of PUD's into proved developed reserves during 2009. The 2009 average 12-month oil and gas prices net of differentials were \$58.95 per barrel of oil and \$3.49 per Mcf of gas.

The following represents additional information on individually significant properties:

Field Name	Location	2009	December 31, 2009	Nature of Interest
		Production (MMcfe)	Estimated Proved Reserves (MMcfe)	
Mississippi Canyon Block 109	GOM Shelf	6,256	77,345	Working
Ship Shoal Block 113	GOM Shelf	3,894	56,750	Working
Ewing Bank Block 305	GOM Shelf	11,050	33,921	Working
Main Pass Block 288	GOM Shelf	5,102	23,406	Working
South Pelto Block 22	GOM Shelf	6,958	21,009	Working

The following table discloses information regarding the sensitivity of our estimated total proved oil and gas reserves to prices.

Sensitivity of Reserves to Prices				
December 31, 2009 Estimated Proved Reserves				
Price Case	Oil (MBbls)	Natural Gas (MMcf)	Oil and Natural Gas (MMcfe)	Standardized Measure (\$ in thousands)
SEC pricing (a)	32,336	216,694	410,711	\$614,987
Scenario 1 (b)	29,039	173,545	347,777	282,182
Scenario 2 (c)	33,345	233,614	433,686	883,114

- (a) This case represents pricing under SEC rules. The 2009 average 12-month oil and gas prices net of differentials were \$58.95 per barrel of oil and \$3.49 per Mcf of gas.
- (b) Scenario 1 estimates total proved reserves assuming an average oil price \$10.00 lower and an average gas price \$1.00 lower than prices required to be used under the SEC's rules.
- (c) Scenario 2 estimates total proved reserves assuming an average oil price \$10.00 higher and an average gas price \$1.00 higher than prices required to be used under the SEC's rules.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond the control of the producer. The reserve data set forth herein only represents estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data and the interpretation of that data by geological engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, these revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geological success, prices, future production levels, operating costs, development costs and income taxes that may not prove to be correct. Predictions about prices and future production levels are subject to great uncertainty, and the meaningfulness of these estimates depends on the accuracy of the assumptions upon which they are based.

As an operator of domestic oil and gas properties, we have filed Department of Energy Form EIA-23, "Annual Survey of Oil and Gas Reserves," as required by Public Law 93-275. There are differences between the reserves as reported on Form EIA-23 and as reported herein. The differences are attributable to the fact that Form EIA-23 requires that an operator report the total reserves attributable to wells that it operates, without regard to percentage ownership (*i.e.*, reserves are reported on a gross operated basis, rather than on a net interest basis) or non-operated wells in which it owns an interest.

Acquisition, Production and Drilling Activity

Acquisition and Development Costs. The following table sets forth certain information regarding the costs incurred in our acquisition, development and exploratory activities in the United States and China during the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Acquisition costs, net of sales of unevaluated properties	\$9,072	\$1,830,468	\$18,730
Development costs (1).....	199,375	59,586	154,507
Exploratory costs.....	78,582	146,529	10,966
Sale of Rocky Mountain Region properties	-	-	(1,363,939)
Subtotal	287,029	2,036,583	(1,179,736)
Capitalized salaries, general and administrative costs and interest, net of fees and reimbursements	44,282	45,757	36,178
Total additions (reductions) to oil and gas properties, net.....	<u>\$331,311</u>	<u>\$2,082,340</u>	<u>(\$1,143,558)</u>

(1) Includes asset retirement costs of \$11,607, (\$96,346) and \$20,171 for the years ended December 31, 2009, 2008 and 2007, respectively.

Production Volumes, Sales Price and Cost Data. The following table sets forth certain information regarding our production volumes, sales prices and average production costs for the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
Production:			
Oil (MBbls)	6,207	4,916	6,088
Natural gas (MMcf)	41,335	34,409	45,088
Oil and natural gas (MMcfe)	78,577	63,903	81,617
Average sales prices: (1)			
Oil (per Bbl)	\$70.72	\$93.79	\$69.68
Natural gas (per Mcf)	6.59	9.78	7.30
Oil and natural gas (per Mcfe)	9.05	12.48	9.23
Expenses (per Mcfe):			
Lease operating expenses (2)	\$2.00	\$2.68	\$1.83

(1) Includes the settlement of effective hedging contracts.

(2) Includes oil and gas operating costs and major maintenance expense and excludes production and ad valorem taxes.

Production Volumes, Sales Price and Cost Data for Individually Significant Fields. The following table sets forth certain information regarding our production volumes, sales prices and average production costs for the periods indicated for any field(s) containing 15% or more of our total estimated proved reserves at year-end.

Mississippi Canyon Block 109	Year Ended December 31,		
	2009	2008	2007
Production:			
Oil (MBbls)	861	1,035	1,756
Natural gas (MMcf)	1,092	1,700	2,234
Oil and natural gas (MMcfe)	6,256	7,913	12,767
Average sales prices: (1)			
Oil (per Bbl)	\$66.68	\$107.96	\$70.32
Natural gas (per Mcf)	3.81	9.55	6.71
Oil and natural gas (per Mcfe)	9.86	16.18	10.84
Expenses (per Mcfe):			
Lease operating expenses (2)	\$2.19	\$0.86	\$0.63

(1) Exclusive of the settlement of effective hedging contracts.

(2) Includes oil and gas operating costs and major maintenance expense and excludes production and ad valorem taxes.

Drilling Activity. The following table sets forth our drilling activity for the periods indicated.

	Year Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive.....	12.00	6.75	6.00	3.50	1.00	1.00
Dry.....	-	-	6.00	3.98	1.00	1.00
Development Wells:						
Productive.....	5.00	4.00	9.00	7.18	19.00	12.71
Dry.....	4.00	4.00	1.00	0.25	1.00	0.33

As of February 25, 2010, we have one well drilling in the GOM shelf. Our working interest in the well is 100%.

Productive Well and Acreage Data. The following table sets forth certain statistics regarding the number of productive wells and developed and undeveloped acreage as of December 31, 2009.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin.....	153	118
Rocky Mountain Region.....	-	-
Appalachia	-	-
	<u>153</u>	<u>118</u>
Gas (2):		
Gulf Coast Basin.....	93	73
Rocky Mountain Region.....	-	-
Appalachia.....	6	3
	<u>99</u>	<u>76</u>
Total	<u>252</u>	<u>194</u>
Developed Acres:		
Gulf Coast Basin.....	94,824	73,140
Rocky Mountain Region	40	14
Appalachia	525	263
	<u>95,389</u>	<u>73,417</u>
Undeveloped Acres (3):		
Gulf Coast Basin.....	512,019	364,314
Rocky Mountain Region	249,128	80,516
Appalachia	43,980	41,887
	<u>805,127</u>	<u>486,717</u>
Total	<u>900,516</u>	<u>560,134</u>

(1) 25 gross wells each have dual completions.

(2) 6 gross wells each have dual completions.

(3) Leases covering approximately 17.2% of our undeveloped gross acreage will expire in 2010, 10.6% in 2011, 8.4% in 2012, 31.2% in 2013, 4.7% in 2014, 7.0% in 2015, 6.0% in 2016, 1.7% in 2017, 9.3% in 2018 and 3.9% in 2019.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and gas industry. Before we commence drilling operations, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties.

ITEM 3. LEGAL PROCEEDINGS

Franchise Tax Action. On December 30, 2004, Stone was served with two petitions (civil action numbers 2004-6227 and 2004-6228) filed by the Louisiana Department of Revenue (“LDR”) in the 15th Judicial District Court (Parish of Lafayette, Louisiana) claiming additional franchise taxes due. In one case, the LDR is seeking additional franchise taxes from Stone in the amount of \$640,000, plus accrued interest of \$352,000 (calculated through December 15, 2004), for the franchise tax year 2001. In the other case, the LDR is seeking additional franchise taxes from Stone (as successor to Basin Exploration, Inc.) in the amount of \$274,000, plus accrued interest of \$159,000 (calculated through December 15, 2004), for the franchise tax years 1999, 2000 and 2001. On December 29, 2005, the LDR filed another petition in the 15th Judicial District Court claiming additional franchise taxes due for the taxable years ended December 31, 2002 and 2003 in the amount of \$2.6 million plus accrued interest calculated through December 15, 2005 in the amount of \$1.2 million. Also, on January 2, 2008, Stone was served with a petition (civil action number 2007-6754) claiming \$1.5 million of additional franchise taxes due for the 2004 franchise tax year, plus accrued interest of \$800,000 calculated through November 30, 2007. Further, on January 7, 2009, Stone was served with a petition (civil action number 2008-7193) claiming additional franchise taxes due for the taxable years ended December 31, 2005 and 2006 in the amount of \$4.0 million plus accrued interest calculated through October 21, 2008 in the amount of \$1.7 million. These assessments all relate to the LDR’s assertion that sales of crude oil and natural gas from properties located on the Outer Continental Shelf, which are transported through the State of Louisiana, should be sourced to the State of Louisiana for purposes of computing the Louisiana franchise tax apportionment ratio. The Company disagrees with these contentions and intends to vigorously defend itself against these claims. The franchise tax years 2007 through 2009 for Stone and franchise tax years 2006 through 2008 for Bois d’Arc remain subject to examination.

Federal Securities Action. On or around November 30, 2005, George Porch filed a putative class action in the United States District Court for the Western District of Louisiana (the “Federal Court”) against Stone, David Welch, Kenneth Beer, D. Peter Canty and James Prince purporting to allege violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934. Three similar complaints were filed soon thereafter. All complaints had asserted a putative class period commencing on June 17, 2005 and ending on October 6, 2005. All complaints contended that, during the putative class period, defendants, among other things, misstated or failed to disclose (i) that Stone had materially overstated Stone’s financial results by overvaluing its oil reserves through improper and aggressive reserve methodologies; (ii) that Stone lacked adequate internal controls and was therefore unable to ascertain its true financial condition; and (iii) that as a result of the foregoing, the values of Stone’s proved reserves, assets and future net cash flows were materially overstated at all relevant times. On March 17, 2006, these purported class actions were consolidated, with El Paso Fireman & Policeman’s Pension Fund designated as lead plaintiff (“Securities Action”). El Paso Fireman & Policeman’s Pension Fund filed a consolidated class action complaint on or about June 14, 2006. The consolidated complaint alleges claims similar to those described above and expands the putative class period to commence on May 2, 2001 and to end on March 10, 2006. On September 13, 2006, Stone and the individual defendants filed motions seeking dismissal of that action.

On August 17, 2007, a Federal Magistrate Judge issued a report and recommendation (the “Report”) recommending that the Federal Court grant in part and deny in part the Motions to Dismiss. The Report recommended that (i) the claims asserted against defendants Kenneth Beer and James Prince pursuant to Section 10(b) of the Securities Exchange Act and Rule 10b-5 promulgated thereunder and (ii) claims asserted on behalf of putative class members who sold their Company shares prior to October 6, 2005 be dismissed and that the Motions to Dismiss be denied with respect to the other claims against Stone and the individual defendants.

On October 1, 2007, the Federal Court issued an Order directing that judgment on the Motions to Dismiss be entered in accordance with the recommendations of the Report. On October 23, 2007, Stone and the individual defendants filed a motion seeking permission to appeal the denial of the Motions to Dismiss to the Fifth Circuit Court of Appeals, which motion was denied. The discovery process began, and the parties exchanged initial disclosures, document requests, and interrogatories and also began producing documents.

On or about May 12, 2008, El Paso Fireman & Policeman’s Pension Fund filed a motion to certify the Securities Action as a class action under Rule 23 of the Federal Rules of Civil Procedure (“Class Certification Motion”). Defendants filed their opposition to the Class Certification Motion on June 27, 2008. Defendants also filed a Motion for Judgment on the Pleadings and a related Motion to Amend Answer to the Consolidated Class Action Complaint on or about June 11, 2008. In a memorandum ruling filed on February 27, 2009, the Court dismissed El Paso Fireman & Policeman’s Pension Fund from the lawsuit, holding that El Paso Fireman & Policeman’s Pension Fund did not have capacity to sue or be sued, and subsequently, the Court denied the Class Certification Motion as moot.

On September 30, 2009, the City of Knoxville Employees’ Pension Board (“Knoxville”) was appointed as the new lead plaintiff. On October 30, 2009, Knoxville filed a new motion for class certification. On November 25, 2009, all parties advised the Court that they had reached a settlement in principle of all claims in the Securities Action. Because the Securities Action was brought as a putative class action, the proposed settlement is subject to Court approval under Rule 23 of the Federal Rules of Civil Procedure. Knoxville filed on January 11, 2010 a motion for preliminary approval of the settlement, which included as an exhibit a stipulation of settlement signed by counsel for all parties. The stipulation of settlement sets forth all material terms of the

settlement, including the settlement payment amount of \$10.5 million and the complete release of all claims against all defendants in the Securities Action. The settlement payment is being made under the Company's directors and officers liability insurance policy.

The Court issued an order on January 14, 2010 preliminarily approving the settlement (the "January 24, 2010 Order"). The Court has set a Settlement Fairness Hearing to be held on March 23, 2010 in Lafayette, Louisiana. The Court's January 14, 2010 Order sets forth the procedures that must be followed within 120 days of the notice of settlement (which occurred on or about January 22, 2010) by any shareholder that would like to be considered for a distribution of the \$10.5 million settlement payment. The January 14, 2010 Order also sets for the procedures for making objections to the proposed settlement and for seeking exclusion from (or "opting out" of) the binding settlement, both of which the Court has ordered must be done no later than fourteen (14) days before the Settlement Fairness Hearing.

Derivative Actions. In addition, on or about December 16, 2005, Robert Farer and Priscilla Fisk filed respective complaints in the Federal Court purportedly alleging claims derivatively on behalf of Stone. Similar complaints were filed thereafter in the Federal Court by Joint Pension Fund, Local No. 164, I.B.E.W., and in the 15th Judicial District Court, Parish of Lafayette, Louisiana (the "State Court") by Gregory Sakhno. Stone was named as a nominal defendant and David Welch, Kenneth Beer, D. Peter Canty, James Prince, James Stone, John Laborde, Peter Barker, George Christmas, Richard Pattarozzi, David Voelker, Raymond Gary, B.J. Duplantis and Robert Bernhard were named as defendants in these actions. (These actions are collectively referred to as the "Derivative Actions.") The State Court action purportedly alleged claims of breach of fiduciary duty, abuse of control, gross mismanagement, and waste of corporate assets against all defendants, and claims of unjust enrichment and insider selling against certain individual defendants. The Federal Court derivative actions asserted purported claims against all defendants for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets and unjust enrichment and claims against certain individual defendants for breach of fiduciary duty and violations of the Sarbanes-Oxley Act of 2002.

On March 30, 2006, the Federal Court entered an order consolidating the Federal Court derivative actions and naming Robert Farer, Priscilla Fisk and Joint Pension Fund, Local No. 164, I.B.E.W. as co-lead plaintiffs in the consolidated Federal Court derivative action. On December 21, 2006, the Federal Court stayed the Federal Court derivative action at least until resolution of the then-pending motion to dismiss the Securities Action after which time a hearing was to be conducted by the Federal Court to determine the propriety of maintaining that stay. As of the date hereof, the Federal Court has not been requested to consider any potential modification of the stay.

On February 16, 2010, a stipulation of settlement signed by counsel for all parties to the Derivative Action was filed with the Federal Court. The material terms of the settlement are set forth in detail in this stipulation. The terms include (i) a monetary payment of \$300,000 for attorneys' fees and expenses, and (ii) the continuation of certain corporate governance measures respecting (1) the procedures to be followed by the Company's Reserves Committee, (2) the maintenance of an anonymous reporting policy, and (3) the maintenance of an anonymous third party hotline. The Company anticipates that the \$300,000 payment will be made under the Company's directors and officers liability insurance policy. This proposed settlement is also subject to Federal Court approval under Rule 23.1 of the Federal Rules of Civil Procedure. On February 18, 2010, the Federal Court entered an order preliminarily approving this proposed settlement ("February 18, 2010 Order"). The February 18, 2010 Order set a Settlement Hearing for March 23, 2010 at 1:30 p.m. to consider the propriety of finally approving the proposed settlement and awarding attorneys' fees. The February 18, 2010 Order also sets forth the procedures and deadlines for any shareholder to object to the settlement, which must be done no later than ten (10) calendar days prior to the Settlement Hearing.

Ad Valorem Tax Suit. In August 2009, Gene P. Bonvillain, in his capacity as Assessor for the Parish of Terrebonne, State of Louisiana, filed civil action No. 90-03540 and other consolidated cases in the United States District Court for the Eastern District of Louisiana against approximately thirty oil and gas companies, including Stone, and their respective chief executive officers for allegedly unpaid ad valorem taxes. The amount alleged to be due by Stone for the years 1998 through 2008 is \$11.3 million. The defendants were subsequently served and have filed motions to dismiss this litigation pursuant to Rule 12(b)(6) of the Federal Rules of Civil Procedure. The Company believes that the assessor is in error in his allegations, and the Company intends to vigorously defend this action.

Stone's Certificate of Incorporation and/or its Restated Bylaws provide, to the extent permissible under the law of the State of Delaware (Stone's state of incorporation), for indemnification of and advancement of defense costs to Stone's current and former directors and officers for potential liabilities related to their service to Stone. Stone has purchased directors and officers insurance policies that, under certain circumstances, may provide coverage to Stone and/or its officers and directors for certain losses resulting from securities-related civil liabilities and/or the satisfaction of indemnification and advancement obligations owed to directors and officers. These insurance policies may not cover all costs and liabilities incurred by Stone and its current and former officers and directors in these regulatory and civil proceedings.

The foregoing pending actions are at an early stage and subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation and the regulatory proceedings. Accordingly, based on the current status of the litigation and inquiries, we cannot currently predict the manner and timing of the resolution of these matters and are unable to

estimate a range of possible losses or any minimum loss from such matters. Furthermore, to the extent that our insurance policies are ultimately available to cover any costs and/or liabilities resulting from these actions, they may not be sufficient to cover all costs and liabilities incurred by us and our current and former officers and directors in these regulatory and civil proceedings.

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

No matters were submitted for a vote of our stockholders during the fourth quarter of 2009.

ITEM 4A. EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth information regarding the names, ages (as of February 25, 2010) and positions held by each of our executive officers, followed by biographies describing the business experience of our executive officers for at least the past five years. Our executive officers serve at the discretion of the board of directors.

<u>Name</u>	<u>Age</u>	<u>Position</u>
David H. Welch	61	President, Chief Executive Officer and Director
Kenneth H. Beer	52	Senior Vice President and Chief Financial Officer
Andrew L. Gates, III.....	62	Senior Vice President, General Counsel and Secretary
E. J. Louviere.....	61	Senior Vice President – Land
J. Kent Pierret	54	Senior Vice President, Chief Accounting Officer and Treasurer
Richard L. Smith.....	51	Senior Vice President – Exploration and Business Development
Jerome F. Wenzel, Jr.	57	Senior Vice President – Operations/Exploitation
Florence M. Ziegler	49	Vice President – Human Resources and Administration

David H. Welch was appointed President, Chief Executive Officer and a director of the Company effective April 1, 2004. Prior to joining Stone, Mr. Welch served as Senior Vice President of BP America, Inc. since 2003, and Vice President of BP, Inc. since 1999.

Kenneth H. Beer was named Senior Vice President and Chief Financial Officer in August 2005. He previously served as a director of research and a senior energy analyst at the investment banking firm of Johnson Rice & Company. Prior to joining Johnson Rice in 1992, he was an energy analyst and investment banker at Howard Weil Incorporated.

Andrew L. Gates, III was named Senior Vice President, General Counsel and Secretary in April 2004. He previously served as Vice President, General Counsel and Secretary since August 1995.

E. J. Louviere was named Senior Vice President – Land in April 2004. Previously, he served as Vice President – Land since June 1995. He has been employed by Stone since its inception in 1993.

J. Kent Pierret was named Senior Vice President – Chief Accounting Officer and Treasurer in April 2004. Mr. Pierret previously served as Vice President and Chief Accounting Officer since June 1999 and Treasurer since February 2004.

Richard L. Smith was appointed Vice President – Exploration and Business Development in June 2007 and was named Senior Vice President – Exploration and Business Development in January 2009. Prior to joining Stone, Mr. Smith served as the General Manager of Deepwater Gulf of Mexico Exploration of Dominion E&P Inc. from 2003 to 2007. Mr. Smith has also worked for Exxon Corporation and Texaco USA with experience in deep water, shelf, onshore, and international projects.

Jerome F. Wenzel, Jr. joined Stone in October 2004 as Vice President-Production and Drilling and was named Senior Vice President – Operations/Exploitation in September 2005. Prior to joining Stone, Mr. Wenzel held managerial and executive positions with Amoco and BP America, Inc. over a 29 year career.

Florence M. Ziegler was named Vice President – Human Resources and Administration in September 2005. She has been employed by Stone since its inception in 1993 and served as the Director of Human Resources from 1997 to 2004.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Since July 9, 1993, our common stock has been listed on the New York Stock Exchange under the symbol “SGY.” The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock.

	High	Low
<u>2008</u>		
First Quarter.....	\$55.89	\$39.14
Second Quarter	73.96	52.20
Third Quarter	68.14	37.86
Fourth Quarter	41.61	8.47
<u>2009</u>		
First Quarter.....	\$13.73	\$1.55
Second Quarter	9.85	3.09
Third Quarter	18.43	5.83
Fourth Quarter	20.51	13.75
<u>2010</u>		
First Quarter (through February 22, 2010)	\$19.76	\$14.12

On February 22, 2010, the last reported sales price on the New York Stock Exchange Composite Tape was \$16.80 per share. As of that date, there were 296 holders of record of our common stock.

Dividend Restrictions

In the past, we have not paid cash dividends on our common stock, and we do not intend to pay cash dividends on our common stock in the foreseeable future. We currently intend to retain earnings, if any, for the future operation and development of our business. The restrictions on our present or future ability to pay dividends are included in the provisions of the Delaware General Corporation Law and in certain restrictive provisions in the indentures executed in connection with our 6-3/4% Senior Subordinated Notes due 2014 and our 8.625% Senior Notes due 2017. In addition, our bank credit facility contains provisions that may have the effect of limiting or prohibiting the payment of dividends.

Issuer Purchases of Equity Securities

On September 24, 2007, our Board of Directors authorized a share repurchase program for an aggregate amount of up to \$100 million. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. Additionally, shares were withheld from certain employees to pay taxes associated with the employees’ vesting of restricted stock. The following table sets forth information regarding our repurchases or acquisitions of common stock during the fourth quarter of 2009:

Period	Total Number of Shares (or Units) Purchased	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet be Purchased Under the Plans or Programs
Share Repurchase Program:				
October 2009	-	-	-	
November 2009	-	-	-	
December 2009	-	-	-	
	-	-	-	\$92,928,632
Other:				
October 2009	5,953 (a)	\$15.58	-	
November 2009	-	-	-	
December 2009	63 (a)	19.20	-	
	6,016	15.92	-	N/A
Total	6,016	\$15.92	-	

(a) Amounts represent shares withheld from employees upon the vesting of restricted stock in order to satisfy the required tax withholding obligations.

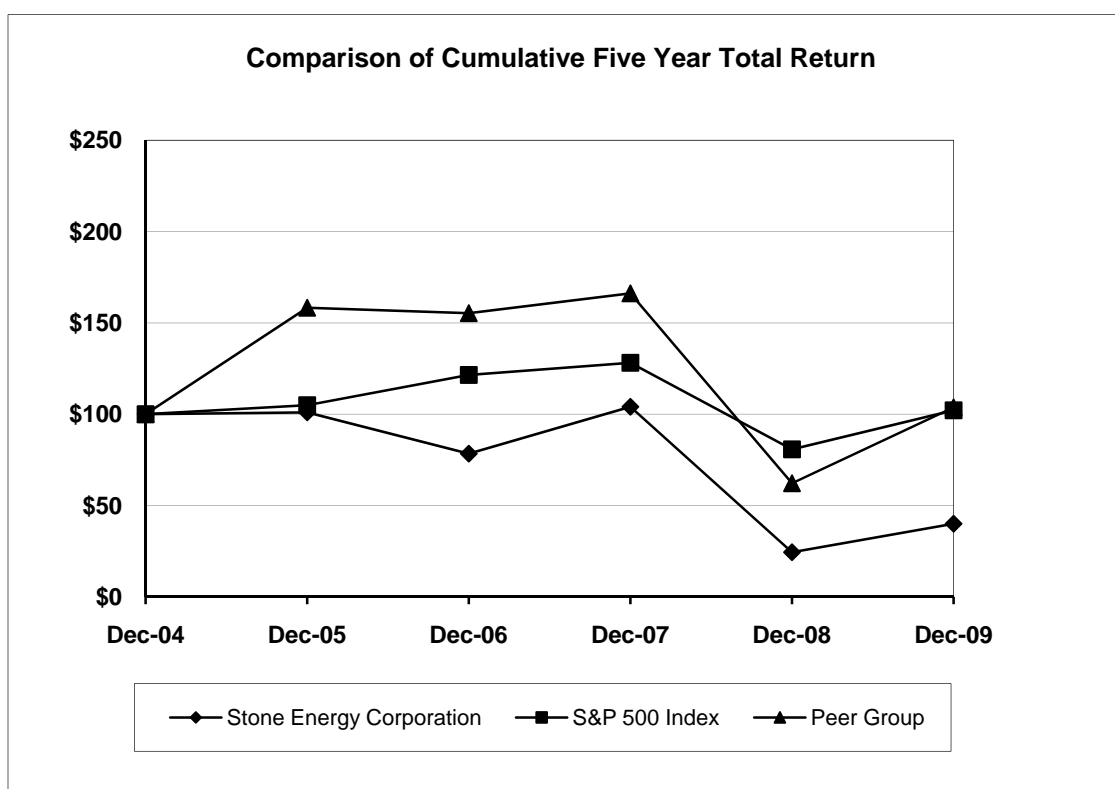
Equity Compensation Plan Information

Please refer to Item 12 of this Annual Report on Form 10-K for information concerning securities authorized under our equity compensation plan.

Stock Performance Graph

As required by applicable rules of the SEC, the performance graph shown below was prepared based upon the following assumptions:

1. \$100 was invested in the Company's Common Stock, the S&P 500 Index and the Peer Group (as defined below) on December 31, 2004 at \$45.09 per share for the Company's Common Stock and at the closing price of the stocks comprising the S&P 500 Index and the Peer Group, respectively, on such date.
2. Peer Group investment is weighted based upon the market capitalization of each individual company within the Peer Group at the beginning of the period.
3. Dividends are reinvested on the ex-dividend dates.



Measurement Period (Fiscal Year Covered)	SGY	Peer Group	S&P 500 Index
12/31/05	100.98	158.32	104.91
12/31/06	78.40	155.34	121.48
12/31/07	104.04	166.16	128.16
12/31/08	24.44	62.24	80.74
12/31/09	40.03	103.72	102.11

The companies that comprised our Peer Group in 2009 were: ATP Oil & Gas Corporation, Callon Petroleum Company, Energy Partners, Ltd., Energy XXI (Bermuda) Limited, Mariner Energy Inc., McMoRan Exploration Company, Newfield Exploration Company, PetroQuest Energy, Inc., Swift Energy Company, and W&T Offshore, Inc.

The information in this Form 10-K appearing under the heading "Stock Performance Graph" is being "furnished" pursuant to Item 2.01(e) of Regulation S-K under the Securities Act of 1933, as amended, and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Securities Exchange Act of 1934, as amended.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2009. This information is derived from our Consolidated Financial Statements and the notes thereto. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8. Financial Statements and Supplementary Data.”

	Year Ended December 31,				
	2009	2008	2007	2006	2005
(In thousands, except per share amounts)					
Statement of Operations Data:					
Operating revenue:					
Oil production	\$438,942	\$461,050	\$424,205	\$348,979	\$244,469
Gas production	272,353	336,665	329,047	337,321	391,771
Derivative income, net.....	<u>3,061</u>	<u>3,327</u>	-	<u>2,688</u>	-
Total operating revenue	<u>714,356</u>	<u>801,042</u>	<u>753,252</u>	<u>688,988</u>	<u>636,240</u>
Operating expenses:					
Lease operating expenses	156,786	171,107	149,702	159,043	114,664
Other operational expense	2,400	-	-	-	-
Production taxes	7,920	7,990	9,945	13,472	13,179
Depreciation, depletion and amortization.....	259,639	288,384	302,739	320,696	241,426
Write-down of oil and gas properties	505,140	1,309,403	8,164	510,013	-
Goodwill impairment	-	465,985	-	-	-
Accretion expense	33,016	17,392	17,620	12,391	7,159
Salaries, general and administrative expenses.....	41,367	43,504	33,584	34,266	22,705
Incentive compensation expense	6,402	2,315	5,117	4,356	1,252
Impairment of inventory.....	9,398	-	-	-	-
Derivative expenses, net.....	-	-	666	-	3,388
Total operating expenses.....	<u>1,022,068</u>	<u>2,306,080</u>	<u>527,537</u>	<u>1,054,237</u>	<u>403,773</u>
Gain on Rocky Mountain Region properties divestiture.....	-	-	59,825	-	-
Income (loss) from operations	<u>(307,712)</u>	<u>(1,505,038)</u>	<u>285,540</u>	<u>(365,249)</u>	<u>232,467</u>
Other (income) expenses:					
Interest expense	21,361	13,243	32,068	35,931	23,151
Interest income	(528)	(11,250)	(12,135)	(2,524)	(1,095)
Other income, net	(3,854)	(5,800)	(5,657)	(4,657)	(2,799)
Merger expense reimbursement.....	-	-	-	(51,500)	-
Merger expenses.....	-	-	-	50,029	-
Early extinguishment of debt.....	-	-	844	-	-
Total other (income) expenses, net	<u>16,979</u>	<u>(3,807)</u>	<u>15,120</u>	<u>27,279</u>	<u>19,257</u>
Net income (loss) before income taxes	(324,691)	(1,501,231)	270,420	(392,528)	213,210
Income tax provision (benefit).....	<u>(113,010)</u>	<u>(363,923)</u>	<u>88,984</u>	<u>(138,306)</u>	<u>76,446</u>
Net income (loss).....	(211,681)	(1,137,308)	181,436	(254,222)	136,764
Net income (loss) attributable to non-controlling interest...	27	(77)	-	-	-
Net income (loss) attributable to Stone Energy Corp.....	<u>(\$211,708)</u>	<u>(\$1,137,231)</u>	<u>\$181,436</u>	<u>(\$254,222)</u>	<u>\$136,764</u>
Earnings and dividends per common share:					
Basic earnings (loss) per share.....	<u>(\$4.82)</u>	<u>(\$35.58)</u>	<u>\$6.50</u>	<u>(\$9.29)</u>	<u>\$5.01</u>
Diluted earnings (loss) per share.....	<u>(\$4.82)</u>	<u>(\$35.58)</u>	<u>\$6.49</u>	<u>(\$9.29)</u>	<u>\$5.01</u>
Cash dividends declared	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities	\$507,787	\$522,478	\$465,158	\$399,035	\$461,213
Net cash provided by (used in) investing activities.....	(316,079)	(1,357,907)	344,812	(660,456)	(499,932)
Net cash provided by (used in) financing activities	(190,552)	428,440	(393,706)	240,575	94,170
Balance Sheet Data (at end of period):					
Working capital	\$26,137	\$123,339	\$412,445	\$1,845	\$16,506
Oil and gas properties, net	1,185,709	1,624,321	1,181,312	1,784,425	1,810,959
Total assets	1,454,242	2,106,003	1,889,603	2,128,471	2,140,317
Long-term debt, less current portion	575,000	825,000	400,000	797,000	563,000
Stone Energy Corp. stockholders' equity	341,950	587,092	885,802	711,640	944,123

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

The following discussion is intended to assist in understanding our financial position and results of operations for each of the years in the three-year period ended December 31, 2009. Our Consolidated Financial Statements and the notes thereto, which are found elsewhere in this Form 10-K, contain detailed information that should be referred to in conjunction with the following discussion. See “**Item 1A. Risk Factors**” and “**Item 8. Financial Statements and Supplementary Data – Note 1.**”

Executive Overview

We are an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties located primarily in the Gulf of Mexico (“GOM”). We have been operating in the Gulf Coast Basin since our incorporation in 1993 and have established a technical and operational expertise in this area. More recently, we have made strategic investments in the deep water and deep shelf GOM, which we have targeted as important exploration areas. We are also active in the Appalachia region, where we have established a significant acreage position in the Marcellus Shale. On August 28, 2008, we completed the acquisition of Bois d’Arc Energy, Inc. (“Bois d’Arc”) in a cash and stock transaction totaling approximately \$1.7 billion. Bois d’Arc was an independent exploration company engaged in the discovery and production of oil and natural gas in the GOM. See “**Item 1. Business – Strategy and Operational Overview.**”

2009 Significant Events.

- *Unwinding of 2009 Hedge Positions* - In March 2009, we unwound all of our then existing crude oil hedges for the period from April 2009 through December 2009 and two of our natural gas hedges for the period from April 2009 through December 2009, resulting in proceeds of approximately \$113 million. These contracts were unwound to provide a source of liquidity to assist with funding capital expenditures, which were heavily weighted toward the first two quarters of the year.
- *Declining Commodity Prices* - During the first quarter of 2009, we experienced declines in oil and natural gas prices which contributed to ceiling test write-downs during the year.
- *Public Offering of Common Stock* - In June 2009, we sold 8,050,000 shares of our common stock in a public offering at a price of \$8.00 per share resulting in net proceeds of approximately \$60.4 million after deducting underwriters’ discounts and offering expenses. The net proceeds were used for general corporate purposes, including the reduction of outstanding bank debt.
- *Pyrenees Discovery* - In June 2009, we announced a discovery on our deepwater Pyrenees Prospect, located on Garden Banks Block 293. The well encountered approximately 125 feet of net hydrocarbon pay in three zones. We have a 15% working interest in the prospect and a small overriding royalty. Delineation drilling on the Pyrenees Discovery is now complete and has provided the necessary information to appraise the three pay zones discovered in the initial well. This represents our first deep water discovery.
- *Bank Credit Facility Borrowing Base Redetermination* – On April 29, 2009, our borrowing base was reduced from \$625 million to \$425 million. On October 9, 2009, the semi-annual redetermination process was completed and our borrowing base was reaffirmed at \$425 million. On January 26, 2010, we completed a public offering of \$275 million aggregate principal amount of 8.625% Senior Notes due 2017. In connection with this offering, we entered into an amendment to our bank credit facility, under which our borrowing base was automatically reduced from \$425 million to \$395 million. See “ - *Bank Credit Facility*” below for additional information regarding our senior secured bank credit facility.

2010 Outlook.

Our 2010 capital expenditure budget is approximately \$400 million. This figure compares with a \$300 million capital budget for 2009 and excludes material acquisitions and capitalized salaries, general and administrative expenses and interest. Approximately 25% of the capital expenditure budget is expected to be spent on Appalachian drilling and acreage acquisition; approximately 25% is planned for GOM shelf exploitation; approximately 15% is for GOM workover/recompletion projects; approximately 15% is scheduled for GOM deep water and deep shelf expenditures; and the remaining budget is for facilities, abandonment projects, and miscellaneous exploration projects.

On January 26, 2010, we completed a public offering of \$275 million aggregate principal amount of 8.625% Senior Notes due 2017. The net proceeds from the offering after deducting underwriting discounts, commissions, estimated fees and expenses totaled \$265 million. Approximately \$202 million of the net proceeds from the offering were used to fund the tender offer and

consent solicitation and redemption of our outstanding 8¼% Senior Subordinated Notes due 2011. The remaining proceeds are being used for general corporate purposes, including the repayment of borrowings under our bank credit facility.

Known Trends and Uncertainties.

Hurricanes – Since the majority of our production originates in the GOM, we are particularly vulnerable to the effects of hurricanes on production. Additionally, affordable insurance coverage for property damage to our facilities for hurricanes is becoming more difficult to obtain. We have narrowed our insurance coverage to selected properties, increased our deductibles and are shouldering more hurricane related risk in the environment of rising insurance rates.

Reserve Replacement – We have faced challenges in replacing production at a reasonable unit cost. Our diversification into the deep water/deep shelf GOM and Appalachia are strategies we are employing to mitigate this trend.

Louisiana Franchise Taxes – We have been involved in litigation with the state of Louisiana over the proper computation of franchise taxes allocable to the state. This litigation relates to the state's position that sales of crude oil and natural gas from properties located on the Outer Continental Shelf, which are transported through the state of Louisiana, should be sourced to Louisiana for purposes of computing franchise taxes. We disagree with the state's position. However, if the state's position were to be upheld, we could incur additional expense for alleged underpaid franchise taxes in prior years and higher franchise tax expense in future years. See **"Item 3. Legal Proceedings."** As of December 31, 2009, the state of Louisiana had asserted claims of additional franchise taxes in the amount of \$9.0 million plus accrued interest of \$4.2 million. There are open franchise tax years which the state has not yet audited which expose us to estimated additional assessments of \$8.1 million plus interest of \$4.6 million.

Liquidity and Capital Resources

At February 23, 2010, we had \$206.9 million of availability under our bank credit facility and cash on hand of approximately \$90.7 million. Our capital expenditure budget for 2010 has been set at \$400 million, which we intend to finance primarily with cash flow from operations. If we do not have sufficient cash flow from operations or availability under our bank credit facility, we may be forced to reduce our capital expenditures. To the extent that 2010 cash flow from operations exceeds our estimated 2010 capital expenditures, we may pay down a portion of our existing debt, expand our capital budget, or invest in the money markets.

We do not budget acquisitions; however, we are continually evaluating opportunities that fit our specific acquisition profile. See **"Item 1. Business – Strategy and Operational Overview."** Any one or a combination of certain of these possible transactions could fully utilize our existing sources of capital. Although we have no current plans to access the public markets for purposes of capital, if the opportunity arose, we would consider such funding sources to provide capital in excess of what is currently available to us.

Cash Flow and Working Capital. Net cash flow provided by operating activities totaled \$507.8 million during 2009 compared to \$522.5 million and \$465.2 million in 2008 and 2007, respectively. Based on our outlook of commodity prices and our estimated production, we expect to fund our 2010 capital expenditures with cash flow provided by operating activities.

Net cash flow used in investing activities totaled \$316.1 million during 2009, which primarily represents our investment in oil and natural gas properties. Net cash flow used in investing activities totaled \$1.4 billion during the year ended December 31, 2008, which primarily represents cash used in connection with the acquisition of Bois d'Arc and our investment in oil and natural gas properties. Net cash flow provided by investing activities totaled \$344.8 million during the year ended December 31, 2007, which primarily represents proceeds received from the sale of substantially all of our Rocky Mountain Region properties partially offset by our investment in oil and natural gas properties.

Net cash flow used in financing activities totaled \$190.6 million for the year ended December 31, 2009, which primarily represents repayments of borrowings under our bank credit facility of \$250 million partially offset by proceeds from the sale of common stock of approximately \$60.4 million. Net cash flow provided by financing activities totaled \$428.4 million during the year ended December 31, 2008, which primarily represents borrowings under our bank credit facility in conjunction with our acquisition of Bois d'Arc and proceeds from the exercise of stock options and vesting of restricted stock. Net cash flow used in financing activities totaled \$393.7 million during the year ended December 31, 2007, which primarily represents the redemption of our Senior Floating Rate Notes due 2010 and repayments of borrowings under our bank credit facility.

We had working capital at December 31, 2009 of \$26.1 million.

Capital Expenditures. In 2009, additions to oil and gas property costs of \$331.3 million included \$9.1 million of lease acquisition costs, \$18.7 million of capitalized salaries, general and administrative expenses (inclusive of incentive compensation) and \$25.6 million of capitalized interest. These investments were financed by cash flow from operations.

Bank Credit Facility. On August 28, 2008, we entered into an amended and restated revolving credit facility totaling \$700 million, maturing on July 1, 2011, with a syndicated bank group. At December 31, 2008, our bank credit facility had a borrowing base of \$625 million. On April 28, 2009, the credit facility was amended, and on April 29, 2009, the borrowing base was reduced to \$425 million. On October 9, 2009, the borrowing base was reaffirmed at \$425 million at the semi-annual redetermination. At December 31, 2009, we had \$175 million of outstanding borrowings under our bank credit facility, letters of credit totaling \$63.1 million had been issued under the facility, and the weighted average interest rate was 2.7%. On January 26, 2010, we completed a public offering of \$275 million aggregate principal amount of 8.625% Senior Notes due 2017. In connection with this offering, we entered into an amendment to our bank credit facility, which provided that if we issued more than \$200 million of notes, the borrowing base under our bank credit facility would automatically be reduced by an amount equal to 40% of the amount in excess of \$200 million. Upon completion of the offering, our borrowing base was automatically reduced from \$425 million to \$395 million. As of February 25, 2010, we had \$125 million of outstanding borrowings under our bank credit facility and \$63.1 million in letters of credit had been issued pursuant to the facility, leaving \$206.9 million of availability under the facility. The facility is guaranteed by all of our material direct and indirect subsidiaries, including Stone Energy Offshore, L.L.C. (“Stone Offshore”), a wholly owned subsidiary of Stone.

The borrowing base under our bank credit facility is redetermined semi-annually, in May and November, by the lenders taking into consideration the estimated value of our oil and gas properties and those of our direct and indirect material subsidiaries in accordance with the lenders’ customary practices for oil and gas loans. In addition, we and the lenders each have discretion at any time, but not more than two additional times in any calendar year, to have the borrowing base redetermined. Our bank credit facility is collateralized by substantially all of Stone’s and Stone Offshore’s assets. Stone and Stone Offshore are required to mortgage, and grant a security interest in, their oil and gas reserves representing at least 80% of the discounted present value of the future net cash flows from their oil and gas reserves reviewed in determining the borrowing base. At Stone’s option, loans under the credit facility will bear interest at a rate based on the adjusted LIBOR plus an applicable margin, or a rate based on the prime rate or Federal funds rate plus an applicable margin.

Under the financial covenants of our credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a ratio of EBITDA to consolidated Net Interest, as defined in the credit agreement, for the preceding four quarterly periods of not less than 3.0 to 1.0. As of December 31, 2009 our debt to EBITDA Ratio was 1.14 to 1 and our EBITDA to consolidated Net Interest Ratio was approximately 24.18 to 1. In addition, the credit facility includes certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends but do allow for limited stock repurchases.

Senior Notes Offering and Redemption of Senior Subordinated Notes. On January 26, 2010, we completed a public offering of \$275 million aggregate principal amount of 8.625% Senior Notes due 2017. The net proceeds from the offering after deducting underwriting discounts, commissions, estimated fees and expenses totaled \$265 million. Approximately \$202 million of the net proceeds from the offering were used to fund the tender offer and consent solicitation and redemption of our outstanding 8¼% Senior Subordinated Notes due 2011. The remaining proceeds are being used for general corporate purposes, including the repayment of borrowings under our bank credit facility.

Share Repurchase Program. On September 24, 2007, our Board of Directors authorized a share repurchase program for an aggregate amount of up to \$100 million. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. Through December 31, 2009, 300,000 shares had been repurchased under this program at a total cost of \$7.1 million.

Hedging. See “**Item 7A. Quantitative and Qualitative Disclosure About Market Risk – Commodity Price Risk.**”

Contractual Obligations and Other Commitments

The following table summarizes our significant contractual obligations and commitments, other than hedging contracts, by maturity as of December 31, 2009 (in thousands):

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Contractual Obligations and Commitments:					
8¼% Senior Subordinated Notes due 2011 (1).....	\$200,000	\$ -	\$200,000	\$ -	\$ -
6¾% Senior Subordinated Notes due 2014	200,000	-	-	200,000	-
Bank credit facility (2).....	175,000	-	175,000	-	-
Interest and commitment fees (3)	108,074	35,791	45,875	26,408	-
Asset retirement obligations including accretion...	588,233	32,000	71,366	112,611	372,256
Rig commitments	18,905	18,905	-	-	-
Seismic data commitments (4)	9,651	9,651	-	-	-
Operating lease obligations	725	473	193	59	-
Total Contractual Obligations and Commitments.....	\$1,300,588	\$96,820	\$492,434	\$339,078	\$372,256

- (1) The 8¼% Senior Subordinated Notes due 2011 were purchased pursuant to a tender offer and consent solicitation and redemption in January and February, 2010. On January 26, 2010, we issued \$275,000 aggregate principal amount of 8.625% Senior Notes due 2017.
- (2) The bank credit facility matures on July 1, 2011. See “**Liquidity and Capital Resources - Bank Credit Facility**” above.
- (3) Assumes 2.73% interest rate on the bank credit facility and 0.5% fee on unused commitments. See “**Liquidity and Capital Resources - Bank Credit Facility**” above.
- (4) Represents pre-commitments for seismic data purchases.

Results of Operations

2009 Compared to 2008. The following table sets forth certain operating information with respect to our oil and gas operations and summary information with respect to our estimated proved oil and gas reserves. See “**Item 2. Properties – Oil and Natural Gas Reserves.**”

	Year Ended December 31,			
	2009	2008	Variance	% Change
Production:				
Oil (MBbls).....	6,207	4,916	1,291	26%
Natural gas (MMcf)	41,335	34,409	6,926	20%
Oil and natural gas (MMcfe)	78,577	63,903	14,674	23%
Average prices: (1)				
Oil (per Bbl).....	\$70.72	\$93.79	(\$23.07)	(25%)
Natural gas (per Mcf)	6.59	9.78	(3.19)	(33%)
Oil and natural gas (per Mcfe)	9.05	12.48	(3.43)	(27%)
Expenses (per Mcfe):				
Lease operating expenses	\$2.00	\$2.68	(\$0.68)	(25%)
Salaries, general and administrative expenses (2) ..	0.53	0.68	(0.15)	(22%)
DD&A expense on oil and gas properties.....	3.23	4.45	(1.22)	(27%)
Estimated Proved Reserves at December 31:				
Oil (MBbls).....	32,336	36,564	(4,228)	(12%)
Natural gas (MMcf).....	216,694	299,554	(82,860)	(28%)
Oil and natural gas (MMcfe)	410,711	518,935	(108,224)	(21%)

- (1) Includes the settlement of effective hedging contracts.
- (2) Exclusive of incentive compensation expense.

For the year ended 2009, we reported a net loss totaling \$211.7 million, or \$4.82 per share, compared to a net loss for the year ended December 31, 2008 of \$1,137.2 million, or \$35.58 per share. All per share amounts are on a diluted basis. On August 28, 2008, we completed our acquisition of Bois d’Arc. The revenues and expenses associated with Bois d’Arc have been included in Stone’s consolidated financial statements since August 28, 2008.

We follow the full cost method of accounting for oil and gas properties. At March 31, 2009 and December 31, 2009, we recognized ceiling test write-downs of our oil and gas properties (United States) totaling \$505.1 million (\$328.3 million after

taxes). At the end of 2008, we recognized a ceiling test write-down of our oil and gas properties (United States and China) totaling \$1,309.4 million (\$851.1 million after taxes). The write-downs did not impact our cash flow from operations but did reduce net income and stockholders' equity. At December 31, 2008, approximately \$157.8 million of unevaluated costs were determined to be impaired and were reclassified to proved oil and gas properties and included in our ceiling test computation.

The 2008 net loss includes a goodwill impairment charge totaling \$466.0 million (no tax effect). The goodwill impairment charge did not impact our cash flow from operations but did reduce net income and stockholders' equity. The goodwill related to our acquisition of Bois d'Arc.

The variance in annual results was also due to the following components:

Production. Production volumes during 2009 totaled 6,207,000 barrels of oil and 41.3 Bcf of natural gas compared to 4,916,000 barrels of oil and 34.4 Bcf of natural gas produced during 2008, an increase on a gas equivalent basis of 14.7 Bcfe. Production rates were negatively impacted by Gulf Coast shut-ins due to Hurricanes Gustav and Ike during 2009 and 2008, amounting to volumes of approximately 11.8 Bcfe and 18.1 Bcfe, respectively. Without the effects of the hurricane production deferrals, year to year total production volumes increased approximately 8.4 Bcfe, primarily the result of a full year of production associated with the Bois d'Arc properties in 2009.

Prices. Prices realized during 2009 averaged \$70.72 per barrel of oil and \$6.59 per Mcf of natural gas, or 27% lower, on an Mcfe basis, than 2008 average realized prices of \$93.79 per barrel of oil and \$9.78 per Mcf of natural gas. All unit pricing amounts include the settlement of effective hedging contracts.

We enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During the years ended December 31, 2009 and 2008, our effective hedging transactions increased our average realized natural gas price by \$2.45 per Mcf and \$0.44 per Mcf, respectively. During the year ended December 31, 2009, our effective hedging transactions increased our average realized oil price by \$9.95 per barrel. Average realized oil prices were decreased during the year ended December 31, 2008 by \$7.01 per barrel as a result of effective hedging transactions.

Income. Oil and natural gas revenue decreased 11% to \$711.3 million in 2009 from \$797.7 million during 2008. The decrease was due to a 27% decrease in average realized prices on a gas equivalent basis, partially offset by oil and natural gas revenue associated with the Bois d'Arc properties totaling \$169.8 million for the full year of 2009. Oil and natural gas revenue related to the properties acquired from Bois d'Arc totaled \$47.3 million from August 28, 2008 through December 31, 2008.

Interest income totaled \$0.5 million during the year ended December 31, 2009 compared to \$11.3 million during the year ended December 31, 2008. The decrease in interest income is the result of lower interest rates and a decrease in our cash balances during the periods after the acquisition of Bois d'Arc.

Derivative Income/Expense. During 2009, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. Net derivative income for the year ended December 31, 2009, totaled \$3.1 million, consisting of \$8.2 million of cash settlements on the ineffective portion of derivative contracts, less \$5.1 million of changes in the fair market value of the ineffective portion of derivative contracts. During 2008, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. During the second half of 2008, as a result of extended shut-ins of production after Hurricanes Gustav and Ike, our September 2008 crude oil and natural gas production levels were below the volumes that we had hedged. Consequently, some of our crude oil and natural gas hedges for September 2008 were deemed to be ineffective. Net derivative income for the year ended December 31, 2008, totaled \$3.3 million, consisting of \$0.7 million of cash settlements on the ineffective derivative contracts, \$4.5 million of changes in the fair market value of the ineffective portion of derivative contracts, less \$1.9 million of amortization of the cost of puts.

Expenses. Lease operating expenses for the year ended December 31, 2009 totaled \$156.8 million, compared to \$171.1 million incurred during 2008. The decrease in lease operating expenses was the result of a decline in major maintenance expenses. Partially offsetting the decrease are lease operating expenses from the Bois d'Arc properties for a full year in 2009 compared to a partial year in 2008. Included in lease operating expenses from August 28, 2008 through December 31, 2008 are \$28.6 million of expenses for the properties acquired from Bois d'Arc. For the year ended December 31, 2009, lease operating expenses for the properties acquired from Bois d'Arc totaled \$62.5 million.

The other operational expense charge of \$2.4 million for the year ended December 31, 2009 related to the cancellation of a drilling contract.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2009 totaled \$253.8 million, or \$3.23 per Mcfe, compared to DD&A expense of \$284.7 million, or \$4.45 per Mcfe in the year ended

December 31, 2008. The overall decrease in DD&A from 2008 was primarily due to the 2008 year-end and first quarter 2009 ceiling test write-downs, which reduced the carrying value of the full cost pool for our oil and gas properties.

For the years ended December 31, 2009 and 2008, accretion expense totaled \$33.0 million and \$17.4 million, respectively. Due to falling commodity prices and hurricanes, the timing on a substantial portion of our asset retirement obligations was revised in the fourth quarter of 2008 leading to a redetermination of the present value of these obligations. In this redetermination, our credit adjusted risk free interest rate was increased to account for current credit conditions, resulting in a material increase in accretion expense in 2009. Also contributing to the increase was the addition of liabilities associated with properties acquired from Bois d'Arc.

During 2009 and 2008, salaries, general and administrative ("SG&A") expenses (exclusive of incentive compensation) totaled \$41.4 million and \$43.5 million, respectively.

For the years ended December 31, 2009 and 2008, incentive compensation expense totaled \$6.4 million and \$2.3 million, respectively. These amounts related to incentive compensation bonuses calculated based on the achievement of certain strategic objectives for each year.

The impairment of inventory for 2009 totaling \$9.4 million related to the write-down of our tubular inventory. This charge was the result of the market value of these tubular goods falling below historical cost. We consider only tubular goods not committed to capital projects to be inventory items.

Interest expense for 2009 totaled \$21.4 million, net of \$25.6 million of capitalized interest, compared to interest of \$13.2 million, net of \$26.4 million of capitalized interest, during 2008. The increase in interest expense in 2009 was primarily the result of interest expense associated with an increase in outstanding borrowings under our bank credit facility in the first half of 2009.

We estimate that we have incurred \$30.4 million of current federal income tax expense for calendar year 2009. This was largely due to a reclassification between current and deferred income tax expense related to a proposed IRS audit adjustment with respect to the timing of certain deductions. We had an \$11.1 million current income tax payable at December 31, 2009.

Asset Retirement Obligations. Primarily due to changes in estimated reserve lives, the timing on a substantial portion of our asset retirement obligations was revised in the fourth quarter of 2009 leading to a redetermination of the present value of these obligations. In this redetermination, our credit adjusted risk free rate was decreased to account for current credit conditions contributing to a significant upward revision of our asset retirement obligations of \$76.4 million.

Reserves. At December 31, 2009, our estimated proved oil and gas reserves totaled 410.7 Bcfe, compared to December 31, 2008 reserves of 518.9 Bcfe. Estimated proved natural gas reserves totaled 216.7 Bcf and estimated proved oil reserves totaled 32.3 MMBbls at the end of 2009. The decline in estimated proved reserves from year-end 2008 was due to production, negative commodity pricing revisions and other revisions to comply with the new SEC rules regarding oil and gas reserve estimation. The reserve estimates at December 31, 2009 were prepared by Netherland, Sewell & Associates, Inc. in accordance with guidelines established by the Securities and Exchange Commission ("SEC").

Our standardized measure of discounted future net cash flows was \$615.0 million at December 31, 2009. As required by the SEC, at December 31, 2009, we determined this estimate of future net cash flows using a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month of our fiscal year. The 12-month average oil and gas prices net of differentials on all of our properties used in determining this amount, excluding the effects of hedges in place at year-end, were \$58.95 per barrel and \$3.49 per Mcf for 2009. Our standardized measure of discounted future net cash flows was \$793.1 million at December 31, 2008 using a single-day, period-end price as required under the old SEC guidelines. Prior to the issuance of the SEC's new rule, "Modernization of Oil and Gas Reporting", estimates of future net cash flows were based on market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices net of differentials on all of our properties used in determining our standardized measure of discounted future net cash flows at December 31, 2008, excluding the effects of hedges in place at year-end, were \$39.70 per barrel and \$5.87 per Mcf for 2008. You should not assume that these estimates of future net cash flows represent the fair value of our estimated oil and natural gas reserves.

2008 Compared to 2007. The following table sets forth certain operating information with respect to our oil and gas operations and summary information with respect to our estimated proved oil and gas reserves. See "**Item 2. Properties – Oil and Natural Gas Reserves.**"

	Year Ended December 31,			
	2008	2007	Variance	% Change
Production:				
Oil (MBbls).....	4,916	6,088	(1,172)	(19%)
Natural gas (MMcf)	34,409	45,088	(10,679)	(24%)
Oil and natural gas (MMcfe)	63,903	81,617	(17,714)	(22%)
Average prices: (1)				
Oil (per Bbl).....	\$93.79	\$69.68	\$24.11	35%
Natural gas (per Mcf)	9.78	7.30	2.48	34%
Oil and natural gas (per Mcfe)	12.48	9.23	3.25	35%
Expenses (per Mcfe):				
Lease operating expenses	\$2.68	\$1.83	\$0.85	46%
Salaries, general and administrative expenses (2) ..	0.68	0.41	0.27	66%
DD&A expense on oil and gas properties.....	4.45	3.67	0.78	21%
Estimated Proved Reserves at December 31:				
Oil (MBbls).....	36,564	31,586	4,978	16%
Natural gas (MMcf)	299,554	213,083	86,471	41%
Oil and natural gas (MMcfe)	518,935	402,598	116,337	29%

(1) Includes the settlement of effective hedging contracts.

(2) Exclusive of incentive compensation expense.

For the year ended 2008, we reported a net loss totaling \$1,137.2 million, or \$35.58 per share, compared to net income for the year ended December 31, 2007 of \$181.4 million, or \$6.49 per share. All per share amounts are on a diluted basis. On August 28, 2008, we completed our acquisition of Bois d'Arc. The revenues and expenses associated with Bois d'Arc have been included in Stone's consolidated financial statements since August 28, 2008.

At the end of 2008, we recognized a ceiling test write-down of our oil and gas properties (United States and China) totaling \$1,309.4 million (\$851.1 million after taxes). At the end of 2007, we recognized a ceiling test write-down of our China oil and gas properties totaling \$8.2 million (\$5.5 million after taxes). The write-downs did not impact our cash flow from operations but did reduce net income and stockholders' equity. At December 31, 2008, approximately \$157.8 million of unevaluated costs were determined to be impaired and were reclassified to proved oil and gas properties and included in our ceiling test computation.

The 2008 net loss included a goodwill impairment charge totaling \$466.0 million (no tax effect). The goodwill impairment charge did not impact our cash flow from operations but did reduce net income and stockholders' equity. The goodwill related to our acquisition of Bois d'Arc.

Included in 2007 net income before income taxes is a \$59.8 million gain (\$40.1 million after taxes) on the sale of our Rocky Mountain Region properties, representing the excess of the proceeds from the sale over the carrying value of the oil and gas properties and other assets sold and transaction costs.

The variance in annual results was also due to the following components:

Production. Production volumes during 2008 totaled 4,916,000 barrels of oil and 34.4 Bcf of natural gas compared to 6,088,000 barrels of oil and 45.1 Bcf of natural gas produced during 2007, a decrease on a gas equivalent basis of 17.7 Bcfe. Production rates in 2008 were negatively impacted by extended Gulf Coast shut-ins due to Hurricanes Gustav and Ike, amounting to volumes of approximately 18.1 Bcfe (50 MMcfe per day). Slightly offsetting this decrease was the production associated with our Bois d'Arc acquisition, which closed on August 28, 2008, totaling approximately 6.4 Bcfe through December 31, 2008. Production rates in 2007 were negatively impacted by extended Gulf Coast shut-ins due to Hurricanes Katrina and Rita, amounting to volumes of approximately 3.6 Bcfe (10 MMcfe per day). Without the effects of the hurricane production deferrals, year to year total production volumes decreased approximately 3.2 Bcfe. The decrease was primarily the result of the sale of substantially all of our Rocky Mountain Region properties on June 29, 2007 and the divestiture of non-core Gulf of Mexico properties in the first quarter of 2008. Rocky Mountain Region production was 6.6 Bcfe for the year ended December 31, 2007.

Prices. Prices realized during 2008 averaged \$93.79 per barrel of oil and \$9.78 per Mcf of natural gas compared to 2007 average realized prices of \$69.68 per barrel of oil and \$7.30 per Mcf of natural gas. On a gas equivalent basis, average 2008 prices were 35% higher than prices realized during 2007. All unit pricing amounts include the settlement of effective hedging contracts.

We enter into various hedging contracts in order to reduce our exposure to the possibility of declining oil and gas prices. During the years ended December 31, 2008 and 2007, our effective hedging transactions increased our average realized natural gas prices by \$0.44 per Mcf and \$0.23 per Mcf, respectively. Average realized oil prices were decreased during the years ended December 31, 2008 and 2007 by \$7.01 per barrel and \$0.42 per barrel, respectively.

Income. Oil and natural gas revenue increased 6% to \$797.7 million in the year ended December 31, 2008 from \$753.3 million during the year ended December 31, 2007. The increase was due to a 35% increase in average realized prices on a gas equivalent basis, partially offset by a 22% decline in production volumes. Oil and natural gas revenue related to the properties acquired from Bois d'Arc totaled \$47.3 million from August 28, 2008 through December 31, 2008. We sold substantially all of our Rocky Mountain Region properties on June 29, 2007. Rocky Mountain Region oil and natural gas revenue amounted to \$47.4 million for the year ended December 31, 2007.

Derivative Income/Expense. During the year ended December 31, 2008, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. During the second half of 2008, as a result of extended shut-ins of production after Hurricanes Gustav and Ike, our September 2008 crude oil and natural gas production levels were below the volumes that we had hedged. Consequently, some of our crude oil and natural gas hedges for September 2008 were deemed to be ineffective. Net derivative income for the year ended December 31, 2008, totaled \$3.3 million, consisting of \$0.7 million of cash settlements on the ineffective derivative contracts, \$4.5 million of changes in the fair market value of the ineffective portion of derivative contracts, less \$1.9 million of amortization of the cost of puts. During the year ended December 31, 2007, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. Net derivative expense for the year ended December 31, 2007 totaled \$0.7 million, representing changes in the fair market value of the ineffective portion of the derivatives.

Expenses. During the year ended December 31, 2008, we incurred lease operating expenses of \$171.1 million, compared to \$149.7 million incurred during the year ended December 31, 2007. The increase in lease operating expenses was primarily the result of increased service costs and the acquisition of the Bois d'Arc properties. Included in lease operating expenses from August 28, 2008 through December 31, 2008 were \$28.6 million of expenses for the properties acquired from Bois d'Arc. On a unit of production basis, 2008 lease operating expenses were \$2.68 per Mcfe as compared to \$1.83 per Mcfe for 2007, primarily a result of the production disruption from Hurricanes Gustav and Ike and increased service costs. Partially offsetting the increase in lease operating expenses was the sale of our Rocky Mountain Region properties in June 2007. Rocky Mountain Region lease operating expenses totaled \$10.0 million for the year ended December 31, 2007.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2008 totaled \$284.7 million, or \$4.45 per Mcfe, compared to DD&A expense of \$299.2 million, or \$3.67 per Mcfe in the year ended December 31, 2007. The increase in 2008 DD&A on a unit basis was attributable to the unit cost of current year net reserve additions (including future development costs) exceeding the per unit amortizable base as of the beginning of the year.

During the years ended December 31, 2008 and 2007, salaries, general and administrative ("SG&A") expenses (exclusive of incentive compensation) totaled \$43.5 million and \$33.6 million, respectively. The increase in SG&A expenses in 2008 was primarily due to additional compensation expense associated with restricted stock issuances, higher legal fees, and the expensing of deferred financing costs associated with our amended credit facility. Included in 2007 SG&A expenses were severance and retention payments of \$2.1 million made to employees in our Denver District in connection with the sale of substantially all of our Rocky Mountain Region properties in June 2007 and the resulting discontinuation of operations of such district. Total 2007 SG&A expenses for the Denver District were \$3.8 million.

Interest expense for the year ended December 31, 2008 totaled \$13.2 million, net of \$26.4 million of capitalized interest, compared to interest of \$32.1 million, net of \$16.2 million of capitalized interest, during the year ended December 31, 2007. The decrease in interest expense in 2008 primarily related to the redemption of our Senior Floating Rate Notes due 2010 in August 2007. The decrease also resulted from an increase in capitalized interest related to unevaluated properties acquired from Bois d'Arc on August 28, 2008.

For the years ended December 31, 2008 and 2007, production taxes totaled \$8.0 million and \$9.9 million, respectively. The decrease in production taxes resulted from the sale of substantially all of our Rocky Mountain Region properties in June 2007. Rocky Mountain Region production taxes totaled \$4.0 million for the year ended December 31, 2007.

We estimate that we incurred \$7.0 million of current federal income tax expense for the year ended December 31, 2008. We had a \$31.2 million current income tax receivable at December 31, 2008 as a result of current year estimated tax payments exceeding our current estimated federal income tax liability. Our previous estimate of current taxes was adjusted downward primarily as a result of production deferrals associated with the hurricanes as well as a decline in commodity prices.

Asset Retirement Obligations. Due to falling commodity prices and hurricanes, the timing on a substantial portion of our asset retirement obligations was revised in the fourth quarter of 2008 leading to a redetermination of the present value of these obligations. In this redetermination, our credit adjusted risk free interest rate was increased to account for current credit conditions, resulting in a significant downward revision to our asset retirement obligations of approximately \$87.6 million.

Reserves. At December 31, 2008, our estimated proved oil and gas reserves totaled 518.9 Bcfe, compared to December 31, 2007 reserves of 402.6 Bcfe. The increase in estimated proved reserves during 2008 was primarily the result of the acquisition of Bois d'Arc in August 2008. Estimated proved natural gas reserves totaled 299.6 Bcf and estimated proved oil reserves totaled 36.6 MMBbls at the end of 2008. The reserve estimates at December 31, 2008 were prepared by Netherland, Sewell & Associates, Inc. in accordance with guidelines established by the SEC.

Our standardized measure of discounted future net cash flows was \$793.1 million and \$1.5 billion at December 31, 2008 and 2007, respectively. You should not assume that these estimates of future net cash flows represent the fair value of our estimated oil and natural gas reserves. As required by the SEC in 2008 and 2007, we determined these estimates of future net cash flows using market prices for oil and gas on the last day of the fiscal period. The average year-end oil and gas prices net of differentials on all of our properties used in determining these amounts, excluding the effects of hedges in place at year-end, were \$39.70 per barrel and \$5.87 per Mcf for 2008 and \$94.72 per barrel and \$7.25 per Mcf for 2007.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Forward-Looking Statements

Certain of the statements set forth under this item and elsewhere in this Form 10-K are forward-looking and are based upon assumptions and anticipated results that are subject to numerous risks and uncertainties. See **“Item 1. Business — Forward-Looking Statements”** and **“Item 1A. Risk Factors.”**

Accounting Matters and Critical Accounting Policies

Fair Value Measurements. U.S. Generally Accepted Accounting Principles (“GAAP”), as codified, establish a framework for measuring fair value and expand disclosures about fair value measurements. There is an established fair value hierarchy which has three levels based on the reliability of the inputs used to determine the fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

As of December 31, 2009, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, including our commodity derivative instruments and our investments in money market funds. Additionally, fair value concepts were applied in the recording of assets and liabilities acquired in the Bois d'Arc transaction.

Business Combinations and Goodwill. Our 2008 acquisition of Bois d'Arc was accounted for using the purchase method of accounting for business combinations. Fair value concepts were used in determining the cost of the acquired entity and allocating that cost to assets acquired (including goodwill) and liabilities assumed. Goodwill is required to be tested for impairment at least annually. There is a two-step methodology for determining impairment that begins with an estimation of the fair value of the reporting unit. The first step is a screen for potential impairment, and the second step measures the amount of impairment, if any. This authoritative guidance provided the framework for the determination of our goodwill impairment at December 31, 2008.

Asset Retirement Obligations. We are required to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property's useful life. The guidance regarding asset retirement obligations requires the use of management's estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. Our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

Full Cost Method. We follow the full cost method of accounting for our oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee and general and administrative costs (less any reimbursements for such costs) and interest incurred for the purpose of acquiring and finding oil and gas are capitalized. Unevaluated property costs are excluded from the amortization base until we have made a determination as to the existence of proved reserves on the respective property or impairment. We review our unevaluated properties at the end of each quarter to determine whether the costs should be reclassified to the full cost pool and thereby subject to amortization. Sales of oil

and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

We amortize our investment in oil and gas properties through DD&A using the units of production (“UOP”) method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period (beginning of the period reserves being determined by adding back production to end of the period reserves), and applying the respective rate to the net cost of proved oil and gas properties, including future development costs.

We capitalize a portion of the interest costs incurred on our debt that is calculated based upon the balance of our unevaluated property costs and our weighted-average borrowing rate. We also capitalize the portion of salaries, general and administrative expenses that are attributable to our acquisition, exploration and development activities.

U.S. GAAP allows the option of two acceptable methods for accounting for oil and gas properties. The successful efforts method is the allowable alternative to the full cost method. The primary differences between the two methods are in the treatment of exploration costs and in the computation of DD&A. Under the full cost method, all exploratory costs are capitalized while under the successful efforts method exploratory costs associated with unsuccessful exploratory wells and all geological and geophysical costs are expensed. Under full cost accounting, DD&A is computed on cost centers represented by entire countries while under successful efforts cost centers are represented by properties, or some reasonable aggregation of properties with common geological structural features or stratigraphic condition, such as fields or reservoirs.

Under the full cost method of accounting, we compare, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties net of related deferred taxes. We refer to this comparison as a “ceiling test.” If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows. Historically, estimated future net cash flows from proved reserves were calculated based on period-end hedge adjusted commodity prices. In December 2008, the SEC issued a final rule, “Modernization of Oil and Gas Reporting,” which adopts revisions to the SEC’s oil and gas reporting requirements. The revisions replaced the single-day year-end pricing with a twelve-month average pricing assumption. The changes to prices used in reserves calculations under the new rule are used in both disclosures and accounting impairment tests. In January 2010, the FASB issued its final standard on oil and gas reserve estimation and disclosures aligning its requirements with the SEC’s final rule. The new rules are considered a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision.

Derivative Instruments and Hedging Activities. The nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. We do not use derivative instruments for trading purposes. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet and changes in fair value are recognized in earnings.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. Our most significant estimates are:

- remaining proved oil and gas reserves volumes and the timing of their production;
- estimated costs to develop and produce proved oil and gas reserves;
- accruals of exploration costs, development costs, operating costs and production revenue;
- timing and future costs to abandon our oil and gas properties;
- the effectiveness and estimated fair value of derivative positions;
- classification of unevaluated property costs;
- capitalized general and administrative costs and interest;
- insurance recoveries related to hurricanes;
- estimates of fair value in business combinations;
- goodwill impairment testing and measurement;
- current income taxes; and
- contingencies.

For a more complete discussion of our accounting policies and procedures see our “**Notes to Consolidated Financial Statements**” beginning on page F-8.

Recent Accounting Developments

Financial Accounting Standards Board Accounting Standards Codification. The Financial Accounting Standards Board (“FASB”) voted to approve the FASB Accounting Standards Codification (the “ASC”) as the single source of authoritative nongovernmental U.S. GAAP as of July 1, 2009. The ASC is effective for interim and annual periods ending after September 15, 2009. The ASC reorganizes the many U.S. GAAP pronouncements into approximately 90 accounting topics, with all topics using a consistent structure. It also includes relevant authoritative content issued by the SEC, as well as selected SEC staff interpretations and administrative guidance. The ASC became effective for our September 30, 2009 Current Report on Form 10-Q. The ASC does not change or alter existing GAAP and will not have any impact on our consolidated financial statements. Effective July 1, 2009, changes to the ASC are communicated through an Accounting Standards Update (“ASU”).

Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. ASC 260-10 addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and are therefore required to be included in the earnings allocation in calculating earnings per share under the two-class method. Under ASC 260-10, companies are required to treat unvested share-based payment awards with a right to receive non-forfeitable dividends as a separate class of securities in calculating earnings per share. The guidance provided in ASC 260-10 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted this rule effective January 1, 2009. The net effect of the implementation of this rule on our financial statements was immaterial.

Interim Disclosures About Fair Value of Financial Instruments. ASC 825-10 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This rule became effective for us on June 15, 2009.

Subsequent Events. ASC 855-10 modifies the definition of subsequent events and requires disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. This rule became effective for us on June 15, 2009.

Fair Value Measurements and Disclosures (ASC Topic 820). ASU 2009-05 was issued in August 2009 to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities by providing clarification for measurement techniques in circumstances in which a quoted price in an active market for the identical liability is not available. This rule became effective for us on October 1, 2009.

ASU 2010-06 was issued in January 2010 to improve disclosures about fair value measurements by requiring a greater level of disaggregated information, more robust disclosures about valuation techniques and inputs to fair value measurements, information about significant transfers between the three levels in the fair value hierarchy, and separate presentation of information about purchases, sales, issuances, and settlements on a gross basis rather than as one net number. The guidance provided in ASU 2010-06 is effective for interim and annual periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

Modernization of Oil and Gas Reporting. In December 2008, the SEC issued a final rule, “Modernization of Oil and Gas Reporting,” which adopts revisions to the SEC’s oil and gas reporting requirements. It is effective January 1, 2010 for Annual Reports on Form 10-K for years ending on or after December 31, 2009, with early adoption prohibited. The revisions are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. Among other things, the revisions: (1) replace the single-day year-end pricing with a twelve-month average pricing assumption; (2) permit the reporting of probable and possible reserves in addition to the existing requirement to disclose proved reserves; (3) allow the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (4) require the disclosure of the independence and qualifications of third party preparers of reserves; and (5) require the filing of reports when a third party is relied upon to prepare or audit reserve estimates. The provisions of this new rule became effective for us for this 2009 Annual Report on Form 10-K. In January 2010, the FASB issued its final standard on oil and gas reserve estimation and disclosures aligning its requirements with the SEC’s final rule. The new rules are considered a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision. This change in accounting principle has had a material effect on the consistency of our oil and gas reserve estimates, supplemental disclosures, the calculation of DD&A and the full cost ceiling test.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure continues to be the pricing applicable to our oil and natural gas production. Our revenues, profitability and future rate of growth depend substantially upon the market prices of oil and natural gas, which fluctuate widely. Oil and natural gas price declines and volatility could adversely affect our revenues, cash flows and profitability. Price volatility is expected to continue. Assuming a 10% decline in realized oil and natural gas prices, including the effects of hedging contracts, we estimate our diluted net loss per share for 2009 would have increased approximately \$1.05 per share. In order to manage our exposure to oil and natural gas price declines, we occasionally enter into oil and natural gas price hedging arrangements to secure a price for a portion of our expected future production. Our hedging policy provides that not more than 50% of our estimated production quantities can be hedged without the consent of the board of directors.

We have entered into fixed-price swaps with various counterparties for a portion of our expected 2010 and 2011 oil and natural gas production from the Gulf Coast Basin. Some of our fixed-price gas swap settlements are based on an average of NYMEX prices for the last three days of a respective month and some are based on the NYMEX price for the last day of a respective month. The fixed-price oil swap settlements are based upon an average of the NYMEX closing price for West Texas Intermediate (“WTI”) during the entire calendar month. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price. Our outstanding fixed-price swap contracts are with J.P. Morgan Chase Bank, N.A., The Toronto-Dominion Bank, Barclays Bank PLC, BNP Paribas and The Bank of Nova Scotia.

The following table shows our hedging positions as of February 25, 2010:

	Fixed-Price Swaps			
	Natural Gas		Oil	
	Daily Volume (MMBtus/d)	Swap Price	Daily Volume (Bbls/d)	Swap Price
2010.....	20,000	\$6.97	2,000	\$63.00
2010.....	20,000	6.50	1,000	64.05
2010.....	10,000	6.50	1,000	60.20
2010.....			1,000	75.00
2010.....			1,000	75.25
2010.....			4,000 (a)	73.65
2010.....			2,000 (b)	80.10
2011.....	10,000	6.83	1,000	70.05
2011.....			1,000	78.20
2011.....			1,000	83.00
2011.....			1,000	83.05

(a) January – March

(b) April - December

We believe these positions have hedged approximately 46% of our estimated 2010 production from estimated proved reserves and 17% of our estimated 2011 production from estimated proved reserves.

Interest Rate Risk

We had long-term debt outstanding of \$575 million at December 31, 2009, of which \$400 million, or approximately 70%, bears interest at fixed rates. The \$400 million of fixed-rate debt is comprised of \$200 million of 8¼% Senior Subordinated Notes due 2011 and \$200 million of 6¾% Senior Subordinated Notes due 2014. At December 31, 2009, the remaining \$175 million of our outstanding long-term debt bears interest at a floating rate and consists of borrowings outstanding under our bank credit facility. At December 31, 2009, the weighted average interest rate under our bank credit facility was approximately 2.7%. We currently have no interest rate hedge positions in place to reduce our exposure to changes in interest rates. Assuming a 200 basis point increase in market interest rates during 2009 our interest expense, net of capitalization, would have increased approximately \$1.9 million, net of taxes, resulting in a \$.04 per diluted share increase in our reported net loss.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Information concerning this Item begins on Page F-1.

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

There have been no disagreements with our independent registered public accounting firm on our accounting or financial reporting that would require our independent registered public accounting firm to qualify or disclaim their report on our financial statements, or otherwise require disclosure in this Annual Report on Form 10-K.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that material information relating to Stone Energy Corporation and its consolidated subsidiaries (collectively “Stone”) is made known to the officers who certify Stone’s financial reports and the Board of Directors. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

Our principal executive officer and our principal financial officer, with the participation of other members of our senior management, reviewed and evaluated the effectiveness of Stone’s disclosure controls and procedures as of December 31, 2009. Based on this evaluation, our principal executive officer and principal financial officer believe:

- Stone’s disclosure controls and procedures were effective to ensure that information required to be disclosed by Stone in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms; and
- Stone’s disclosure controls and procedures were effective to ensure that information required to be disclosed by Stone in the reports that it files or submits under the Securities Exchange Act of 1934 was accumulated and communicated to Stone’s management, including Stone’s principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during the quarter ended December 31, 2009 that has materially affected, or is reasonably 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 by the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2009. In making this assessment, we used the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we have concluded that our internal controls over financial reporting were effective as of December 31, 2009. Ernst and Young LLP, an independent public accounting firm, has issued their report on the Company’s internal control over financial reporting as of December 31, 2009.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Stockholders and Board of Directors
Stone Energy Corporation

We have audited Stone Energy Corporation's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Stone Energy Corporation'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 included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, 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, Stone Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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 Stone Energy Corporation as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, changes in stockholders' equity, and comprehensive income for each of the three years in the period ended December 31, 2009 and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
February 25, 2010

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

See “**Item 4A. Executive Officers of the Registrant**” for information regarding our executive officers.

Additional information required by Item 10, including information regarding our audit committee financial experts, is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2010 Annual Meeting of Stockholders to be held on May 21, 2010. The Company has made available free of charge on its Internet Web Site (www.StoneEnergy.com) the Code of Business Conduct and Ethics applicable to all employees of the Company including the Chief Executive Officer, Chief Financial Officer and Principal Accounting Officer.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2010 Annual Meeting of Stockholders to be held on May 21, 2010.

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

The information required by Item 12 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2010 Annual Meeting of Stockholders to be held on May 21, 2010.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by Item 13 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2010 Annual Meeting of Stockholders to be held on May 21, 2010.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 is incorporated herein by reference to such information as set forth in our definitive Proxy Statement for our 2010 Annual Meeting of Stockholders to be held on May 21, 2010.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements:

The following consolidated financial statements, notes to the consolidated financial statements and the Report of Independent Registered Public Accounting Firm thereon are included beginning on page F-1 of this Form 10-K:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheet as of December 31, 2009 and 2008

Consolidated Statement of Operations for the three years in the period ended December 31, 2009

Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2009

Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2009

Consolidated Statement of Comprehensive Income for the three years in the period ended December 31, 2009

Notes to the Consolidated Financial Statements

2. Financial Statement Schedules:

All schedules are omitted because the required information is inapplicable or the information is presented in the Financial Statements or the notes thereto.

3. Exhibits:

- 3.1 Certificate of Incorporation of the Registrant, as amended (incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1 (Registration No. 33-62362)).
- 3.2 Certificate of Amendment of the Certificate of Incorporation of Stone Energy Corporation, dated February 1, 2001 (incorporated by reference to Exhibit 4.1 to the Registrant's Form 8-K, filed February 7, 2001).
- 3.3 Amended & Restated Bylaws of Stone Energy Corporation, dated May 15, 2008 (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K dated May 15, 2008 (File No. 001-12074)).
- 4.1 Indenture between Stone Energy Corporation and JPMorgan Chase Bank, National Association, as trustee, dated December 15, 2004 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on December 15, 2004.)
- 4.2 First Supplemental Indenture, dated August 28, 2008, to the Indenture between Stone Energy Corporation and JPMorgan Chase Bank dated December 10, 2001 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K dated August 27, 2008 (File No. 001-12074)).
- 4.3 First Supplemental Indenture, dated August 28, 2008, to the Indenture between Stone Energy Corporation and JPMorgan Chase Bank, National Association, as trustee, dated December 15, 2004 (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K dated August 27, 2008 (File No. 001-12074)).
- 4.4 Second Supplemental Indenture, dated January 26, 2010, among Stone Energy Corporation, Stone Energy Offshore, L.L.C., and The Bank of New York Mellon Trust Company, N.A., successor to JPMorgan Chase Bank, as trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K dated January 26, 2010 (File No. 001-12074)).
- 4.5 Indenture, dated January 26, 2010, among Stone Energy Corporation, Stone Energy Offshore, L.L.C., and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K dated January 26, 2010 (File No. 001-12074)).

- 4.6 First Supplemental Indenture, dated January 26, 2010, among Stone Energy Corporation, Stone Energy Offshore, L.L.C., and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K dated January 26, 2010 (File No. 001-12074)).
- †10.1 Deferred Compensation and Disability Agreement between TSPC and E. J. Louviere dated July 16, 1981 (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 1995 (File No. 001-12074)).
- †10.2 Stone Energy Corporation 2009 Amended and Restated Stock Incentive Plan (incorporated by reference to Appendix A to the Registrant's Definitive Proxy Statement on Schedule 14A for Stone's 2009 Annual Meeting of Stockholders (File No. 001-12074)).
- †10.3 Stone Energy Corporation Revised (2005) Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.11 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).
- †10.4 Stone Energy Corporation Amended and Restated Revised Annual Incentive Compensation Plan, dated November 14, 2007 (incorporated by reference to Exhibit 10.10 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-12074)).
- †10.5 Stone Energy Corporation Deferred Compensation Plan (incorporated by reference to Exhibit 4.5 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).
- †10.6 Adoption Agreement between Fidelity Management Trust Company and Stone Energy Corporation for the Stone Energy Corporation Deferred Compensation Plan dated December 1, 2004 (incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2004 (File No. 001-12074)).
- † 10.7 Letter Agreement dated May 19, 2005 between Stone Energy Corporation and Kenneth H. Beer (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed May 24, 2005 (File No. 001-12074)).
- †10.8 Letter Agreement dated December 2, 2008 between Stone Energy Corporation and David H. Welch (incorporated by reference to Exhibit 10.8 to the Registrant's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-12074)).
- †10.9 Letter Agreement dated June 28, 2007 between Stone Energy Corporation and Richard L. Smith (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K dated June 28, 2007 (File No. 001-12074)).
- 10.10 Amendment No.1, dated as of April 28, 2009, to the Second Amended and Restated Credit Agreement dated as of August 28, 2008, among Stone Energy Corporation, Stone Energy Offshore, L.L.C. and the financial institutions named therein (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed April 30, 2009 (File No. 001-12074)).
- 10.11 Amendment No. 2, dated January 11, 2010, to the Second Amended and Restated Credit Agreement dated as of August 28, 2008 (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K, filed January 12, 2010 (File No. 001-12074)).
- 10.12 Amended and Restated Security Agreement, dated as of August 28, 2008, among Stone Energy Corporation and the other Debtors parties hereto in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 4.5 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 001-12074)).
- †10.13 Stone Energy Corporation Executive Change of Control and Severance Plan (as amended and restated effective December 31, 2008) (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed April 8, 2009 (File No. 001-12074)).

- †10.14 Stone Energy Corporation Employee Change of Control Severance Plan (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.3 to the Registrant’s Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).
- †10.15 Stone Energy Corporation Executive Change in Control Severance Policy (as amended and restated) dated December 7, 2007 (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed December 12, 2007 (File No. 001-12074)).
- 10.16 Form of Indemnification Agreement between Stone Energy Corporation and each of its directors and executive officers (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed March 27, 2009 (File No. 001-12074)).
- *21.1 Subsidiaries of the Registrant.
- *23.1 Consent of Independent Registered Public Accounting Firm.
- *23.2 Consent of Netherland, Sewell & Associates, Inc.
- *31.1 Certification of Principal Executive Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
- *31.2 Certification of Principal Financial Officer of Stone Energy Corporation as required by Rule 13a-14(a) of the Securities Exchange Act of 1934.
- *#32.1 Certification of Chief Executive Officer and Chief Financial Officer of Stone Energy Corporation pursuant to 18 U.S.C. § 1350.
- *99.1 Report of Netherland, Sewell & Associates, Inc.

* Filed herewith.

† Identifies management contracts and compensatory plans or arrangements.

Not considered to be “filed” for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

SIGNATURES

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

STONE ENERGY CORPORATION

Date: February 25, 2010

By: /s/ David H. Welch
David H. Welch
*President and
Chief Executive Officer*

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

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ David H. Welch</u> David H. Welch	President, Chief Executive Officer and Director (principal executive officer)	February 25, 2010
<u>/s/ Kenneth H. Beer</u> Kenneth H. Beer	Senior Vice President and Chief Financial Officer (principal financial officer)	February 25, 2010
<u>/s/ J. Kent Pierret</u> J. Kent Pierret	Senior Vice President, Chief Accounting Officer and Treasurer (principal accounting officer)	February 25, 2010
<u>/s/ Robert A. Bernhard</u> Robert A. Bernhard	Director	February 25, 2010
<u>/s/ George R. Christmas</u> George R. Christmas	Director	February 25, 2010
<u>/s/ B.J. Duplantis</u> B.J. Duplantis	Director	February 25, 2010
<u>/s/ Peter D. Kinnear</u> Peter D. Kinnear	Director	February 25, 2010
<u>/s/ John P. Laborde</u> John P. Laborde	Director	February 25, 2010
<u>/s/ Richard A. Pattarozzi</u> Richard A. Pattarozzi	Director	February 25, 2010
<u>/s/ Donald E. Powell</u> Donald E. Powell	Director	February 25, 2010
<u>/s/ Kay G. Priestly</u> Kay G. Priestly	Director	February 25, 2010
<u>/s/ David R. Voelker</u> David R. Voelker	Director	February 25, 2010

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Stockholders and Board of Directors
Stone Energy Corporation

We have audited the accompanying consolidated balance sheets of Stone Energy Corporation as of December 31, 2009 and 2008, and the related consolidated statements of operations, cash flows, changes in stockholders' equity, and comprehensive income for each of the three years in the period ended December 31, 2009. 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 Stone Energy Corporation as of December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Stone Energy Corporation's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 25, 2010

STONE ENERGY CORPORATION
CONSOLIDATED BALANCE SHEET
(Amounts in thousands of dollars, except per share amounts)

<u>Assets</u>	December 31,	
	2009	2008
Current assets:		
Cash and cash equivalents.....	\$69,293	\$68,137
Accounts receivable.....	118,129	151,641
Fair value of hedging contracts.....	16,223	136,072
Deferred tax asset.....	14,571	-
Current income tax receivable.....	-	31,183
Inventory.....	8,717	35,675
Other current assets.....	814	1,413
Total current assets	227,747	424,121
Oil and gas properties – United States – full cost method of accounting:		
Proved, net of accumulated depreciation, depletion and amortization of \$4,536,599 and \$3,766,676, respectively.....	856,467	1,130,583
Unevaluated.....	329,242	493,738
Building and land, net of accumulated depreciation of \$1,840 and \$1,666, respectively.....	5,723	5,615
Fixed assets, net of accumulated depreciation of \$18,591 and \$16,742, respectively.....	4,084	5,326
Other assets, net of accumulated depreciation and amortization of \$10,419 and \$5,891, respectively.....	29,208	46,620
Fair value of hedging contracts.....	1,771	-
Total assets	\$1,454,242	\$2,106,003
<u>Liabilities and Stockholders' Equity</u>		
Current liabilities:		
Accounts payable to vendors.....	\$66,863	\$144,016
Undistributed oil and gas proceeds.....	15,280	37,882
Fair value of hedging contracts.....	34,859	-
Deferred taxes.....	-	32,416
Asset retirement obligations.....	30,515	70,709
Current income tax payable.....	11,110	-
Other current liabilities.....	42,983	15,759
Total current liabilities	201,610	300,782
Long-term debt.....	575,000	825,000
Deferred taxes.....	44,528	193,924
Asset retirement obligations.....	265,021	186,146
Fair value of hedging contracts.....	7,721	1,221
Other long-term liabilities.....	18,412	11,751
Total liabilities	1,112,292	1,518,824
Commitments and contingencies		
Stockholders' equity:		
Stone Energy Corporation stockholders' equity:		
Common stock, \$.01 par value; authorized 100,000,000 shares; issued 47,509,144 and 39,430,637 shares, respectively.....	475	394
Treasury stock (16,582 shares, respectively, at cost).....	(860)	(860)
Additional paid-in capital.....	1,324,410	1,257,633
Accumulated deficit.....	(966,695)	(754,987)
Accumulated other comprehensive income (loss).....	(15,380)	84,912
Total Stone Energy Corporation stockholders' equity.....	341,950	587,092
Non-controlling interest.....	-	87
Total stockholders' equity	341,950	587,179
Total liabilities and stockholders' equity	\$1,454,242	\$2,106,003

The accompanying notes are an integral part of this balance sheet.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF OPERATIONS
(Amounts in thousands, except per share amounts)

	Year Ended December 31,		
	2009	2008	2007
Operating revenue:			
Oil production.....	\$438,942	\$461,050	\$424,205
Gas production.....	272,353	336,665	329,047
Derivative income, net.....	3,061	3,327	-
Total operating revenue	<u>714,356</u>	<u>801,042</u>	<u>753,252</u>
Operating expenses:			
Lease operating expenses.....	156,786	171,107	149,702
Other operational expense.....	2,400	-	-
Production taxes.....	7,920	7,990	9,945
Depreciation, depletion and amortization	259,639	288,384	302,739
Write-down of oil and gas properties.....	505,140	1,309,403	8,164
Goodwill impairment.....	-	465,985	-
Accretion expense.....	33,016	17,392	17,620
Salaries, general and administrative expenses	41,367	43,504	33,584
Incentive compensation expense.....	6,402	2,315	5,117
Impairment of inventory	9,398	-	-
Derivative expenses, net	-	-	666
Total operating expenses	<u>1,022,068</u>	<u>2,306,080</u>	<u>527,537</u>
Gain on Rocky Mountain Region properties divestiture.....	-	-	59,825
Income (loss) from operations	<u>(307,712)</u>	<u>(1,505,038)</u>	<u>285,540</u>
Other (income) expenses:			
Interest expense	21,361	13,243	32,068
Interest income	(528)	(11,250)	(12,135)
Other income	(4,362)	(5,800)	(5,657)
Other expense	508	-	-
Early extinguishment of debt.....	-	-	844
Total other (income) expenses	<u>16,979</u>	<u>(3,807)</u>	<u>15,120</u>
Net income (loss) before income taxes	<u>(324,691)</u>	<u>(1,501,231)</u>	<u>270,420</u>
Provision (benefit) for income taxes:			
Current	30,376	6,998	95,579
Deferred	(143,386)	(370,921)	(6,595)
Total income taxes	<u>(113,010)</u>	<u>(363,923)</u>	<u>88,984</u>
Net income (loss).....	(211,681)	(1,137,308)	181,436
Less: Net income (loss) attributable to non-controlling interest ..	27	(77)	-
Net income (loss) attributable to Stone Energy Corporation ..	<u>(\$211,708)</u>	<u>(\$1,137,231)</u>	<u>\$181,436</u>
Basic earnings (loss) per share attributable to Stone Energy Corporation stockholders	(\$4.82)	(\$35.58)	\$6.50
Diluted earnings (loss) per share attributable to Stone Energy Corporation stockholders	(\$4.82)	(\$35.58)	\$6.49
Average shares outstanding	43,953	31,961	27,612
Average shares outstanding assuming dilution	43,953	31,961	27,723

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CASH FLOWS
(Amounts in thousands of dollars)

	Year Ended December 31,		
	2009	2008	2007
Cash flows from operating activities:			
Net income (loss).....	(\$211,681)	(\$1,137,308)	\$181,436
<i>Adjustments to reconcile net income (loss) to net cash provided by operating activities:</i>			
Depreciation, depletion and amortization	259,639	288,384	302,739
Write-down of oil and gas properties.....	505,140	1,309,403	8,164
Goodwill impairment.....	-	465,985	-
Impairment of inventory	9,398	-	-
Accretion expense.....	33,016	17,392	17,620
Deferred income tax benefit.....	(143,386)	(370,921)	(6,595)
Gain on sale of oil and gas properties	-	-	(59,825)
Settlement of asset retirement obligations	(66,780)	(49,242)	(87,144)
Non-cash stock compensation expense.....	5,944	8,405	5,395
Excess tax benefits.....	(2)	(3,045)	(1,071)
Non-cash derivative (income) expense	5,142	(2,592)	666
Early extinguishment of debt.....	-	-	844
Other non-cash expenses	1,573	1,687	2,259
Change in current income taxes.....	66,185	(87,110)	58,579
Decrease in accounts receivable	50,159	110,689	47,549
(Increase) decrease in other current assets	627	(866)	(167)
(Increase) decrease in inventory	17,561	(33,530)	-
Increase (decrease) in accounts payable	(10,200)	24,950	(900)
Decrease in other current liabilities	(14,431)	(17,780)	(4,596)
Investment in hedging contracts	-	(1,914)	-
Other.....	(117)	(109)	205
Net cash provided by operating activities	507,787	522,478	465,158
Cash flows from investing activities:			
Acquisition of Bois d'Arc Energy, Inc., net of cash acquired.....	-	(922,714)	-
Investment in oil and gas properties	(320,214)	(446,771)	(227,651)
Proceeds from sale of oil and gas properties, net of expenses	5,553	13,339	571,857
Sale of fixed assets.....	35	4	691
Investment in fixed and other assets	(1,412)	(1,765)	(85)
Acquisition of non-controlling interest in subsidiary	(41)	-	-
Net cash provided by (used in) investing activities.....	(316,079)	(1,357,907)	344,812
Cash flows from financing activities:			
Proceeds from bank borrowings	-	425,000	-
Repayments of bank borrowings.....	(250,000)	-	(172,000)
Redemption of senior floating rate notes	-	-	(225,000)
Deferred financing costs	(141)	(8,766)	(855)
Excess tax benefits.....	2	3,045	1,071
Proceeds from stock offering, net of expenses.....	60,447	(54)	-
Purchase of treasury stock	(347)	(6,724)	-
Net proceeds from exercise of stock options and vesting of restricted stock.....	(513)	15,939	3,078
Net cash provided by (used in) financing activities	(190,552)	428,440	(393,706)
Net increase (decrease) in cash and cash equivalents.....	1,156	(406,989)	416,264
Cash and cash equivalents, beginning of year	68,137	475,126	58,862
Cash and cash equivalents, end of year.....	\$69,293	\$68,137	\$475,126
Supplemental disclosures of cash flow information:			
Cash paid (refunded) during the year for:			
Interest (net of amount capitalized)	\$20,623	\$13,001	\$34,083
Income taxes	(35,920)	94,109	36,771

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(Amounts in thousands of dollars)

Stone Energy Corporation Stockholders							
	<u>Common Stock</u>	<u>Treasury Stock</u>	<u>Additional Paid-In Capital</u>	<u>Retained Earnings</u>	<u>Accumulated Other Comprehensive Income (Loss)</u>	<u>Non- controlling Interest</u>	<u>Total Stockholders' Equity</u>
Balance, December 31, 2006	\$276	(\$1,161)	\$502,747	\$200,929	\$8,849	\$ -	\$711,640
Net income	-	-	-	181,436	-	-	181,436
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	(19,584)	-	(19,584)
Exercise of stock options and vesting of restricted stock	2	-	3,076	-	-	-	3,078
Amortization of stock compensation expense	-	-	8,774	-	-	-	8,774
Tax benefit from stock option exercises and restricted stock vesting	-	-	458	-	-	-	458
Balance, December 31, 2007	278	(1,161)	515,055	382,365	(10,735)	-	885,802
Net loss	-	-	-	(1,137,231)	-	(77)	(1,137,308)
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	95,647	-	95,647
Exercise of stock options and vesting of restricted stock	5	-	15,934	-	-	-	15,939
Amortization of stock compensation expense	-	-	12,906	-	-	-	12,906
Tax benefit from stock option exercises and restricted stock vesting	-	-	2,740	-	-	-	2,740
Non-controlling interest in subsidiary	-	-	-	-	-	164	164
Issuance of common stock	113	-	717,720	-	-	-	717,833
Cancellation of treasury stock	(2)	-	(6,722)	-	-	-	(6,724)
Issuance of treasury stock	-	301	-	(121)	-	-	180
Balance, December 31, 2008	394	(860)	1,257,633	(754,987)	84,912	87	587,179
Net income (loss)	-	-	-	(211,708)	-	27	(211,681)
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	(100,292)	-	(100,292)
Acquisition of non-controlling interest	-	-	73	-	-	(114)	(41)
Exercise of stock options and vesting of restricted stock	-	-	(514)	-	-	-	(514)
Amortization of stock compensation expense	-	-	8,845	-	-	-	8,845
Tax deficit from stock option exercises and restricted stock vesting	-	-	(1,647)	-	-	-	(1,647)
Stock repurchase and cancellation	-	-	(346)	-	-	-	(346)
Issuance of common stock	81	-	60,366	-	-	-	60,447
Balance, December 31, 2009	\$475	(\$860)	\$1,324,410	(\$966,695)	(\$15,380)	\$ -	\$341,950

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
(Amounts in thousands of dollars)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	(\$211,708)	(\$1,137,231)	\$181,436
Other comprehensive income (loss) net of tax effect:			
Adjustment for fair value accounting of derivatives	(100,292)	95,647	(19,584)
Comprehensive income (loss)	(312,000)	(1,041,584)	161,852
Comprehensive income (loss) attributable to non-controlling interest	-	-	-
Comprehensive income (loss) attributable to Stone Energy Corporation	(\$312,000)	(\$1,041,584)	\$161,852

The accompanying notes are an integral part of this statement.

STONE ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Amounts in thousands of dollars, except per share and price amounts)

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Stone Energy Corporation is an independent oil and natural gas company engaged in the acquisition and subsequent exploration, development, and operation of oil and gas properties located primarily in the Gulf of Mexico (“GOM”). We are also active in the Appalachia region. In 2008, we acquired Bois d’Arc Energy, Inc. (“Bois d’Arc”), an independent exploration company which was engaged in the discovery and production of oil and natural gas in the GOM. Prior to November 30, 2008, we participated in an exploratory joint venture in Bohai Bay, China. Prior to June 29, 2007, we also had significant operations in the Rocky Mountain Basins and the Williston Basin (“Rocky Mountain Region”). Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508. We have additional offices in Houston, Texas and Morgantown, West Virginia.

A summary of significant accounting policies followed in the preparation of the accompanying consolidated financial statements is set forth below.

Basis of Presentation:

The financial statements include our accounts and the accounts of our wholly owned subsidiaries, Stone Energy Offshore, L.L.C. (“Stone Offshore”), Stone Energy, L.L.C. and Caillou Boca Gathering, LLC (“Caillou Boca”). From August 2008 to the second quarter of 2009, Caillou Boca was a majority owned subsidiary. During the second quarter of 2009, we acquired the entire non-controlling interest in Caillou Boca. All intercompany balances have been eliminated. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates:

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. Estimates are used primarily when accounting for depreciation, depletion and amortization, unevaluated property costs, estimated future net cash flows from proved reserves, cost to abandon oil and gas properties, taxes, reserves of accounts receivable, accruals of capitalized costs, operating costs and production revenue, capitalized general and administrative costs and interest, insurance recoveries related to hurricanes, effectiveness and fair value of derivative instruments, the purchase price allocation on properties acquired, estimates of fair value in business combinations, goodwill impairment testing and measurement, and contingencies.

Fair Value Measurements:

U.S. Generally Accepted Accounting Principles (“GAAP”) establish a framework for measuring fair value and expand disclosures about fair value measurements. As of December 31, 2009, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, including our commodity derivative instruments and our investments in money market funds. Additionally, fair value concepts were applied in the recording of assets and liabilities acquired in the Bois d’Arc transaction (see **Note 7 - Fair Value Measurements**).

Cash and Cash Equivalents:

We consider all money market funds and highly liquid investments in overnight securities through our commercial bank accounts, which result in available funds on the next business day, to be cash and cash equivalents.

Oil and Gas Properties:

We follow the full cost method of accounting for oil and gas properties. Under this method, all acquisition, exploration, development and estimated abandonment costs, including certain related employee and general and administrative costs (less any reimbursements for such costs) and interest incurred for the purpose of finding oil and gas are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals and other costs related to such activities. Employee, general and administrative costs that are capitalized include salaries and all related fringe benefits paid to employees directly engaged in the acquisition, exploration and development of oil and gas properties, as well as all other directly identifiable general and administrative costs associated with such activities, such as rentals, utilities and insurance. We capitalize a portion of the interest costs incurred on our debt that is calculated based upon the balance of our unevaluated property costs and our weighted-average borrowing rate. Employee, general and administrative costs associated with production operations and general corporate activities are expensed in the period incurred. Additionally, workover and

maintenance costs incurred solely to maintain or increase levels of production from an existing completion interval are charged to lease operating expense in the period incurred.

U.S. GAAP allows the option of two acceptable methods for accounting for oil and gas properties. The successful efforts method is the allowable alternative to the full cost method. The primary differences between the two methods are in the treatment of exploration costs and in the computation of depreciation, depletion and amortization (“DD&A”). Under the full cost method, all exploratory costs are capitalized while under the successful efforts method exploratory costs associated with unsuccessful exploratory wells and all geological and geophysical costs are expensed. Under full cost accounting, DD&A is computed on cost centers represented by entire countries while under successful efforts cost centers are represented by properties, or some reasonable aggregation of properties with common geological structural features or stratigraphic condition, such as fields or reservoirs.

We amortize our investment in oil and gas properties through DD&A using the units of production (“UOP”) method. Under the UOP method, the quarterly provision for DD&A is computed by dividing production volumes for the period by the total proved reserves as of the beginning of the period (beginning of the period reserves being determined by adding back production to end of the period reserves), and applying the respective rate to the net cost of proved oil and gas properties, including future development costs.

Under the full cost method of accounting, we compare, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties net of related deferred taxes. We refer to this comparison as a “ceiling test.” If the net capitalized costs of proved oil and gas properties exceed the estimated discounted future net cash flows from proved reserves, we are required to write-down the value of our oil and gas properties to the value of the discounted cash flows (See **Note 4 – Investment in Oil and Gas Properties**). Historically, estimated future net cash flows from proved reserves were calculated based on period-end hedge adjusted commodity prices, and the impact of price increases subsequent to the period end could be considered. In December 2008, the Securities and Exchange Commission (“SEC”) issued a final rule, “Modernization of Oil and Gas Reporting,” which adopts revisions to the SEC’s oil and gas reporting requirements. The revisions replaced the single-day year-end pricing with a twelve-month average pricing assumption. Additionally, consideration of the impact of subsequent price increases after period end is no longer allowed. The changes to prices used in reserves calculations under the new rule are used in both disclosures and accounting impairment tests. In January 2010, the Financial Accounting Standards Board (“FASB”) issued its final standard on oil and gas reserve estimation and disclosures aligning its requirements with the SEC’s final rule. The new rules are considered a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision.

Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Asset Retirement Obligations:

U.S. GAAP requires us to record our estimate of the fair value of liabilities related to future asset retirement obligations in the period the obligation is incurred. Asset retirement obligations relate to the removal of facilities and tangible equipment at the end of an oil and gas property’s useful life. The application of this rule requires the use of management’s estimates with respect to future abandonment costs, inflation, market risk premiums, useful life and cost of capital. U.S. GAAP requires that our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

Building and Land:

Building and land are recorded at cost. Our office building in Lafayette, Louisiana is being depreciated on the straight-line method over its estimated useful life of 39 years.

Inventory:

We maintain an inventory of tubular goods. Items remain in inventory until dedicated to specific projects, at which time they are transferred to oil and gas properties. Items are carried at the lower of cost or market applied to items specifically identified.

Business Combinations and Goodwill:

Our 2008 acquisition of Bois d’Arc was accounted for using the purchase method of accounting for business combinations. We applied fair value concepts in determining the cost of the acquired entity and allocating that cost to the assets acquired (including goodwill) and liabilities assumed. U.S. GAAP requires the testing for impairment of goodwill at least annually. It establishes a two-step methodology for determining impairment that begins with an estimation of the fair value of the reporting unit. The first step is a screen for potential impairment, and the second step measures the amount of impairment, if any. This authoritative guidance provided the framework for the determination of our goodwill impairment at December 31, 2008.

Earnings Per Common Share:

Earnings per common share was calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year. Earnings per common share assuming dilution was calculated by dividing net income applicable to common stock by the weighted-average number of common shares outstanding during the year plus the weighted-average number of outstanding dilutive stock options and restricted stock granted to outside directors, officers and employees. There were no dilutive shares for the years ended December 31, 2009 and 2008 because we had net losses for those years. There were approximately 110,000 weighted-average dilutive shares for the year ended December 31, 2007. Stock options that were considered antidilutive because the exercise price of the stock exceeded the average price for the applicable period totaled approximately 747,000 shares during 2007.

During the years ended December 31, 2009, 2008 and 2007, approximately 129,000, 567,000 and 209,000 shares of common stock, respectively, were issued, from either authorized shares or shares held in treasury, upon the exercise of stock options and vesting of restricted stock by employees and non-employee directors and the awarding of employee bonus stock pursuant to the 2004 Amended and Restated Stock Incentive Plan. During the year ended December 31, 2009, 100,000 shares of common stock were repurchased under our stock repurchase program. On June 10, 2009, 8,050,000 shares of our common stock were issued in a public offering (see **Note 5 - Public Offering**). During the year ended December 31, 2008, 200,000 shares of common stock were repurchased under our stock repurchase program. On August 28, 2008, 11,301,751 shares of common stock were issued upon the completion of our acquisition of Bois d'Arc (see **Note 6 - Acquisitions and Divestitures**).

Under U.S. GAAP, instruments granted in share-based payment transactions are participating securities prior to vesting and are therefore required to be included in the earnings allocation in calculating earnings per share under the two-class method. Companies are required to treat unvested share-based payment awards with a right to receive non-forfeitable dividends as a separate class of securities in calculating earnings per share. This rule became effective for us on January 1, 2009 and the net effect of its implementation on our financial statements was immaterial.

Production Revenue:

We recognize production revenue under the entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of the company's net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sales price in effect at the time of production.

Income Taxes:

Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. For financial reporting purposes, all exploratory and development expenditures, including future abandonment costs, related to evaluated projects are capitalized and depreciated, depleted and amortized on the UOP method. For income tax purposes, only the equipment and leasehold costs relative to successful wells are capitalized and recovered through depreciation or depletion. Generally, most other exploratory and development costs are charged to expense as incurred; however, we follow certain provisions of the Internal Revenue Code that allow capitalization of intangible drilling costs where management deems appropriate. Other financial and income tax reporting differences occur as a result of statutory depletion, different reporting methods for sales of oil and gas reserves in place, different reporting methods used in the capitalization of employee, general and administrative and interest expenses, and different reporting methods for stock-based compensation.

Derivative Instruments and Hedging Activities:

The nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is considered effective. Additionally, monthly settlements of effective hedges are reflected in revenue from oil and gas production and cash flow from operations. Instruments not qualifying for hedge accounting treatment are recorded in the balance sheet at fair value and changes in fair value are recognized in earnings through derivative expense (income).

Stock-Based Compensation:

We record stock-based compensation based on the grant date fair value of issued stock options and restricted stock over the vesting period of the instrument. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The fair value of restricted shares is determined based on the average of the high and low prices on the grant date.

Recent Accounting Developments:

Financial Accounting Standards Board Accounting Standards Codification. The FASB voted to approve the FASB Accounting Standards Codification (the “ASC”) as the single source of authoritative nongovernmental U.S. GAAP as of July 1, 2009. The ASC is effective for interim and annual periods ending after September 15, 2009. The ASC reorganizes the many U.S. GAAP pronouncements into approximately 90 accounting topics, with all topics using a consistent structure. It also includes relevant authoritative content issued by the SEC, as well as selected SEC staff interpretations and administrative guidance. The ASC became effective for our September 30, 2009 Current Report on Form 10-Q. The ASC does not change or alter existing GAAP and will not have any impact on our consolidated financial statements. Effective July 1, 2009, changes to the ASC are communicated through an Accounting Standards Update (“ASU”).

Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. ASC 260-10 addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and are therefore required to be included in the earnings allocation in calculating earnings per share under the two-class method. Under ASC 260-10, companies are required to treat unvested share-based payment awards with a right to receive non-forfeitable dividends as a separate class of securities in calculating earnings per share. The guidance provided in ASC 260-10 is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted this rule effective January 1, 2009. The net effect of the implementation of this rule on our financial statements was immaterial.

Interim Disclosures About Fair Value of Financial Instruments. ASC 825-10 requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This rule became effective for us on June 15, 2009.

Subsequent Events. ASC 855-10 modifies the definition of subsequent events and requires disclosure of the date through which an entity has evaluated subsequent events and the basis for that date. This rule became effective for us on June 15, 2009.

Fair Value Measurements and Disclosures (ASC Topic 820). ASU 2009-05 was issued in August 2009 to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities by providing clarification for measurement techniques in circumstances in which a quoted price in an active market for the identical liability is not available. The guidance provided in ASU 2009-05 became effective for us on October 1, 2009.

ASU 2010-06 was issued in January 2010 to improve disclosures about fair value measurements by requiring a greater level of disaggregated information, more robust disclosures about valuation techniques and inputs to fair value measurements, information about significant transfers between the three levels in the fair value hierarchy, and separate presentation of information about purchases, sales, issuances, and settlements on a gross basis rather than as one net number. The guidance provided in ASU 2010-06 is effective for interim and annual periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years.

Modernization of Oil and Gas Reporting. In December 2008, the SEC issued a final rule, “Modernization of Oil and Gas Reporting,” which adopts revisions to the SEC’s oil and gas reporting requirements. It became effective January 1, 2010 for Annual Reports on Form 10-K for years ending on or after December 31, 2009, with early adoption prohibited. The revisions are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. Among other things, the revisions: (1) replace the single-day year-end pricing with a twelve-month average pricing assumption; (2) permit the reporting of probable and possible reserves in addition to the existing requirement to disclose proved reserves; (3) allow the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (4) require the disclosure of the independence and qualifications of third party preparers of reserves; and (5) require the filing of reports when a third party is relied upon to prepare or audit reserve estimates. The provisions of this new rule became effective for us for this 2009 Annual Report on Form 10-K. In January 2010, the FASB issued its final standard on oil and gas reserves estimation and disclosures (ASU 2010-03) aligning its requirements with the SEC’s final rule. The new rules are considered a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision. This change in accounting principle has had a material effect on the consistency of our oil and gas reserve estimates, supplemental disclosures, the calculation of DD&A and the full cost ceiling test.

NOTE 2 — ACCOUNTS RECEIVABLE:

In our capacity as operator for our co-venturers, we incur drilling and other costs that we bill to the respective parties based on their working interests. We also receive payments for these billings and, in some cases, for billings in advance of incurring costs. Our accounts receivable are comprised of the following amounts:

	As of December 31,	
	2009	2008
Accounts Receivable:		
Other co-venturers	\$6,831	\$10,701
Trade	77,948	87,420
Insurance receivable on hurricane claims	28,629	19,899
Officers and employees	36	25
Unbilled accounts receivable	4,685	33,596
	<u>\$118,129</u>	<u>\$151,641</u>

We have accrued insurance receivables on hurricane claims to the extent we have concluded the insurance recovery is probable. The accrual is for all costs previously recorded in our financial statements including asset retirement obligations and repair expenses included in lease operating expenses. Included in other long term-assets at December 31, 2009 and 2008 is \$14,601 and \$28,509, respectively, of accrued hurricane insurance reimbursements attributable to asset retirement obligations estimated to be completed in time frames greater than one year.

NOTE 3 — CONCENTRATIONS:

Sales to Major Customers

Our production is sold on month-to-month contracts at prevailing prices. We have attempted to diversify our sales and obtain credit protections such as parental guarantees from certain of our purchasers. The following table identifies customers from whom we derived 10% or more of our total oil and gas revenue during the years ended:

	December 31,		
	2009	2008	2007
Chevron U.S.A., Inc.....	(a)	18%	19%
Conoco, Inc.....	27%	29%	16%
Hess Corporation	11%	(a)	(a)
Sequent Energy Management LP.....	13%	(a)	(a)
Shell Trading (US) Company	34%	16%	11%

(a) Less than 10 percent

The maximum amount of credit risk exposure at December 31, 2009 relating to these customers amounted to \$64,617.

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.

Production and Reserve Volumes

Approximately 100% of our production during 2009 was associated with our Gulf Coast Basin properties and 99.6% of our estimated proved reserves (unaudited) at December 31, 2009 were derived from Gulf Coast Basin reservoirs.

Cash and Cash Equivalents

Substantially all of our cash balances are in excess of federally insured limits. At December 31, 2009 approximately \$15,867 was invested in the J.P. Morgan Prime Money Market Fund (Capital Shares). An additional \$26,928 was in accounts at J.P. Morgan Chase & Co.

NOTE 4 — INVESTMENT IN OIL AND GAS PROPERTIES:

The following table discloses certain financial data relative to our oil and gas producing activities located onshore and offshore the continental United States:

	Year Ended December 31,		
	2009	2008	2007
Oil and gas properties – United States, proved and unevaluated:			
Balance, beginning of year	\$5,390,997	\$3,310,074	\$4,450,808
Costs incurred during the year (capitalized):			
Acquisition costs, net of sales of unevaluated properties.....	9,072	1,830,468	18,730
Exploratory costs	78,582	146,303	16,556
Development costs (1)	199,375	59,586	154,507
Sale of Rocky Mountain Region properties	-	-	(1,363,939)
Salaries, general and administrative costs.....	19,107	19,507	20,176
Interest	25,573	25,195	13,419
Less: overhead reimbursements	(398)	(136)	(183)
Total costs incurred during the year, net of divestitures	<u>331,311</u>	<u>2,080,923</u>	<u>(1,140,734)</u>
Balance, end of year.....	<u>\$5,722,308</u>	<u>\$5,390,997</u>	<u>\$3,310,074</u>
Accumulated depreciation, depletion and amortization (DD&A):			
Balance, beginning of year	(\$3,766,676)	(\$2,158,327)	(\$2,706,936)
Provision for DD&A.....	(253,790)	(284,672)	(299,182)
Write-down of oil and gas properties.....	(505,140)	(1,278,421)	-
Sale of proved properties	(10,993)	(45,256)	847,791
Balance, end of year.....	<u>(\$4,536,599)</u>	<u>(\$3,766,676)</u>	<u>(\$2,158,327)</u>
Net capitalized costs – United States (proved and unevaluated).....	<u>\$1,185,709</u>	<u>\$1,624,321</u>	<u>\$1,151,747</u>
DD&A per Mcfe	<u>\$3.23</u>	<u>\$4.45</u>	<u>\$3.67</u>

(1) Includes asset retirement costs of \$11,607, (\$96,346) and \$20,171, respectively.

Costs incurred during the year (expensed):			
Lease operating expenses.....	\$156,786	\$171,107	\$149,702
Production taxes.....	7,920	7,990	9,945
Accretion expense.....	33,016	17,392	17,620
Expensed costs – United States.....	<u>\$197,722</u>	<u>\$196,489</u>	<u>\$177,267</u>

In December 2008, the SEC issued a final rule, “Modernization of Oil and Gas Reporting,” which adopts revisions to the SEC’s oil and gas reporting requirements. It became effective January 1, 2010 for Annual Reports on Form 10-K for years ending on or after December 31, 2009. The revisions replaced the single-day year-end pricing with a twelve-month average pricing assumption. Changes to prices used in reserves calculations are used in both disclosures and accounting impairment tests. At December 31, 2009, our ceiling test computation (See Note 1) resulted in a write-down of our U.S. oil and gas properties of \$165,057 based on twelve-month average prices of \$58.95 per barrel of oil and \$3.49 per Mcf of natural gas. The benefit of hedges in place at December 31, 2009 reduced the write-down by \$94,541. At March 31, 2009, our ceiling test computation resulted in a write-down of our U.S. oil and gas properties of \$340,083 based on a March 31, 2009 Henry Hub gas price of \$3.63 per MMBtu and a West Texas Intermediate oil price of \$44.92 per barrel. At December 31, 2008, our ceiling test computation resulted in a write-down of our U.S. oil and gas properties, which included assets acquired in the Bois d’Arc transaction, of \$1,278,421 based on a December 31, 2008 Henry Hub gas price of \$5.71 per MMBtu and a West Texas Intermediate oil price of \$41.00 per barrel. The benefit of hedges in place at December 31, 2008 reduced the write-down by \$177,729.

The following table discloses net costs incurred (evaluated) on our unevaluated properties located in the United States for the years indicated:

Unevaluated oil and gas properties – United States	2009	2008	2007
Net costs incurred (evaluated) during year:			
Acquisition costs	(\$203,776)	\$308,325	\$29,461
Exploration costs.....	15,337	24,531	(5,396)
Capitalized interest.....	23,943	10,314	10,212
	<u>(\$164,496)</u>	<u>\$343,170</u>	<u>\$34,277</u>

During 2006, we entered into an agreement to participate in the drilling of exploratory wells on two offshore concessions in Bohai Bay, China. After the drilling of three wells, we decided in 2008 not to pursue any additional investments in this area. As a result of this decision, we fully impaired our capitalized costs from activities in China in 2008. The following table discloses certain financial data relative to our oil and gas exploration activities located in Bohai Bay, China:

	Year Ended December 31,	
	2008	2007
Oil and gas properties – China:		
Balance, beginning of year	\$37,729	\$40,553
Costs incurred during the year (capitalized):		
Exploratory costs	226	(5,590)
Salaries, general and administrative costs.....	31	-
Interest	1,160	2,766
Total costs incurred during the year.....	<u>1,417</u>	<u>(2,824)</u>
Balance, end of year (fully evaluated at December 31, 2008 and unevaluated at December 31, 2007).....	<u>\$39,146</u>	<u>\$37,729</u>
Accumulated depreciation, depletion and amortization (DD&A):		
Balance, beginning of year	(\$8,164)	\$ -
Write-down of oil and gas properties.....	<u>(30,982)</u>	<u>(8,164)</u>
Balance, end of year.....	<u>(\$39,146)</u>	<u>(\$8,164)</u>
Net capitalized costs – China.....	<u>\$ -</u>	<u>\$29,565</u>

The following table discloses financial data associated with unevaluated costs in the United States at December 31, 2009:

	Balance as of December 31, 2009	Net Costs Incurred (Evaluated) During the Year Ended December 31,			
		2009	2008	2007	2006 and prior
Acquisition costs	\$181,429	(\$2,326)	\$164,637	\$8,160	\$10,958
Exploration costs	116,399	42,691	25,543	24,243	23,922
Capitalized interest	31,414	19,163	124	6,958	5,169
Total unevaluated costs	<u>\$329,242</u>	<u>\$59,528</u>	<u>\$190,304</u>	<u>\$39,361</u>	<u>\$40,049</u>

Approximately 115 specifically identified drilling projects are included in unevaluated costs at December 31, 2009 and are expected to be evaluated in the next four years. The excluded costs will be included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. Interest costs capitalized on unevaluated properties during the years ended December 31, 2009, 2008 and 2007 totaled \$25,573, \$26,355 and \$16,185, respectively.

NOTE 5 — PUBLIC OFFERING:

In June 2009, we sold 8,050,000 shares of our common stock in a public offering at a price of \$8.00 per share resulting in net proceeds of approximately \$60,447 after deducting the underwriting discount and offering expenses. The net proceeds are reflected in the common stock and additional paid-in capital accounts of our condensed consolidated balance sheet at December 31, 2009.

NOTE 6 — ACQUISITIONS AND DIVESTITURES:

Acquisitions

On August 28, 2008, we completed the acquisition of Bois d'Arc in a cash and stock transaction totaling approximately \$1,653,312. Bois d'Arc was an independent exploration company engaged in the discovery and production of oil and natural gas in the Gulf of Mexico. The primary factors considered by management in making the acquisition included the belief that the merger would position the combined company as one of the largest independent Gulf of Mexico-focused exploration and production companies, with a solid production base, a strong portfolio for continued development of proved and probable reserves, and an extensive inventory of exploration opportunities. Pursuant to the terms and conditions of the agreement and plan of merger, Stone paid total merger consideration of approximately \$935,425 in cash and issued approximately 11.3 million common shares, valued at \$63.52 per share. The per share value of the Stone common shares issued was calculated as the average of Stone's closing share price for the two days prior to through the two days after the merger announcement date of April 30, 2008. The cash component of the merger consideration was funded with approximately \$510,425 of cash on hand and \$425,000 of borrowings from our amended and restated bank credit facility.

The acquisition was accounted for using the purchase method of accounting for business combinations. The acquisition was preliminarily recorded in Stone's consolidated financial statements on August 28, 2008, the date the acquisition closed. The preliminary purchase price allocation was adjusted in the fourth quarter of 2008 as a result of further analysis of the assets acquired, principally proved and unevaluated oil and gas properties, and liabilities assumed, principally asset retirement obligations and deferred taxes, which resulted in an adjustment to the preliminary allocation to goodwill. The adjustments were the result of additional analysis of proved, probable and possible reserves at the time of the acquisition. The following table represents the allocation of the total purchase price of Bois d'Arc to the acquired assets and liabilities of Bois d'Arc.

Fair value of Bois d'Arc's net assets:	
Net working capital, including cash of \$15,333	\$27,865
Proved oil and gas properties	1,339,117
Unevaluated oil and gas properties	422,183
Fixed and other assets	333
Goodwill	465,985
Deferred tax liability	(467,872)
Dismantlement reserve	(4,239)
Asset retirement obligations	(127,380)
Total fair value of net assets	<u>\$1,655,992</u>

The following table represents the breakdown of the consideration paid for Bois d'Arc's net assets.

Consideration paid for Bois d'Arc's net assets:	
Cash consideration paid	\$935,425
Stone common stock issued	<u>717,887</u>
Aggregate purchase consideration issued to Bois d'Arc stockholders	1,653,312
Plus:	
Direct merger costs (1)	<u>2,680</u>
Total purchase price	<u>\$1,655,992</u>

(1) Direct merger costs include legal and accounting fees, printing fees, investment banking expenses and other merger-related costs.

The allocation of the purchase price included \$465,985 of asset valuation attributable to goodwill. Goodwill represents the amount by which the total purchase price exceeds the aggregate fair values of the assets acquired and liabilities assumed in the merger, other than goodwill. Goodwill was not deductible for tax purposes. Goodwill is required to be tested for impairment at least annually. We tested goodwill created in the Bois d'Arc acquisition for impairment on December 31, 2008. A substantial reduction in commodity prices and the existence of a full cost ceiling test write-down in the fourth quarter of 2008 were indications of potential impairment. The reporting unit for the impairment test was Stone Energy Corporation and its consolidated subsidiaries. The fair value of the reporting unit was determined using average quoted market prices for Stone common stock for the two market days prior to through the two market days after December 31, 2008. A control premium of 25% was applied to the market capitalization. The control premium was based on a history of control premiums paid for the acquisition of entities in similar industries. The resulting fair value of the reporting unit was \$504,025 below the reporting unit's carrying value. Additional analysis indicated no implied value of the recorded goodwill, resulting in the impairment of the entire amount of goodwill of \$465,985 at December 31, 2008.

The following summary pro forma combined statement of operations data of Stone for the years ended December 31, 2008 and 2007 has been prepared to give effect to the merger as if it had occurred on January 1, 2008 and 2007, respectively. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2008 and 2007 and is not intended to be a projection of future results. Future results may vary significantly from the results reflected in the following pro forma financial information because of normal production declines, changes in commodity prices, future acquisitions and divestitures, future development and exploration activities, and other factors.

	Year Ended December 31,	
	2008	2007
Revenues	\$1,161,761	\$1,108,712
Income (loss) from operations	(1,409,589)	294,721
Net income (loss)	(1,083,322)	179,940
Basic earnings (loss) per share	(\$27.52)	\$4.62
Diluted earnings (loss) per share	(\$27.52)	\$4.61

Divestitures

In the second quarter of 2009, we completed the sale of an onshore Louisiana field for cash consideration of approximately \$4,909. The estimated asset retirement obligation for this field was \$5,941. The sale of these properties was accounted for as an adjustment of capitalized costs with no gain or loss recognized. In the first quarter of 2008, we completed the divestiture of a small package of Gulf of Mexico properties which totaled 17.4 Bcfe of reserves at December 31, 2007 for a cash consideration of approximately \$14,100 after closing adjustments. The properties that were sold had estimated asset retirement obligations of \$32,890.

On June 29, 2007, we completed the sale of substantially all of our Rocky Mountain Region properties and related assets to Newfield Exploration Company for a total consideration of \$581,958. At December 31, 2006, the estimated proved reserves associated with these assets totaled 182.4 Bcfe, which represented 31% of our estimated proved oil and natural gas reserves. Sales of oil and gas properties under the full cost method of accounting are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless the adjustment significantly alters the relationship between capitalized costs and reserves.

Since the sale of these oil and gas properties would significantly alter that relationship, we recognized a net gain on the sale of \$59,825, computed as follows:

Proceeds from the sale (after post-closing adjustments).....	\$581,958
Add: Transfer of asset retirement and other obligations.....	1,823
Less: Transaction costs	(6,088)
Carrying value of oil and gas properties	(516,148)
Carrying value of other assets.....	<u>(1,720)</u>
Net gain on sale	<u>\$59,825</u>

The carrying value of the properties sold was computed by allocating total capitalized costs within the U.S. full cost pool between properties sold and properties retained based on their relative fair values.

NOTE 7 – FAIR VALUE MEASUREMENTS:

U.S. GAAP establishes a fair value hierarchy which has three levels based on the reliability of the inputs used to determine the fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions. Effective June 15, 2009, disclosures about the fair value of financial instruments are required for interim reporting periods of publicly traded companies as well as in annual financial statements.

As of December 31, 2009, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, including our commodity derivative instruments and our investments in money market funds. We utilize the services of an independent third party to assist us in valuing our derivative instruments. We used the income approach in determining the fair value of our derivative instruments utilizing a proprietary pricing model. The model accounts for the credit risk of Stone and its counterparties in the discount rate applied to estimated future cash inflows and outflows. Our swap contracts are included within the Level 2 fair value hierarchy and collar contracts are included within the Level 3 fair value hierarchy. Significant unobservable inputs used in establishing fair value for the collars were the volatility impacts in the pricing model as it relates to the call portion of the collar. For a more detailed description of our derivative instruments, see **Note 13 - Derivative Instruments and Hedging Activities**. We used the market approach in determining the fair value of our investments in money market funds, which are included within the Level 1 fair value hierarchy.

The following tables present our assets and liabilities that are measured at fair value on a recurring basis during the year ended December 31, 2009.

Fair Value Measurements at December 31, 2009				
Assets	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money market funds	\$15,867	\$15,867	\$ -	\$ -
Hedging contracts	17,994	-	17,994	-
Total	<u>\$33,861</u>	<u>\$15,867</u>	<u>\$17,994</u>	<u>\$ -</u>

Fair Value Measurements at December 31, 2009				
Liabilities	Total	Quoted Prices in Active Markets for Identical Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Hedging contracts	(\$42,580)	\$ -	(\$42,580)	\$ -
Total	<u>(\$42,580)</u>	<u>\$ -</u>	<u>(\$42,580)</u>	<u>\$ -</u>

The table below presents a reconciliation for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the year ended December 31, 2009.

	Hedging Contracts, net
Balance as of January 1, 2009.....	\$68,123
Total gains/(losses) (realized or unrealized):	
Included in earnings.....	94,934
Included in other comprehensive income	(65,953)
Purchases, sales, issuances and settlements	(97,104)
Transfers in and out of Level 3	-
Balance as of December 31, 2009.....	<u>\$ -</u>
 The amount of total gains/(losses) for the period included in earnings attributable to the change in unrealized gain/(losses) relating to derivatives still held at December 31, 2009	 <u>\$ -</u>

We have applied fair value concepts in recording the assets and liabilities acquired in our acquisition of Bois d'Arc (see **Note 6 - Acquisitions and Divestitures**). In determining the fair value of Bois d'Arc's most significant assets, proved and unevaluated oil and gas properties, we used elements of both the income and market approaches. Future income for oil and gas properties was estimated based on proved, probable, possible and prospective reserve volumes and quoted commodity prices in the futures markets. We then applied appropriate discount rates based on the risk profile of the respective reserve categories. Resulting values from the income approach were compared to ranges of prices paid in the acquisition of similar oil and gas properties in other transactions. Values determined under the income approach were within market ranges.

The fair value of cash and cash equivalents, accounts receivable, accounts payable to vendors and our variable-rate bank debt approximated book value at December 31, 2009 and 2008. As of December 31, 2009 and 2008, the fair value of our \$200,000 8¼% Senior Subordinated Notes due 2011 was \$200,000 and \$145,000, respectively. As of December 31, 2009 and 2008, the fair value of our \$200,000 6¾% Senior Subordinated Notes due 2014 was \$178,000 and \$101,000, respectively. The fair values of our outstanding notes were determined based upon quotes obtained from brokers.

NOTE 8 — ASSET RETIREMENT OBLIGATIONS:

Asset retirement obligations (“ARO”) relate to the removal of facilities and tangible equipment at the end of a property’s useful life. U.S. GAAP requires that the fair value of a liability to retire an asset be recorded on the balance sheet and that the corresponding cost is capitalized in oil and gas properties. The ARO liability is accreted to its future value and the capitalized cost is depreciated consistent with the UOP method. Our estimate of our asset retirement obligations does not give consideration to the value the related assets could have to other parties.

The change in our ARO during 2009, 2008 and 2007 is set forth below:

	Year Ended December 31,		
	2009	2008	2007
Asset retirement obligations as of the beginning of the year, including			
current portion	\$256,855	\$289,790	\$340,376
Liabilities incurred	3,035	2,779	5,279
Liabilities settled	(67,858)	(60,642)	(86,795)
Liabilities assumed.....	-	128,023	-
Divestment of properties	(5,941)	(32,890)	(1,233)
Accretion expense	33,016	17,392	17,620
Revision of estimates	76,429	(87,597)	14,543
Asset retirement obligations as of the end of the year, including current			
portion.....	<u>\$295,536</u>	<u>\$256,855</u>	<u>\$289,790</u>

Due to falling commodity prices and hurricanes, the timing of a substantial portion of our asset retirement obligations was revised in the fourth quarter of 2008 leading to a redetermination of the present value of these obligations. In this redetermination, our credit adjusted risk free interest rate was increased to account for current credit conditions, resulting in a significant downward revision to our asset retirement obligations.

Primarily due to changes in estimated reserve lives, the timing on a substantial portion of our asset retirement obligations was revised in the fourth quarter of 2009 leading to a redetermination of the present value of these obligations. In this redetermination, our credit adjusted risk free rate was decreased to account for current credit conditions contributing to a significant upward revision of our asset retirement obligations.

NOTE 9 — INVENTORY IMPAIRMENT:

For the year ended December 31, 2009, we recorded a write-down of our tubular inventory in the amount of \$9,398. This charge was the result of the market value of these tubulars falling below historical cost.

NOTE 10 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2009	2008
Temporary differences:		
Oil and gas properties – full cost.....	(\$137,797)	(\$252,273)
Hurricane insurance receivable.....	(16,316)	(19,373)
Asset retirement obligations.....	103,438	89,812
Stock compensation	4,296	4,053
Hedges	8,605	(47,198)
Other	7,817	(1,361)
	<u>(\$29,957)</u>	<u>(\$226,340)</u>

We estimate that we have incurred approximately \$30,376 of current federal income tax expense for the year ended December 31, 2009. This is largely due to a reclassification between current and deferred income tax expense related to a proposed IRS audit adjustment with respect to the timing of certain deductions. We have a \$11,110 current income tax payable at December 31, 2009.

Reconciliation between the statutory federal income tax rate and our effective income tax rate as a percentage of income before income taxes follows:

	Year Ended December 31,		
	2009	2008	2007
Income tax expense computed at the statutory federal income tax rate ...	(35.0%)	(35.0%)	35.0%
Domestic production activities deduction	-	-	(1.6)
State taxes and other	0.2	-	(0.5)
Goodwill impairment	-	10.9	-
Statutory depletion	-	(0.1)	-
Effective income tax rate	<u>(34.8%)</u>	<u>(24.2%)</u>	<u>32.9%</u>

In 2009 and 2007, we recognized a tax deduction for domestic production activities pursuant to Internal Revenue Code Section 199.

Income taxes allocated to accumulated other comprehensive income related to oil and gas hedges amounted to (\$54,003), \$51,502 and (\$10,587) for the years ended December 31, 2009, 2008 and 2007, respectively.

As of December 31, 2009 and 2008, we had unrecognized tax benefits of \$25,711 and \$1,178, respectively. If recognized, \$1,178 of our unrecognized tax benefits would impact our effective tax rate. A reconciliation of the total amounts of unrecognized tax benefits follows:

Total unrecognized tax benefits as of December 31, 2008	\$1,178
Increases (decreases) in unrecognized tax benefits as a result of:	
Tax positions taken during a prior period	24,533
Tax positions taken during the current period	-
Settlements with taxing authorities	-
Lapse of applicable statute of limitations	-
Total unrecognized tax benefits as of December 31, 2009	<u>\$25,711</u>

The majority of our unrecognized tax benefits pertain to a proposed IRS audit adjustment with respect to the timing of certain deductions. We believe that our unrecognized tax benefits may be reduced to zero within the next 12 months upon completion and ultimate settlement of the current IRS examinations.

It is our policy to classify interest and penalties associated with underpayment of income taxes as interest expense and general and administrative expenses, respectively. We have recognized \$3,171 and \$54 of interest expense related to uncertain tax positions for the years ended December 31, 2009 and 2008, respectively. We have not recognized any penalties in connection with our uncertain tax positions. The liabilities for unrecognized tax benefits and accrued interest payable are components of other current liabilities on our balance sheet.

The tax years 2005 through 2008 remain subject to examination by major tax jurisdictions.

NOTE 11 — LONG-TERM DEBT:

Long-term debt consisted of the following:

	As of December 31,	
	2009	2008
8¼% Senior Subordinated Notes due 2011	\$200,000	\$200,000
6¾% Senior Subordinated Notes due 2014	200,000	200,000
Bank debt	175,000	425,000
Total long-term debt	<u>\$575,000</u>	<u>\$825,000</u>

On August 28, 2008, we entered into an amended and restated revolving credit facility totaling \$700,000, maturing on July 1, 2011, with a syndicated bank group. At December 31, 2008, our bank credit facility had a borrowing base of \$625,000. On April 29, 2009, the borrowing base was reduced to \$425,000. On October 9, 2009, the borrowing base was reaffirmed at \$425,000 at the semi-annual redetermination. At December 31, 2009, we had \$175,000 of outstanding borrowings under our bank credit facility, letters of credit totaling \$63,145 had been issued under the facility, and the weighted average interest rate under the credit facility was 2.7%. On January 26, 2010, we completed a public offering of \$275,000 aggregate principal amount of 8.625% Senior Notes due 2017. In connection with this offering, we entered into an amendment to our bank credit facility, which provided that if we issued more than \$200,000 of notes, the borrowing base under our bank credit facility would automatically be reduced by an amount equal to 40% of the amount in excess of \$200,000. Upon completion of the offering, our borrowing base was automatically reduced from \$425,000 to \$395,000. As of February 25, 2010, we had \$125,000 of

outstanding borrowings under our bank credit facility, letters of credit totaling \$63,145 had been issued pursuant to the facility, leaving \$206,855 of availability under the facility.

The borrowing base under the credit facility is redetermined semi-annually, in May and November, by the lenders taking into consideration the estimated value of our oil and gas properties and those of our direct and indirect material subsidiaries in accordance with the lenders' customary practices for oil and gas loans. In addition, we and the lenders each have discretion at any time, but not more than two additional times in any calendar year, to have the borrowing base redetermined. If a reduction in our borrowing base were to fall below any outstanding balances under the credit facility plus any outstanding letters of credit, our agreement with the banks allows us one of three options to cure the borrowing base deficiency: (1) repay amounts outstanding sufficient to cure the deficiency within 10 days after our written election to do so; (2) add additional oil and gas properties acceptable to the banks to the borrowing base and take such actions necessary to grant the banks a mortgage in the properties within thirty days after our written election to do so or (3) arrange to pay the deficiency in monthly installments over ninety days or some longer period acceptable to the banks not to exceed six months.

The facility is guaranteed by our subsidiary, Stone Offshore. The credit facility is collateralized by substantially all of Stone's and Stone Offshore's assets. Stone and Stone Offshore are required to mortgage, and grant a security interest in, their oil and gas reserves representing at least 80% of the discounted present value of the future net cash flows from their oil and gas reserves reviewed in determining the borrowing base. At Stone's option, loans under the credit facility will bear interest at a rate based on the adjusted London Interbank Offering Rate plus an applicable margin, or a rate based on the prime rate or Federal funds rate plus an applicable margin.

Under the financial covenants of our credit facility, we must (i) maintain a ratio of consolidated debt to consolidated EBITDA, as defined in the credit agreement, for the preceding four quarterly periods of not greater than 3.25 to 1 and (ii) maintain a ratio of EBITDA to consolidated Net Interest, as defined in the credit agreement, for the preceding four quarterly periods of not less than 3.0 to 1.0. As of December 31, 2009 our debt to EBITDA Ratio was 1.14 to 1 and our EBITDA to consolidated Net Interest Ratio was approximately 24.18 to 1. In addition, the credit facility includes certain customary restrictions or requirements with respect to disposition of properties, incurrence of additional debt, change of ownership and reporting responsibilities. These covenants may limit or prohibit us from paying cash dividends but do allow for limited stock repurchases.

On August 1, 2007, we redeemed our Senior Floating Rate Notes at their face value of \$225,000. The redemption was funded through the proceeds received from the sale of substantially all of our Rocky Mountain Region properties on June 29, 2007. We recorded a pre-tax charge of \$844 in the third quarter of 2007 for the early extinguishment of debt.

On December 15, 2004, we issued \$200,000 6¾% Senior Subordinated Notes due 2014. The notes were sold at par value and we received net proceeds of \$195,500. The notes are subordinated to our senior unsecured credit facility and rank *pari passu* with our 8¼% Senior Subordinated Notes. There is no sinking fund requirement and the notes are redeemable at our option, in whole but not in part, at any time before December 15, 2009 at a Make-Whole Amount. Beginning December 15, 2009, the notes are redeemable at our option, in whole or in part, at 103.375% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2012. The notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. The violation of any of these covenants could give rise to a default, which if not cured could give the holder of the notes a right to accelerate payment. At December 31, 2009, \$563 had been accrued in connection with the June 15, 2010 interest payment.

On December 5, 2001, we issued \$200,000 8¼% Senior Subordinated Notes due 2011. The notes were sold at par value and we received net proceeds of \$195,500. The notes are subordinated to our senior unsecured credit facility and rank *pari passu* with our 6¾% Senior Subordinated Notes. There is no sinking fund requirement and the notes are redeemable at our option, in whole but not in part, at any time before December 15, 2006 at a Make-Whole Amount. Beginning December 15, 2006, the notes are redeemable at our option, in whole or in part, at 104.125% of their principal amount and thereafter at prices declining annually to 100% on and after December 15, 2009. The notes provide for certain covenants, which include, without limitation, restrictions on liens, indebtedness, asset sales, dividend payments and other restricted payments. The violation of any of these covenants could give rise to a default, which if not cured could give the holder of the notes a right to accelerate payment. At December 31, 2009, \$688 had been accrued in connection with the June 15, 2010 interest payment. In January and February 2010, these notes were fully redeemed (see **Note 15 - Subsequent Events**).

On August 28, 2008, we entered into supplemental indentures governing the terms of our 8¼% Senior Subordinated Notes due 2011 and our 6¾% Senior Subordinated Notes due 2014. These notes are now guaranteed by Stone Offshore on an unsecured senior subordinated basis.

Other assets at December 31, 2009 and 2008 included approximately \$9,430 and \$14,035, respectively, of deferred financing costs, net of accumulated amortization. These costs at December 31, 2009 related primarily to the issuance of the 8¼% notes, the 6¾% notes and the new bank credit facility. The costs associated with the 8¼% notes and the 6¾% notes are being amortized over the life of the notes using a method that applies effective interest rates of 8.6% and 7.1%, respectively. The costs associated with the credit facility are being amortized over the term of the facility.

Total interest cost incurred on all obligations for the years ended December 31, 2009, 2008 and 2007 was \$46,934, \$39,598 and \$48,253 respectively.

NOTE 12 — STOCK-BASED COMPENSATION:

We record stock compensation expense under U.S. GAAP for all unvested stock options and other equity-based compensation. We adopted these provisions using the modified prospective method effective January 1, 2006. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, has been or will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant, has been or will be recognized in our financial statements over the vesting period.

For the year ended December 31, 2009, we incurred \$8,845 of stock based compensation, of which \$7,624 related to restricted stock issuances, \$1,221 related to stock option grants and of which a total of approximately \$2,901 was capitalized into oil and gas properties. For the year ended December 31, 2008, we incurred \$13,086 of stock based compensation, of which \$10,334 related to restricted stock issuances, \$2,572 related to stock option grants and \$180 related to employee bonus stock awards and of which a total of approximately \$4,681 was capitalized into oil and gas properties. For the year ended December 31, 2007, we incurred \$8,775 of stock based compensation, of which \$6,177 related to restricted stock issuances and \$2,598 related to stock option grants and of which a total of approximately \$3,380 was capitalized into oil and gas properties. Because of the non-cash nature of stock based compensation, the expensed portion of stock based compensation is added back to the net income (loss) in arriving at net cash provided by operating activities in our statement of cash flows. The capitalized portion is not included in net cash used in investing activities.

Under our 2009 Amended and Restated Stock Incentive Plan (the “2009 Plan”), we may grant both incentive stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options to all employees and directors. All such options must have an exercise price of not less than the fair market value of the common stock on the date of grant and may not be re-priced without stockholder approval. Stock options to all employees vest ratably over a five-year service-vesting period and expire ten years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire ten years subsequent to award. In addition, the 2009 Plan provides that shares available under the 2009 Plan may be granted as restricted stock. Restricted stock typically vests over a three-year period.

Stock Options. Stock options granted and related fair values for the years ended December 31, 2009, 2008 and 2007 are listed in the following table. The fair value was determined using the Black-Scholes option pricing model with the following assumptions:

	Year Ended December 31,		
	2009	2008	2007
	(Amounts in table represent actual values except where indicated otherwise)		
Stock options granted	64,474	40,000	25,000
Fair value of stock options granted (\$ in thousands)	\$321	\$980	\$342
Weighted average grant date fair value	\$4.98	\$24.51	\$13.66
Assumptions:			
Dividend yield	0.00%	0.00%	0.00%
Expected volatility	44.66%	37.70%	33.01%
Risk-free rate	2.39%	3.65%	4.60%
Expected option life	10.0 years	10.0 years	6.0 years
Forfeiture rate	0.00%	0.00%	0.00%

Expected volatility and expected option life are based on a historical average. The risk-free rate is based on quoted rates on zero-coupon Treasury Securities for terms consistent with the expected option life.

A summary of stock option activity under the Plan during the year ended December 31, 2009 is as follows (amounts in table represent actual values except where indicated otherwise):

	<u>Number of Options</u>	<u>Wgtd. Avg. Exercise Price</u>	<u>Wgtd. Avg. Term</u>	<u>Aggregate Intrinsic Value (in thousands)</u>
Options outstanding, beginning of period	510,779	\$45.21		
Granted.....	64,474	8.64		
Exercised.....	-	-		\$ -
Forfeited.....	(14,470)	33.59		
Expired.....	<u>(65,500)</u>	54.15		
Options outstanding, end of period	<u>495,283</u>	39.61	4.7 years	607
Options exercisable, end of period.....	<u>363,709</u>	44.40	4.1 years	-
Options unvested, end of period.....	<u>131,574</u>	26.37	7.3 years	607

Exercise prices for stock options outstanding at December 31, 2009 range from \$6.97 to \$61.58.

A summary of stock option activity under the Plan during the year ended December 31, 2008 is as follows (amounts in table represent actual values except where indicated otherwise):

	<u>Number of Options</u>	<u>Wgtd. Avg. Exercise Price</u>	<u>Wgtd. Avg. Term</u>	<u>Aggregate Intrinsic Value (in thousands)</u>
Options outstanding, beginning of period	931,589	\$43.72		
Granted.....	40,000	44.67		
Exercised.....	(447,330)	41.84		\$9,514
Forfeited.....	(13,480)	54.74		
Expired.....	-	-		
Options outstanding, end of period	<u>510,779</u>	45.21	5.0 years	-
Options exercisable, end of period.....	<u>382,679</u>	45.34	4.3 years	-
Options unvested, end of period.....	<u>128,100</u>	44.83	7.2 years	-

A summary of stock option activity under the Plan during the year ended December 31, 2007 is as follows (amounts in table represent actual values except where indicated otherwise):

	<u>Number of Options</u>	<u>Wgtd. Avg. Exercise Price</u>	<u>Wgtd. Avg. Term</u>	<u>Aggregate Intrinsic Value (in thousands)</u>
Options outstanding, beginning of period	1,394,835	\$42.87		
Granted.....	25,000	33.19		
Exercised.....	(127,636)	33.29		\$707
Forfeited.....	(52,490)	37.42		
Expired.....	<u>(308,120)</u>	44.40		
Options outstanding, end of period	<u>931,589</u>	43.72	4.7 years	5,254
Options exercisable, end of period.....	<u>736,659</u>	43.74	4.1 years	4,475
Options unvested, end of period.....	<u>194,930</u>	43.64	7.0 years	779

Restricted Stock. The fair value of restricted shares is determined based on the average of the high and low prices on the issuance date and assumes a 5% forfeiture rate in 2009, 2008 and 2007. During the year ended December 31, 2009, we issued 538,635 shares of restricted stock valued at \$5,831. During the year ended December 31, 2008, we issued 278,646 shares of restricted stock valued at \$13,352. During the year ended December 31, 2007, we issued 193,084 shares of restricted stock valued at \$6,576.

A summary of the restricted stock activity under the Plan for the years ended December 31, 2009, 2008 and 2007 is as follows (amounts in table represent actual values):

	2009		2008		2007	
	Number of Restricted Shares	Wgt'd. Avg. Fair Value Per Share	Number of Restricted Shares	Wgt'd. Avg. Fair Value Per Share	Number of Restricted Shares	Wgt'd. Avg. Fair Value Per Share
Restricted stock outstanding, beginning of period.....	408,383	\$43.31	311,486	\$39.86	328,447	\$46.97
Issuances.....	538,635	10.83	278,646	47.92	193,084	34.06
Lapse of restrictions.....	(177,123)	41.73	(167,818)	44.62	(114,740)	48.01
Forfeitures.....	(18,458)	26.74	(13,931)	44.99	(95,305)	42.74
Restricted stock outstanding, end of period.....	<u>751,437</u>	<u>\$20.68</u>	<u>408,383</u>	<u>\$43.31</u>	<u>311,486</u>	<u>\$39.86</u>

As of December 31, 2009, there was \$8,864 of unrecognized compensation cost related to all non-vested share-based compensation arrangements under the Plan. That cost is being amortized on a straight-line basis over the vesting period and is expected to be recognized over a weighted-average period of 1.7 years. Subsequent to December 31, 2009, 285,757 shares of restricted stock were granted under the Plan.

Under U.S. GAAP, if tax deductions exceed book compensation expense, then excess tax benefits are credited to additional paid-in capital to the extent realized. If book compensation expense exceeds tax deductions, the tax deficit results in either a reduction in additional paid-in capital or an increase in income tax expense depending on certain circumstances. Credits to additional paid-in capital for net tax benefits were (\$1,648), \$2,740 and \$458 in 2009, 2008 and 2007, respectively.

NOTE 13 — DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES:

Our hedging strategy is designed to protect our near and intermediate term cash flow from future declines in oil and natural gas prices. This protection is essential to capital budget planning which is sensitive to expenditures that must be committed to in advance such as rig contracts and the purchase of tubular goods. We enter into hedging transactions to secure a commodity price for a portion of future production that is acceptable at the time of the transaction. These hedges are designated as cash flow hedges upon entering into the contract. We do not enter into hedging transactions for trading purposes. We have no fair value hedges.

The nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. If the instrument qualifies for hedge accounting treatment, it is recorded as either an asset or liability measured at fair value and subsequent changes in the derivative's fair value are recognized in equity through other comprehensive income (loss), net of related taxes, to the extent the hedge is considered effective. Additionally, monthly settlements of effective hedges are reflected in revenue from oil and gas production and cash flows from operations. Instruments not qualifying for hedge accounting are recorded in the balance sheet at fair value and changes in fair value are recognized in earnings through derivative expense (income). Typically, a small portion of our derivative contracts are determined to be ineffective. This is because oil and natural gas price changes in the markets in which we sell our products are not 100% correlative to changes in the underlying price basis indicative in the derivative contract. Monthly settlements of ineffective hedges are recognized in earnings through derivative expense (income) and cash flows from operations.

We have entered into fixed-price swaps with various counterparties for a portion of our expected 2010 and 2011 oil and natural gas production from the Gulf Coast Basin. A portion of our 2009 production was hedged with fixed-price swaps. Some of our fixed-price gas swap settlements are based on an average of New York Mercantile Exchange ("NYMEX") prices for the last three days of a respective month and some are based on the NYMEX price for the last day of a respective month. The fixed-price oil swap settlements are based upon an average of the NYMEX closing price for West Texas Intermediate ("WTI") during the entire calendar month. Swaps typically provide for monthly payments by us if prices rise above the swap price or to us if prices fall below the swap price. Our outstanding fixed-price swap contracts are with J.P. Morgan Chase Bank, N.A., The Toronto-Dominion Bank, Barclays Bank PLC, BNP Paribas and The Bank of Nova Scotia.

During 2009, 2008 and 2007, a portion of our oil and natural gas production was hedged with zero-premium collars. The natural gas collar settlements are based on an average of NYMEX prices for the last three days of a respective month. The oil collar settlements are based on an average of the NYMEX closing price for WTI during the entire calendar month. The collar contracts require payments to the counterparties if the average price is above the ceiling price or payment from the counterparties if the average price is below the floor price.

During 2008, a portion of our natural gas production was also hedged with put contracts. Put contracts are purchased at a rate per unit of hedged production that fluctuates with the commodity futures market. The historical cost of the put contracts represents our maximum cash exposure. We are not obligated to make any further payments under the put contracts regardless of future commodity price fluctuations. Under put contracts, monthly payments are made to us if NYMEX prices fall below the agreed upon floor price, while allowing us to fully participate in commodity prices above the floor.

During the years ended December 31, 2009, 2008 and 2007, certain of our derivative contracts were determined to be partially ineffective because of differences in the relationship between the fixed price in the derivative contract and actual prices realized. During the second half of 2008, as a result of extended shut-ins of production after Hurricanes Gustav and Ike, our September 2008 crude oil and natural gas production levels were below the volumes that we had hedged. Consequently, some of our crude oil and natural gas hedges for September 2008 were deemed to be ineffective.

All of our derivative instruments at December 31, 2009 and December 31, 2008 were designated as hedging instruments. The following tables disclose the location and fair value amounts of derivative instruments reported in our balance sheet at December 31, 2009 and December 31, 2008.

Fair Value of Derivative Instruments at December 31, 2009

(in thousands)

Description	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity contracts	Current assets: Fair value of hedging contracts	\$16,223	Current liabilities: Fair value of hedging contracts	(\$34,859)
	Long-term assets: Fair value of hedging contracts	1,771	Long-term liabilities: Fair value of hedging contracts	(7,721)
		<u>\$17,994</u>		<u>(\$42,580)</u>

Fair Value of Derivative Instruments at December 31, 2008

(in thousands)

Description	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity contracts	Current assets: Fair value of hedging contracts	\$136,072	Long-term liabilities: Fair value of hedging contracts	(\$1,221)
		<u>\$136,072</u>		<u>(\$1,221)</u>

The following table discloses the effect of derivative instruments in the statement of operations for the years ended December 31, 2009, 2008 and 2007.

The Effect of Derivative Instruments on the Statement of Operations for the Years Ended December 31, 2009, 2008 and 2007

(in thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in OCI on Derivative	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) (a)	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)
	<u>Location</u>		<u>Location</u>
	<u>2009</u>	<u>2009</u>	<u>2009</u>
Commodity contracts	(\$100,292)	Operating revenue - oil/gas production \$163,176	Derivative income (expense), net \$3,061
Total	<u>(\$100,292)</u>	<u>\$163,176</u>	<u>\$3,061</u>
	<u>2008</u>	<u>2008</u>	<u>2008</u>
Commodity contracts	\$95,647	Operating revenue - oil/gas production (\$19,162)	Derivative income (expense), net \$3,327
Total	<u>\$95,647</u>	<u>(\$19,162)</u>	<u>\$3,327</u>
	<u>2007</u>	<u>2007</u>	<u>2007</u>
Commodity contracts	(\$19,584)	Operating revenue - oil/gas production \$7,884	Derivative income (expense), net (\$666)
Total	<u>(\$19,584)</u>	<u>\$7,884</u>	<u>(\$666)</u>

- (a) For the year ended December 31, 2009, effective hedging contracts increased oil revenue by \$61,747 and increased gas revenue by \$101,429. For the year ended December 31, 2008, effective hedging contracts decreased oil revenue by \$34,435 and increased gas revenue by \$15,273. For the year ended December 31, 2007, effective hedging contracts decreased oil revenue by \$2,554 and increased gas revenue by \$10,438.

On March 3, 2009, we unwound all of our then existing crude oil hedges for the period from April 2009 through December 2009, resulting in proceeds of approximately \$59,007. On March 6, 2009, we unwound two of our natural gas hedges for the period from April 2009 through December 2009, resulting in proceeds of approximately \$53,814. These amounts (net of the ineffective portion and related deferred income tax effect) were recorded in accumulated other comprehensive income. As the original time periods for these contracts expired, applicable amounts were reclassified into earnings.

At December 31, 2009, we had an accumulated other comprehensive loss of \$15,380, net of tax, which related to the fair value of our 2010 and 2011 swap contracts. We believe that approximately \$11,656 of the accumulated other comprehensive loss will be reclassified into earnings in the next twelve months.

The following table illustrates our hedging positions for calendar years 2010 and 2011 as of February 25, 2010:

	Fixed-Price Swaps			
	Natural Gas		Oil	
	Daily Volume (MMBtus/d)	Swap Price	Daily Volume (Bbls/d)	Swap Price
2010	20,000	\$6.97	2,000	\$63.00
2010	20,000	6.50	1,000	64.05
2010	10,000	6.50	1,000	60.20
2010			1,000	75.00
2010			1,000	75.25
2010			4,000 (a)	73.65
2010			2,000 (b)	80.10
2011	10,000	6.83	1,000	70.05
2011			1,000	78.20
2011			1,000	83.00
2011			1,000	83.05

(a) January - March

(b) April - December

NOTE 14 — SHARE REPURCHASE PROGRAM:

On September 24, 2007, our Board of Directors authorized a share repurchase program for an aggregate amount of up to \$100,000. The shares may be repurchased from time to time in the open market or through privately negotiated transactions. The repurchase program is subject to business and market conditions, and may be suspended or discontinued at any time. Through December 31, 2009, 300,000 shares had been repurchased under this program at a total cost of \$7,071.

NOTE 15 — SUBSEQUENT EVENTS:

We evaluated subsequent events through February 25, 2010, which represents the date our financial statements were issued for the year ended December 31, 2009.

On January 26, 2010, we completed a public offering of \$275,000 aggregate principal amount of 8.625% Senior Notes due 2017. In connection with this offering, we entered into an amendment to our bank credit facility, which provided that if we issued more than \$200,000 of notes, the borrowing base under our bank credit facility would automatically be reduced by an amount equal to 40% of the amount in excess of \$200,000. Upon completion of the offering, our borrowing base was automatically reduced from \$425,000 to \$395,000. The net proceeds from the offering after deducting underwriting discounts, commissions, estimated fees and expenses totaled \$265,961.

In January 2010 we used the proceeds from the 8.625% Senior Notes offering to purchase our 8-1/4% Senior Subordinated Notes due 2011 pursuant to a tender offer and consent solicitation. In February 2010, the remaining 8-1/4% Senior Subordinated Notes were redeemed in full. The total cost of the redemption was \$202,382 which included \$200,483 to redeem the notes plus accrued and unpaid interest of \$1,899. The transaction will result in an after-tax charge to earnings of approximately \$1,169 in 2010.

In January 2010, we acquired an approximate 10,000 net acre leasehold position in Appalachia at a cost of approximately \$18,000.

NOTE 16 — COMMITMENTS AND CONTINGENCIES:

We lease office facilities in Houston, Texas and Morgantown, West Virginia under the terms of long-term, non-cancelable leases expiring on various dates through 2012. We also lease certain equipment on our oil and gas properties typically on a month-to-month basis. The minimum net annual commitments under all leases, subleases and contracts noted above at December 31, 2009 were as follows:

2010	\$473
2011	193
2012	59

Payments related to our lease obligations for the years ended December 31, 2009, 2008 and 2007 were approximately \$738, \$489 and \$530 respectively.

We are contingently liable to surety insurance companies in the amount of \$59,812 relative to bonds issued on our behalf to the United States Department of the Interior Minerals Management Service (“MMS”), federal and state agencies and certain third parties from which we purchased oil and gas working interests. The bonds represent guarantees by the surety insurance companies that we will operate in accordance with applicable rules and regulations and perform certain plugging and abandonment obligations as specified by applicable working interest purchase and sale agreements.

We are also named as a defendant in certain lawsuits and are a party to certain regulatory proceedings arising in the ordinary course of business. We do not expect these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

In connection with our exploration and development efforts, we are contractually committed to the use of drilling rigs and the acquisition of seismic data in the aggregate amount of \$28,556 to be incurred over the next year.

OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. Under OPA and a final rule adopted by the MMS in August 1998, responsible parties of covered offshore facilities that have a worst case oil spill of more than 1,000 barrels must demonstrate financial responsibility in amounts ranging from at least \$10,000 in specified state waters to at least \$35,000 in OCS waters, with higher amounts of up to \$150,000 in certain limited circumstances where the MMS believes such a level is justified by the risks posed by the operations, or if the worst case oil-spill discharge volume possible at the facility may exceed the applicable threshold volumes specified under the MMS’s final rule. We do not anticipate that we will experience any difficulty in continuing to satisfy the MMS’s requirements for demonstrating financial responsibility under OPA and the MMS’s regulations.

Franchise Tax Action. We have been served with several petitions filed by the Louisiana Department of Revenue (“LDR”) in Louisiana state court claiming additional franchise taxes due of approximately \$9,014 plus accrued interest of approximately \$4,211. These assessments all relate to the LDR’s assertion that sales of crude oil and natural gas from properties located on the Outer Continental Shelf, which are transported through the state of Louisiana, should be sourced to the state of Louisiana for purposes of computing the Louisiana franchise tax apportionment ratio. The claims relate to franchise tax years from 1999 through 2006. The Company disagrees with these contentions and intends to vigorously defend itself against these claims. The franchise tax years 2007 through 2009 for Stone and franchise tax years 2006 through 2008 for Bois d’Arc remain subject to examination, which potentially exposes us to additional estimated assessments of \$8,092 plus interest of \$4,597.

Federal Securities Action. A consolidated putative class action is pending in the United States District Court for the Western District of Louisiana (the “Federal Court”) against Stone, David Welch, Kenneth Beer, D. Peter Canty and James Prince purporting to allege violations of Sections 10(b) and 20(a) of the Securities Exchange Act of 1934 (“Securities Action”). The consolidated complaint alleges a putative class period to commence on May 2, 2001 and to end on March 10, 2006 and contends that, during the putative class period, defendants, among other things, misstated or failed to disclose (i) that Stone had materially overstated Stone’s financial results by overvaluing its oil reserves through improper and aggressive reserve methodologies; (ii) that the Company lacked adequate internal controls and was therefore unable to ascertain its true financial condition; and (iii) that as a result of the foregoing, the values of the Company’s proved reserves, assets and future net cash flows were materially overstated at all relevant times.

On October 1, 2007, the Federal Court ordered that (i) the claims asserted against defendants Kenneth Beer and James Prince pursuant to Section 10(b) of the Securities Exchange Act and Rule 10b-5 promulgated thereunder and (ii) claims asserted on behalf of putative class members who sold their Company shares prior to October 6, 2005 be dismissed. The remaining claims are still pending.

On or about May 12, 2008, then Lead Plaintiff El Paso Fireman & Policeman’s Pension Fund filed a motion to certify the Securities Action as a class action (“Class Certification Motion”). Defendants filed an opposition to the Class Certification Motion on June 27, 2008. Defendants also filed a Motion for Judgment on the Pleadings and a related Motion to Amend Answer to the Consolidated Class Action Complaint on or about June 11, 2008. In a memorandum ruling filed on February 27,

2009, the Court held that El Paso Fireman & Policeman's Pension Fund did not have capacity to sue or be sued and dismissed it from the lawsuit. Subsequently, the Court denied the Class Certification Motion as moot.

On September 30, 2009, the City of Knoxville Employees' Pension Board ("Knoxville") was appointed as the new lead plaintiff. On October 30, 2009, Knoxville filed a new motion for class certification. On November 25, 2009, all parties advised the Court that they had reached a settlement in principle of all claims in the Securities Action. Because the Securities Action was brought as a putative class action, the proposed settlement is subject to Court approval under Rule 23 of the Federal Rules of Civil Procedure. Knoxville filed on January 11, 2010 a motion for preliminary approval of the settlement, which included as an exhibit a stipulation of settlement signed by counsel for all parties. The stipulation of settlement sets forth all material terms of the settlement, including the settlement payment amount of \$10,500 and the complete release of all claims against all defendants in the Securities Action. The settlement payment is being made under the Company's directors and officers liability insurance policy.

The Court issued an order on January 14, 2010 preliminarily approving the settlement (the "January 24, 2010 Order"). The Court has set a Settlement Fairness Hearing to be held on March 23, 2010 in Lafayette, Louisiana. The Court's January 14, 2010 Order sets forth the procedures that must be followed within 120 days of the notice of settlement (which occurred on or about January 22, 2010) by any shareholder that would like to be considered for a distribution of the \$10,500 settlement payment. The January 14, 2010 Order also sets forth the procedures for making objections to the proposed settlement and for seeking exclusion from (or "opting out" of) the binding settlement, both of which the Court has ordered must be done no later than fourteen (14) days before the Settlement Fairness Hearing.

Derivative Actions. In addition, pending in the Federal Court and in the 15th Judicial District Court, Parish of Lafayette, Louisiana (the "State Court") are actions purportedly alleging claims derivatively on behalf of Stone. The operative complaints in these derivative actions name Stone as a nominal defendant and David Welch, Kenneth Beer, D. Peter Canty, James Prince, James Stone, John Laborde, Peter Barker, George Christmas, Richard Pattarozzi, David Voelker, Raymond Gary, B.J. Duplantis and Robert Bernhard as defendants. (These actions are collectively referred to as the "Derivative Actions.") The State Court action purports to allege claims of breach of fiduciary duty, abuse of control, gross mismanagement, and waste of corporate assets against all defendants, and claims of unjust enrichment and insider selling against certain individual defendants. The Federal Court derivative action purports to assert claims against all defendants for breach of fiduciary duty, abuse of control, gross mismanagement, waste of corporate assets and unjust enrichment and claims against certain individual defendants for breach of fiduciary duty and violations of the Sarbanes-Oxley Act of 2002. The Federal Court action has been stayed since December 21, 2006.

On February 16, 2010, a stipulation of settlement signed by counsel for all parties to the Derivative Action was filed with the Federal Court. The material terms of the settlement are set forth in detail in this stipulation. The terms include (i) a monetary payment of \$300 for attorneys' fees and expenses, and (ii) the continuation of certain corporate governance measures respecting (1) the procedures to be followed by the Company's Reserves Committee, (2) the maintenance of a anonymous reporting policy, and (3) the maintenance of an anonymous third party hotline. The Company anticipates that the \$300 payment will be made under the Company's directors and officers liability insurance policy. This proposed settlement is also subject to Federal Court approval under Rule 23.1 of the Federal Rules of Civil Procedure. On February 18, 2010, the Federal Court entered an order preliminarily approving this proposed settlement ("February 18, 2010 Order"). The February 18, 2010 Order set a Settlement Hearing for March 23, 2010 at 1:30 p.m. to consider the propriety of finally approving the proposed settlement and awarding attorneys' fees. The February 18, 2010 Order also sets forth the procedures and deadlines for any shareholder to object to the settlement, which must be done no later than ten (10) calendar days prior to the Settlement Hearing.

Ad Valorem Tax Suit. In August 2009, Gene P. Bonvillain, in his capacity as Assessor for the Parish of Terrebonne, State of Louisiana, filed civil action No. 90-03540 and other consolidated cases in the United States District Court for the Eastern District of Louisiana against approximately thirty oil and gas companies, including Stone, and their respective chief executive officers for allegedly unpaid ad valorem taxes. The amount alleged to be due by Stone for the years 1998 through 2008 is \$11,300. The defendants were subsequently served and have filed motions to dismiss this litigation pursuant to Rule 12(b)(6) of the Federal Rules of Civil Procedure. The Company believes that the assessor is in error in his allegations, and the Company intends to vigorously defend this action.

The foregoing pending actions are at an early stage, and we cannot currently predict the manner and timing of the resolution of these matters and are unable to estimate a range of possible losses or any minimum loss from such matters.

Stone's Certificate of Incorporation and/or its Restated Bylaws provide, to the extent permissible under the law of the State of Delaware (Stone's state of incorporation), for indemnification of and advancement of defense costs to Stone's current and former directors and officers for potential liabilities related to their service to Stone. Stone has purchased directors and officers insurance policies that, under certain circumstances, may provide coverage to Stone and/or its officers and directors for certain losses resulting from securities-related civil liabilities and/or the satisfaction of indemnification and advancement obligations owed to directors and officers. These insurance policies may not cover all costs and liabilities incurred by Stone and its current and former officers and directors in these regulatory and civil proceedings.

NOTE 17 — EMPLOYEE BENEFIT PLANS:

We have entered into deferred compensation and disability agreements with certain of our officers and former officers whereby we have purchased split-dollar life insurance policies to provide certain retirement and death benefits for certain of our officers and former officers and death benefits payable to us. The aggregate death benefit of the policies was \$449 at December 31, 2009, of which \$325 was payable to an officer or his beneficiaries and \$124 was payable to us. Total cash surrender value of the policies, net of related surrender charges at December 31, 2009, was approximately \$28 and is recorded in other assets. Additionally, the benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2009, the liability for such vested benefits was approximately \$904 and is recorded in other long-term liabilities.

The following is a brief description of each incentive compensation plan applicable to our employees:

- i. The Amended and Restated Revised Annual Incentive Compensation Plan, which was adopted in November 2007, provides for annual cash incentive bonuses that are tied to the achievement of certain strategic objectives as defined by our board of directors on an annual basis. Stone incurred expenses of \$6,402, \$2,315, and \$5,117, net of amounts capitalized, for each of the years ended December 31, 2009, 2008 and 2007, respectively, related to incentive compensation bonuses to be paid under the revised plan.
- ii. At the 2009 Annual Meeting of Stockholders, the stockholders approved the 2009 Amended and Restated Stock Incentive Plan (the “2009 Plan”). The 2009 Plan is an amendment and restatement of the company’s 2004 Amended and Restated Stock Incentive Plan (the “2004 Plan”) and it supersedes and replaces in its entirety the 2004 Plan. The 2009 Plan provides for the granting of incentive stock options and restricted stock awards or any combination as is best suited to the circumstances of the particular employee or nonemployee director. The number of shares subject to the 2009 Plan was increased by 1,500,000 shares from the 4,225,000 shares of common stock to be reserved for issuance pursuant to the 2004 plan. The 2009 Plan eliminates the automatic grant of stock options or restricted stock awards to Nonemployee Directors that was provided for in the 2004 Plan so that awards under the 2009 Plan are entirely at the discretion of the Board of Directors. Under the 2009 Plan, we may grant both incentive stock options qualifying under Section 422 of the Internal Revenue Code and options that are not qualified as incentive stock options to all employees and directors. All such options must have an exercise price of not less than the fair market value of the common stock on the date of grant and may not be re-priced without stockholder approval. Stock options to all employees vest ratably over a five-year service-vesting period and expire ten years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire ten years subsequent to award. In addition, the 2009 Plan provides that shares available under the 2009 Plan may be granted as restricted stock. Restricted stock grants typically vest in two or more years at the discretion of the Compensation Committee of the board of directors. At December 31, 2009, we had approximately 1,383,755 additional shares available for issuance pursuant to the Plan.
- iii. The Stone Energy 401(k) Profit Sharing Plan provides eligible employees with the option to defer receipt of a portion of their compensation and we may, at our discretion, match a portion or all of the employee's deferral. The amounts held under the plan are invested in various investment funds maintained by a third party in accordance with the directions of each employee. An employee is 20% vested in matching contributions (if any) for each year of service and is fully vested upon five years of service. For the years ended December 31, 2009, 2008 and 2007, Stone contributed \$1,161, \$1,119 and \$870, respectively, to the plan.
- iv. The Stone Energy Corporation Deferred Compensation Plan provides eligible executives with the option to defer up to 100% of their compensation for a calendar year and we may, at our discretion, match a portion or all of the participant’s deferral based upon a percentage determined by the board of directors. To date there have been no matching contributions made by Stone. The amounts held under the plan are invested in various investment funds maintained by a third party in accordance with the direction of each participant. At December 31, 2009 and 2008, plan assets of \$5,149 and \$4,052, respectively, were included in other assets. An equal amount of plan liabilities were included in other long-term liabilities.

- v. On April 7, 2009, we amended and restated our Executive Change of Control and Severance Plan effective as of December 31, 2008 (as so amended and restated, the “Executive Plan”). The amended and restated Executive Plan also replaced and superseded our Executive Change in Control and Severance Policy that was maintained for certain designated executives (specifically, the CEO and CFO). The Executive Plan will provide the company’s officers that are terminated in the event of a change of control and upon certain other terminations of employment with change of control and severance benefits as defined in the Executive Plan. Executives who are terminated within the scope of the Executive Plan will be entitled to certain payments and benefits including the following: a base salary up to the date of termination; in the case of the CEO and CFO, a lump sum severance payment of 2.99 times the sum of his annual pay and any target bonus at the one hundred percent level; a lump sum amount representing a pro rata share of the bonus opportunity up to the date of termination at the then projected rate of payout; in the case of officers other than the CEO and CFO and an involuntary termination occurring outside a change of control period, a lump sum severance payment in an amount equal to the executive’s annual base salary; in the case of officers other than the CEO and CFO and an involuntary termination occurring during a change of control period, a lump sum severance payment in an amount equal to 2.99 times the executive’s annual base salary; continued health plan coverage for six months and outplacement services. In the case of the CEO and CFO, if the payments would be “excess parachute payments,” they will be reduced as necessary to avoid the 20% excise tax under Section 4999 of the Internal Revenue Code (the “Code”) but only if the executive is in a better net after-tax position after such reduction. Also, if a payment would be to a “key employee” for purposes of Section 409A of the Code, payment will be delayed until six months after his termination if required to comply with Section 409A. Benefits paid upon a change of control, without regard to whether there is a termination of employment, include the following: lapse of restrictions on restricted stock, accelerated vesting and cash-out of all in-the-money stock options, a 401(k) plan employer matching contribution at the rate of 50%, and a pro-rated portion of the projected bonus, if any, for the year of change of control.

On December 7, 2007, our board of directors approved and adopted the Stone Energy Corporation Employee Change of Control Severance Plan (“Employee Severance Plan”), as amended and restated to comply with the final regulations under Section 409A of the Internal Revenue Code and to provide that said plan will remain in force and effect unless and until terminated by the board. The Employee Severance Plan amended and restated the company’s previous Employee Change of Control Severance Plan dated November 16, 2006. The Employee Severance Plan covers all full-time employees other than officers. Severance is triggered by an involuntary termination of employment on and during the 6 month period following a change of control, including a resignation by the employee relating to a change in duties. Employees who are terminated within the scope of the Employee Severance Plan will be entitled to certain payments and benefits including the following: a lump sum equal to (1) his weekly pay times his full years of service, plus (2) one week’s pay for each full \$10,000 of annual pay, but the sum of (1) and (2) cannot be less than 12 weeks of pay or greater than 52 weeks of pay; continued health plan coverage for six months; and a pro-rated portion of the employee’s targeted bonus for the year. Benefits paid upon a change of control, without regard to whether there is a termination of employment, include the following: lapse of restrictions on restricted stock, accelerated vesting and cash-out of all in-the-money stock options, a 401(k) plan employer matching contribution at the rate of 50%, and a lump sum cash payment equal to the product of (i) the number of “restricted shares” of company stock that the employee would have received under the company’s stock plan but did not receive for the time-vested portion of his long-term stock incentive award, if any, for the calendar year in which the change of control occurs times (ii) the price per share of the company’s common stock utilized in effecting the change of control, provided that such amount shall be prorated by multiplying such amount by the number of full months that have elapsed from January 1 of that calendar year to the effective date of the change of control and then dividing the result by twelve (12).

NOTE 18 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our estimated net proved oil and gas reserves at December 31, 2009 have been prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates. In December 2008, the SEC issued a final rule, “Modernization of Oil and Gas Reporting,” which adopts revisions to the SEC’s oil and gas reporting requirements. Among other things, the revisions: (1) replace the single-day year-end pricing with a twelve-month average pricing assumption; (2) permit the reporting of probable and possible reserves in addition to the existing requirement to disclose proved reserves; (3) allow the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes; (4) require the disclosure of the independence and qualifications of third party preparers of reserves; and (5) require the filing of reports when a third party is relied upon to prepare or audit reserve estimates. We were required to adopt the provisions of the new rule as of December 31, 2009 for this 2009 Annual Report on Form 10-K. In January 2010, the FASB issued its final standard on oil and gas reserves estimation and disclosures aligning its requirements with the SEC’s final rule. The new rules are considered a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision. Application of the new rules resulted in lower prices at December 31, 2009 for both oil and natural gas than would have resulted under the previous rules. The impact of the new price methodology was to decrease oil reserves by 2.2 million barrels, decrease natural gas reserves by 40.2 Bcf and decrease the standardized measure by an estimated \$488,000. There were no other material changes to reserves resulting from the new rules.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in providing the future rates of production and timing of development expenditures. The following reserve data represents estimates only and should not be construed as being exact. In addition, the present values should not be construed as the market value of the oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

The following table sets forth an analysis of the estimated quantities of net proved and proved developed oil (including condensate) and natural gas reserves, all of which are located onshore and offshore the continental United States. Estimated proved oil and natural gas reserves at December 31, 2009 are prepared in accordance with the SEC's new rule, "Modernization of Oil and Gas Reporting".

	Oil (MBbls)	Natural Gas (MMcf)	Oil and Natural Gas (MMcfe)
Estimated proved reserves as of December 31, 2006	41,360	342,782	590,942
Revisions of previous estimates	4,584	27,183	54,688
Extensions, discoveries and other additions	1,635	20,765	30,573
Sale of reserves	(9,905)	(132,559)	(191,988)
Production	(6,088)	(45,088)	(81,617)
Estimated proved reserves as of December 31, 2007	31,586	213,083	402,598
Revisions of previous estimates	(4,416)	(37,509)	(64,007)
Extensions, discoveries and other additions	625	6,246	9,996
Purchase of producing properties	14,680	164,408	252,489
Sale of reserves	(995)	(12,265)	(18,238)
Production	(4,916)	(34,409)	(63,903)
Estimated proved reserves as of December 31, 2008	36,564	299,554	518,935
Revisions of previous estimates	1,964	(53,423)	(41,636)
Extensions, discoveries and other additions	417	12,198	14,703
Sale of reserves	(402)	(300)	(2,714)
Production	(6,207)	(41,335)	(78,577)
Estimated proved reserves as of December 31, 2009	<u>32,336</u>	<u>216,694</u>	<u>410,711</u>
Estimated proved developed reserves:			
as of December 31, 2007	<u>25,172</u>	<u>171,815</u>	<u>322,846</u>
as of December 31, 2008	<u>28,410</u>	<u>227,857</u>	<u>398,317</u>
as of December 31, 2009	<u>24,380</u>	<u>172,452</u>	<u>318,729</u>

The following tables present the standardized measure of future net cash flows related to estimated proved oil and gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2009. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the tables below, represent the fair value of our estimated oil and gas reserves. Prior to December 31, 2009, we were required to determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. Effective December 31, 2009, the SEC issued a final rule which changed prices used in reserves calculations. Prices will no longer be based on a single-day, period-end price. Rather, they will be based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. The 2009 average 12-month oil and gas prices net of differentials were \$58.95 per barrel of oil and \$3.49 per Mcf of gas. The average 2008 year-end oil and gas prices net of differentials were \$39.70 per barrel of oil and \$5.87 per Mcf of gas. The average 2007 year-end oil and gas prices net of differentials were \$94.72 per barrel of oil and \$7.25 per Mcf of gas. Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

	Standardized Measure Year Ended December 31,		
	2009	2008	2007
Future cash inflows	\$2,663,285	\$3,210,283	\$4,538,017
Future production costs	(950,434)	(1,131,548)	(915,166)
Future development costs	(912,500)	(1,153,950)	(842,040)
Future income taxes	(38,845)	(8,989)	(734,139)
Future net cash flows	<u>761,506</u>	<u>915,796</u>	<u>2,046,672</u>
10% annual discount	<u>(146,519)</u>	<u>(122,692)</u>	<u>(525,083)</u>
Standardized measure of discounted future net cash flows	<u>\$614,987</u>	<u>\$793,104</u>	<u>\$1,521,589</u>

	Changes in Standardized Measure		
	Year Ended December 31,		
	2009	2008	2007
Standardized measure at beginning of year	\$793,104	\$1,521,589	\$1,248,830
Sales and transfers of oil and gas produced, net of production costs.....	(546,737)	(618,618)	(593,605)
Changes in price, net of future production costs.....	284,504	(2,209,114)	857,529
Extensions and discoveries, net of future production and development costs.....	21,249	37,201	114,729
Changes in estimated future development costs, net of development costs incurred during the period.....	183,058	98,029	(25,223)
Revisions of quantity estimates.....	(150,609)	(220,387)	363,783
Accretion of discount.....	79,904	203,715	142,605
Net change in income taxes	(27,436)	509,621	(338,336)
Purchases of reserves in-place	-	1,514,487	-
Sales of reserves in-place.....	3,152	(45,822)	(202,648)
Changes in production rates due to timing and other.....	(25,202)	2,403	(46,075)
Net increase (decrease) in standardized measure.....	(178,117)	(728,485)	272,759
Standardized measure at end of year	<u>\$614,987</u>	<u>\$793,104</u>	<u>\$1,521,589</u>

NOTE 19 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

	Three Months Ended			
	March 31,	June 30,	Sept. 30,	Dec. 31,
2009				
Operating revenue.....	\$142,943	\$170,312	\$202,719	\$199,620
Income (loss) from operations	(343,368) (a)	45,679	82,886	(92,909) (b)
Net income (loss) attributable to Stone Energy.....	(225,866) (a)	27,168	51,053	(64,063) (b)
Basic earnings (loss) per common share attributable to Stone Energy Corp. stockholders...	(\$5.73)	\$0.65	\$1.06	(\$1.35)
Diluted earnings (loss) per common share attributable to Stone Energy Corp. stockholders...	(\$5.73)	\$0.65	\$1.06	(\$1.35)
(a) Includes a ceiling test write-down of \$340,083 before taxes (\$221,054 after taxes).				
(b) Includes a ceiling test write-down of \$165,057 before taxes (\$107,287 after taxes).				
2008				
Operating revenue.....	\$203,233	\$262,962	\$172,355	\$166,104
Income (loss) from operations	92,292	124,262	55,250	(1,776,842) (b)
Net income (loss) attributable to Stone Energy.....	62,242	82,811	34,121	(1,316,405) (b)
Basic earnings (loss) per common share attributable to Stone Energy Corp. stockholders...	\$2.24	\$2.95	\$1.05	(\$33.40)
Diluted earnings (loss) per common share attributable to Stone Energy Corp. stockholders...	\$2.22	\$2.91	\$1.04	(\$33.40)

(b) Includes a ceiling test write-down of \$1,290,544 before taxes (\$838,854 after taxes) and goodwill impairment of \$465,985 (no tax effect).

NOTE 20 – GUARANTOR FINANCIAL STATEMENTS:

Stone Offshore is an unconditional guarantor (the “Guarantor Subsidiary”) of our 8¼% Senior Subordinated Notes due 2011 and 6¾% Senior Subordinated Notes due 2014 (see **Note 11 – Long-Term Debt**). Our remaining subsidiaries (the “Non-Guarantor Subsidiaries”) have not provided guarantees. The following presents consolidating financial information as of December 31, 2009 and 2008 and for the years ended December 31, 2009 and 2008 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiary, and consolidated basis. Elimination entries presented are necessary to combine the entities. There were no subsidiary guarantees of any of our debt for the year ended December 31, 2007.

CONSOLIDATING BALANCE SHEET (UNAUDITED)

DECEMBER 31, 2009

(In thousands of dollars)

	<u>Parent</u>	<u>Guarantor Subsidiary</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
Assets					
Current assets:					
Cash and cash equivalents	\$64,830	\$3,963	\$500	\$ -	\$69,293
Accounts receivable	53,396	169,053	144	(104,464)	118,129
Fair value of hedging contracts	16,223	-	-	-	16,223
Deferred tax asset	14,571	-	-	-	14,571
Inventory	8,145	572	-	-	8,717
Other current assets	771	43	-	-	814
Total current assets	157,936	173,631	644	(104,464)	227,747
Oil and gas properties – United States					
Proved, net	76,066	774,980	5,421	-	856,467
Unevaluated	226,289	102,953	-	-	329,242
Building and land, net	5,723	-	-	-	5,723
Fixed assets, net	4,084	-	-	-	4,084
Other assets, net	29,208	-	-	-	29,208
Fair value of hedging contracts	1,771	-	-	-	1,771
Investment in subsidiary	568,794	1,639	-	(570,433)	-
Total assets	\$1,069,871	\$1,053,203	\$6,065	(\$674,897)	\$1,454,242
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable to vendors	\$135,519	\$35,247	\$561	(\$104,464)	\$66,863
Undistributed oil and gas proceeds	14,828	452	-	-	15,280
Fair value of hedging contracts	34,859	-	-	-	34,859
Asset retirement obligations	9,597	20,918	-	-	30,515
Current income tax payable	11,110	-	-	-	11,110
Other current liabilities	42,224	759	-	-	42,983
Total current liabilities	248,137	57,376	561	(104,464)	201,610
Long-term debt	575,000	-	-	-	575,000
Deferred taxes *	(177,883)	171,140	-	51,271	44,528
Asset retirement obligations	73,863	186,545	4,613	-	265,021
Fair value of hedging contracts	7,721	-	-	-	7,721
Other long-term liabilities	11,699	6,713	-	-	18,412
Total liabilities	738,537	421,774	5,174	(53,193)	1,112,292
Commitments and contingencies					
Stockholders' equity:					
Common stock	475	-	-	-	475
Treasury stock	(860)	-	-	-	(860)
Additional paid-in capital	1,324,336	2,016,364	1,639	(2,017,929)	1,324,410
Retained earnings (deficit)	(977,237)	(1,384,935)	(748)	1,396,225	(966,695)
Accumulated other comprehensive loss	(15,380)	-	-	-	(15,380)
Total Stone Energy stockholders' equity	331,334	631,429	891	(621,704)	341,950
Non-controlling interest	-	-	-	-	-
Total stockholders' equity	331,334	631,429	891	(621,704)	341,950
Total liabilities and stockholders' equity	\$1,069,871	\$1,053,203	\$6,065	(\$674,897)	\$1,454,242

* Deferred income taxes have been allocated to guarantor subsidiary where related oil and gas properties reside.

CONSOLIDATING BALANCE SHEET (UNAUDITED)
DECEMBER 31, 2008
(In thousands of dollars)

	<u>Parent</u>	<u>Guarantor Subsidiary</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
<u>Assets</u>					
Current assets:					
Cash and cash equivalents	\$67,122	\$818	\$197	\$ -	\$68,137
Accounts receivable	119,918	32,080	99	(456)	151,641
Fair value of hedging contracts	136,072	-	-	-	136,072
Current income tax receivable	29,480	1,703	-	-	31,183
Inventory	32,965	2,710	-	-	35,675
Other current assets	1,356	57	-	-	1,413
Total current assets	386,913	37,368	296	(456)	424,121
Oil and gas properties – United States					
Proved, net	654,048	474,953	1,582	-	1,130,583
Unevaluated	218,297	275,441	-	-	493,738
Building and land, net	5,615	-	-	-	5,615
Fixed assets, net	5,068	258	-	-	5,326
Other assets, net	46,620	-	-	-	46,620
Investment in subsidiary	199,932	1,475	-	(201,407)	-
Total assets	\$1,516,493	\$789,495	\$1,878	(\$201,863)	\$2,106,003
<u>Liabilities and Stockholders' Equity</u>					
Current liabilities:					
Accounts payable to vendors	\$82,129	\$61,582	\$761	(\$456)	\$144,016
Undistributed oil and gas proceeds	37,517	365	-	-	37,882
Deferred taxes	32,416	-	-	-	32,416
Asset retirement obligations	45,634	25,075	-	-	70,709
Other current liabilities	13,861	1,898	-	-	15,759
Total current liabilities	211,557	88,920	761	(456)	300,782
Long-term debt	825,000	-	-	-	825,000
Deferred taxes *	25,315	117,338	-	51,271	193,924
Asset retirement obligations	133,109	52,787	250	-	186,146
Fair value of hedging contracts	1,221	-	-	-	1,221
Other long-term liabilities	11,751	-	-	-	11,751
Total liabilities	1,207,953	259,045	1,011	50,815	1,518,824
Commitments and contingencies					
Stockholders' equity:					
Common stock	394	-	-	-	394
Treasury stock	(860)	-	-	-	(860)
Additional paid-in capital	1,257,633	1,647,428	1,474	(1,648,902)	1,257,633
Retained earnings (deficit)	(1,033,539)	(1,116,978)	(694)	1,396,224	(754,987)
Accumulated other comprehensive income	84,912	-	-	-	84,912
Total Stone Energy stockholders' equity	308,540	530,450	780	(252,678)	587,092
Non-controlling interest	-	-	87	-	87
Total stockholders' equity	308,540	530,450	867	(252,678)	587,179
Total liabilities and stockholders' equity	\$1,516,493	\$789,495	\$1,878	(\$201,863)	\$2,106,003

* Deferred income taxes have been allocated to guarantor subsidiary where related oil and gas properties reside.

CONSOLIDATING STATEMENT OF OPERATIONS (UNAUDITED)
YEAR ENDED DECEMBER 31, 2009
(In thousands of dollars)

	<u>Parent</u>	<u>Guarantor Subsidiary</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
Operating revenue:					
Oil production.....	\$136,513	\$302,429	\$ -	\$ -	\$438,942
Gas production.....	123,511	148,842	-	-	272,353
Derivative income, net	3,061	-	-	-	3,061
Total operating revenue	<u>263,085</u>	<u>451,271</u>	<u>-</u>	<u>-</u>	<u>714,356</u>
Operating expenses:					
Lease operating expenses.....	36,563	120,223	-	-	156,786
Other operational expense.....	2,400	-	-	-	2,400
Production taxes.....	6,022	1,898	-	-	7,920
Depreciation, depletion, amortization	47,695	211,465	479	-	259,639
Write-down of oil and gas properties.....	-	505,140	-	-	505,140
Accretion expense.....	9,768	23,203	45	-	33,016
Impairment of inventory	8,342	1,056	-	-	9,398
Salaries, general and administrative.....	41,178	184	5	-	41,367
Incentive compensation expense.....	6,402	-	-	-	6,402
Total operating expenses	<u>158,370</u>	<u>863,169</u>	<u>529</u>	<u>-</u>	<u>1,022,068</u>
Income (loss) from operations	<u>104,715</u>	<u>(411,898)</u>	<u>(529)</u>	<u>-</u>	<u>(307,712)</u>
Other (income) expenses:					
Interest expense	21,183	178	-	-	21,361
Interest income.....	(515)	(13)	-	-	(528)
Other (income) expense, net	(3,524)	223	(553)	-	(3,854)
Total other (income) expenses	<u>17,144</u>	<u>388</u>	<u>(553)</u>	<u>-</u>	<u>16,979</u>
Income (loss) before taxes	<u>87,571</u>	<u>(412,286)</u>	<u>24</u>	<u>-</u>	<u>(324,691)</u>
Provision (benefit) for income taxes:					
Current.....	30,376	-	-	-	30,376
Deferred	892	(144,278)	-	-	(143,386)
Total income taxes	<u>31,268</u>	<u>(144,278)</u>	<u>-</u>	<u>-</u>	<u>(113,010)</u>
	56,303	(268,008)	24	-	(211,681)
Less: net income attributable to non- controlling interest	<u>-</u>	<u>-</u>	<u>27</u>	<u>-</u>	<u>27</u>
Net income (loss) attributable to Stone Energy Corporation	<u>\$56,303</u>	<u>(\$268,008)</u>	<u>(\$3)</u>	<u>\$ -</u>	<u>(\$211,708)</u>

CONSOLIDATING STATEMENT OF OPERATIONS (UNAUDITED)
YEAR ENDED DECEMBER 31, 2008
(In thousands of dollars)

	<u>Parent</u>	<u>Guarantor Subsidiary</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
Operating revenue:					
Oil production.....	\$444,826	\$16,224	\$ -	\$ -	\$461,050
Gas production.....	305,637	31,028	-	-	336,665
Derivative income, net	3,327	-	-	-	3,327
Total operating revenue	<u>753,790</u>	<u>47,252</u>	<u>-</u>	<u>-</u>	<u>801,042</u>
Operating expenses:					
Lease operating expenses.....	142,513	28,594	-	-	171,107
Production taxes.....	7,722	268	-	-	7,990
Depreciation, depletion, amortization	252,021	36,310	53	-	288,384
Write-down of oil and gas properties.....	327,891	981,512	-	-	1,309,403
Goodwill impairment.....	-	465,985	-	-	465,985
Impairment of investment in subsidiary.....	1,447,497	-	-	(1,447,497)	-
Accretion expense.....	15,887	1,492	13	-	17,392
Salaries, general and administrative.....	42,949	555	-	-	43,504
Incentive compensation expense.....	2,315	-	-	-	2,315
Total operating expenses	<u>2,238,795</u>	<u>1,514,716</u>	<u>66</u>	<u>(1,447,497)</u>	<u>2,306,080</u>
Income (loss) from operations	<u>(1,485,005)</u>	<u>(1,467,464)</u>	<u>(66)</u>	<u>1,447,497</u>	<u>(1,505,038)</u>
Other (income) expenses:					
Interest expense	13,212	31	-	-	13,243
Interest income.....	(11,223)	(27)	-	-	(11,250)
Other (income) expense, net	(6,550)	45	705	-	(5,800)
Total other (income) expenses	<u>(4,561)</u>	<u>49</u>	<u>705</u>	<u>-</u>	<u>(3,807)</u>
Income (loss) before taxes	<u>(1,480,444)</u>	<u>(1,467,513)</u>	<u>(771)</u>	<u>1,447,497</u>	<u>(1,501,231)</u>
Provision (benefit) for income taxes:					
Current.....	6,998	-	-	-	6,998
Deferred	(71,657)	(350,535)	-	51,271	(370,921)
Total income taxes	<u>(64,659)</u>	<u>(350,535)</u>	<u>-</u>	<u>51,271</u>	<u>(363,923)</u>
	(1,415,785)	(1,116,978)	(771)	1,396,226	(1,137,308)
Less: net loss attributable to non- controlling interest	<u>-</u>	<u>-</u>	<u>(77)</u>	<u>-</u>	<u>(77)</u>
Net income (loss) attributable to Stone Energy Corporation	<u>(\$1,415,785)</u>	<u>(\$1,116,978)</u>	<u>(\$694)</u>	<u>\$1,396,226</u>	<u>(\$1,137,231)</u>

CONSOLIDATING STATEMENT OF CASH FLOWS (UNAUDITED)
YEAR ENDED DECEMBER 31, 2009
(In thousands of dollars)

	<u>Parent</u>	<u>Guarantor Subsidiary</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
Cash flows from operating activities:					
Net income (loss).....	\$56,303	(\$268,008)	\$24	\$ -	(\$211,681)
<i>Adjustments to reconcile net income (loss) to net cash provided by operating activities:</i>					
Depreciation, depletion and amortization ...	47,695	211,465	479	-	259,639
Write-down of oil and gas properties.....	-	505,140	-	-	505,140
Impairment of inventory	8,342	1,056	-	-	9,398
Accretion expense.....	9,768	23,203	45	-	33,016
Deferred income tax provision (benefit)	892	(144,278)	-	-	(143,386)
Settlement of asset retirement obligations ..	(9,364)	(57,416)	-	-	(66,780)
Non-cash stock compensation expense.....	5,944	-	-	-	5,944
Excess tax benefits.....	(2)	-	-	-	(2)
Non-cash derivative expense	5,142	-	-	-	5,142
Other non-cash expenses	1,573	-	-	-	1,573
Change in current income taxes.....	64,481	1,704	-	-	66,185
(Increase) decrease in accounts receivable	177,984	(127,809)	440	(456)	50,159
Increase in other current assets	585	42	-	-	627
Increase in inventory.....	16,478	1,083	-	-	17,561
Decrease in accounts payable	(5,652)	(3,787)	(761)	-	(10,200)
Increase in other current liabilities.....	(19,448)	5,017	-	-	(14,431)
Other.....	739	(856)	-	-	(117)
Net cash provided by operating activities.....	361,460	146,556	227	(456)	507,787
Cash flows from investing activities:					
Investment in oil and gas properties	(177,341)	(143,405)	76	456	(320,214)
Proceeds from sale of oil and gas properties, net of expenses.....	5,553	-	-	-	5,553
Sale of fixed assets	-	35	-	-	35
Investment in fixed and other assets	(1,412)	-	-	-	(1,412)
Acquisition of non-controlling interest in subsidiary	-	(41)	-	-	(41)
Net cash provided by (used in) investing activities.....	(173,200)	(143,411)	76	456	(316,079)
Cash flows from financing activities:					
Repayments of bank borrowings.....	(250,000)	-	-	-	(250,000)
Deferred financing costs	(141)	-	-	-	(141)
Excess tax benefits.....	2	-	-	-	2
Proceeds from stock offering	60,447	-	-	-	60,447
Purchase of treasury stock	(347)	-	-	-	(347)
Net proceeds from exercise of stock options and vesting of restricted stock...	(513)	-	-	-	(513)
Net cash used in financing activities.....	(190,552)	-	-	-	(190,552)
Net increase (decrease) in cash and cash equivalents	(2,292)	3,145	303	-	1,156
Cash and cash equivalents, beginning of period	67,122	818	197	-	68,137
Cash and cash equivalents, end of period.....	\$64,830	\$3,963	\$500	\$ -	\$69,293

CONSOLIDATING STATEMENT OF CASH FLOWS (UNAUDITED)
YEAR ENDED DECEMBER 31, 2008
(In thousands of dollars)

	<u>Parent</u>	<u>Guarantor Subsidiary</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Eliminations</u>	<u>Consolidated</u>
Cash flows from operating activities:					
Net income (loss).....	(\$1,415,785)	(\$1,116,978)	(\$771)	\$1,396,226	(\$1,137,308)
<i>Adjustments to reconcile net income (loss) to net cash provided by operating activities:</i>					
Depreciation, depletion and amortization ...	252,021	36,310	53	-	288,384
Write-down of oil and gas properties.....	327,891	981,512	-	-	1,309,403
Goodwill impairment.....	-	465,985	-	-	465,985
Impairment of investment in subsidiary.....	1,447,497	-	-	(1,447,497)	-
Accretion expense.....	15,887	1,492	13	-	17,392
Deferred income tax benefit	(71,657)	(350,535)	-	51,271	(370,921)
Settlement of asset retirement obligations ..	(47,617)	(1,625)	-	-	(49,242)
Non-cash stock compensation expense.....	8,405	-	-	-	8,405
Excess tax benefits.....	(3,045)	-	-	-	(3,045)
Non-cash derivative expense	(2,592)	-	-	-	(2,592)
Other non-cash expenses	1,687	-	-	-	1,687
Decrease in current income taxes payable ..	(87,110)	-	-	-	(87,110)
(Increase) decrease in accounts receivable	70,983	39,182	68	456	110,689
Increase in other current assets	(824)	(42)	-	-	(866)
Increase in inventory.....	(32,965)	(565)	-	-	(33,530)
Decrease in accounts payable	12,718	11,455	777	-	24,950
Increase in other current liabilities.....	(299)	(17,481)	-	-	(17,780)
Investment in hedging contracts	(1,914)	-	-	-	(1,914)
Other.....	3,724	(3,833)	-	-	(109)
Net cash provided by operating activities.....	477,005	44,877	140	456	522,478
Cash flows from investing activities:					
Acquisition of Bois d' Arc Energy, Inc.	(929,542)	6,771	57	-	(922,714)
Investment in oil and gas properties	(395,848)	(50,467)	-	(456)	(446,771)
Proceeds from sale of oil and gas properties, net of expenses.....	13,339	-	-	-	13,339
Sale of fixed assets	4	-	-	-	4
Investment in fixed and other assets	(1,402)	(363)	-	-	(1,765)
Net cash provided by (used in) investing activities.....	(1,313,449)	(44,059)	57	(456)	(1,357,907)
Cash flows from financing activities:					
Proceeds from bank borrowings	425,000	-	-	-	425,000
Deferred financing costs	(8,766)	-	-	-	(8,766)
Excess tax benefits.....	3,045	-	-	-	3,045
Expenses for stock offering	(54)	-	-	-	(54)
Purchase of treasury stock	(6,724)	-	-	-	(6,724)
Net proceeds from exercise of stock options and vesting of restricted stock...	15,939	-	-	-	15,939
Net cash provided by financing activities.....	428,440	-	-	-	428,440
Net increase (decrease) in cash and cash equivalents	(408,004)	818	197	-	(406,989)
Cash and cash equivalents, beginning of period	475,126	-	-	-	475,126
Cash and cash equivalents, end of period.....	\$67,122	\$818	\$197	\$ -	\$68,137

GLOSSARY OF CERTAIN INDUSTRY TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this Form 10-K. The revisions and additions to the definition section in Rule 4-10(a) of Regulation S-X contained in the SEC's new rule, "Modernization of Oil and Gas Reporting", are included. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the new rule.

Bcf. One billion cubic feet of gas.

Bcfe. One billion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

Bbl. One stock tank barrel, or 42 U.S. gallons of liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

Gross acreage or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

LIBOR. Represents the London Inter-Bank Offering Rate of interest.

Liquidity. The ability to obtain cash quickly either through the conversion of assets or the incurrence of liabilities.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of gas.

Mcfe. One thousand cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBtu. One million Btus.

MMcf. One million cubic feet of gas.

MMcfe. One million cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six mcf of natural gas.

Make-Whole Amount. The greater of 104.125% of the principal amount of the 8¼% Notes (103.375% of the principal amount of the 6¾% Notes) and the sum of the present values of the remaining scheduled payments of principal and interest discounted to the date of redemption on a semiannual basis at the applicable treasury rate plus 50 basis points.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells expressed as whole numbers and fractions of whole numbers.

Overriding royalty interest. An interest in an oil and gas property entitling the owner to a share of oil or gas production free of production and capital costs.

Pari Passu. The term is Latin and translates to “without partiality.” Commonly refers to two securities or obligations having equal rights to payment.

Primary term lease. An oil and gas property with no existing production, in which Stone has a specific time frame to establish production without losing the rights to explore the property.

Productive well. A well that is found to be mechanically capable of producing hydrocarbons in sufficient quantities that proceeds from the sale of such production exceeds production expenses and taxes.

Proved developed reserves. Proved reserves that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction technology equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved oil and gas reserves. Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Reasonable certainty is defined as “much more likely to be achieved than not”.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Standardized measure of discounted future net cash flows. The standardized measure represents value-based information about an enterprise’s proved oil and gas reserves based on estimates of future cash flows, including income taxes, from production of proved reserves assuming continuation of certain economic and operating conditions. Future cash flows are based on a twelve-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the twelve month period prior to the end of the reporting period.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas regardless of whether such acreage contains proved reserves.

Working interest. An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.