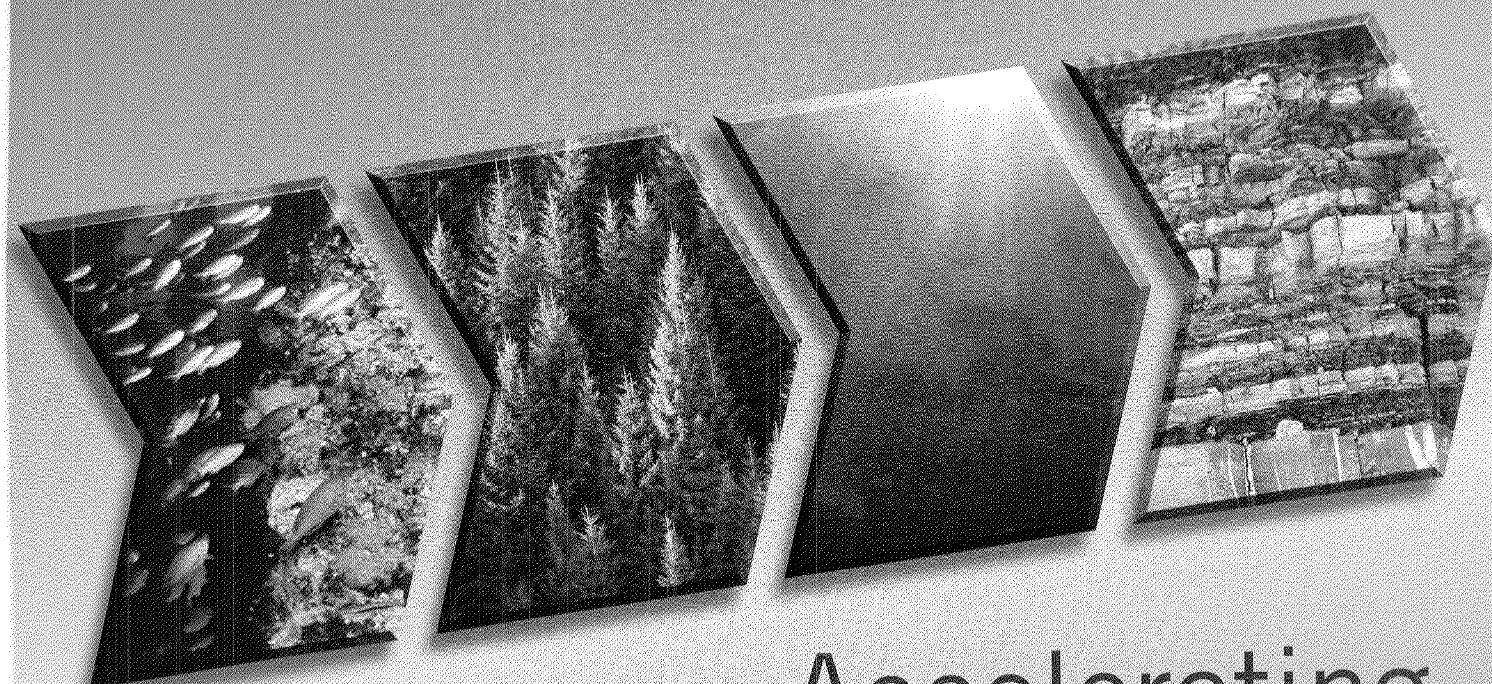
STONE
ENERGY

2012 ANNUAL REPORT



Accelerating

Summary Financial and Reserve Data

(In thousands, except per share and reserve data)

Year Ended December 31,	2012	2011	2010	2009*	2008*
Oil, gas and natural gas liquids revenues	$ 944,541	$ 864,565	$ 656,107	$ 711,295	$ 797,715
Income (loss) from operations	263,965	311,000	165,154	(313,525)	(1,513,973)
Net income (loss)	149,426	194,332	96,429	(218,298)**	(1,146,932)***
Diluted earnings (loss) per common share	$ 3.03	$ 3.97	$ 1.99	$ (4.97)	$ (35.89)
Weighted average shares outstanding (diluted)	48,361	48,030	47,706	43,953	31,961
Net cash provided by operating activities	$ 509,749	$ 570,850	$ 424,794	$ 507,787	$ 522,478
Net cash used in investing activities	(568,688)	(679,250)	(374,088)	(316,079)	(1,357,907)
Net cash provided by (used in) financing activities	300,014	39,895	(13,043)	(190,552)	428,440
Total assets	$ 2,776,431	$ 2,165,751	$ 1,679,090	$ 1,454,242	$ 2,109,852
Long-term debt	914,126	620,000	575,000	575,000	825,000
Stockholders' equity	872,133	667,829	430,357	325,659	577,391
Oil and condensate reserves (MBbls)	44,918	45,655	33,203	32,336	36,564
Natural gas liquids reserves (MBbls)	18,066	4,405	—	—	—
Gas reserves (MMcf)	395,374	325,479	274,705	216,694	299,554
Total estimated proved reserves (MBoe)	128,881	104,307	78,987	68,452	86,489
Total estimated proved reserves (MMcfe)	773,285	625,839	473,923	410,711	518,935

* Adjusted to correct for immaterial errors that were discovered in 2010.

** Includes an after-tax charge of $331 million due to a ceiling test write-down.

*** Includes an after-tax charge of $861 million due to a ceiling test write-down and $466 million goodwill impairment.

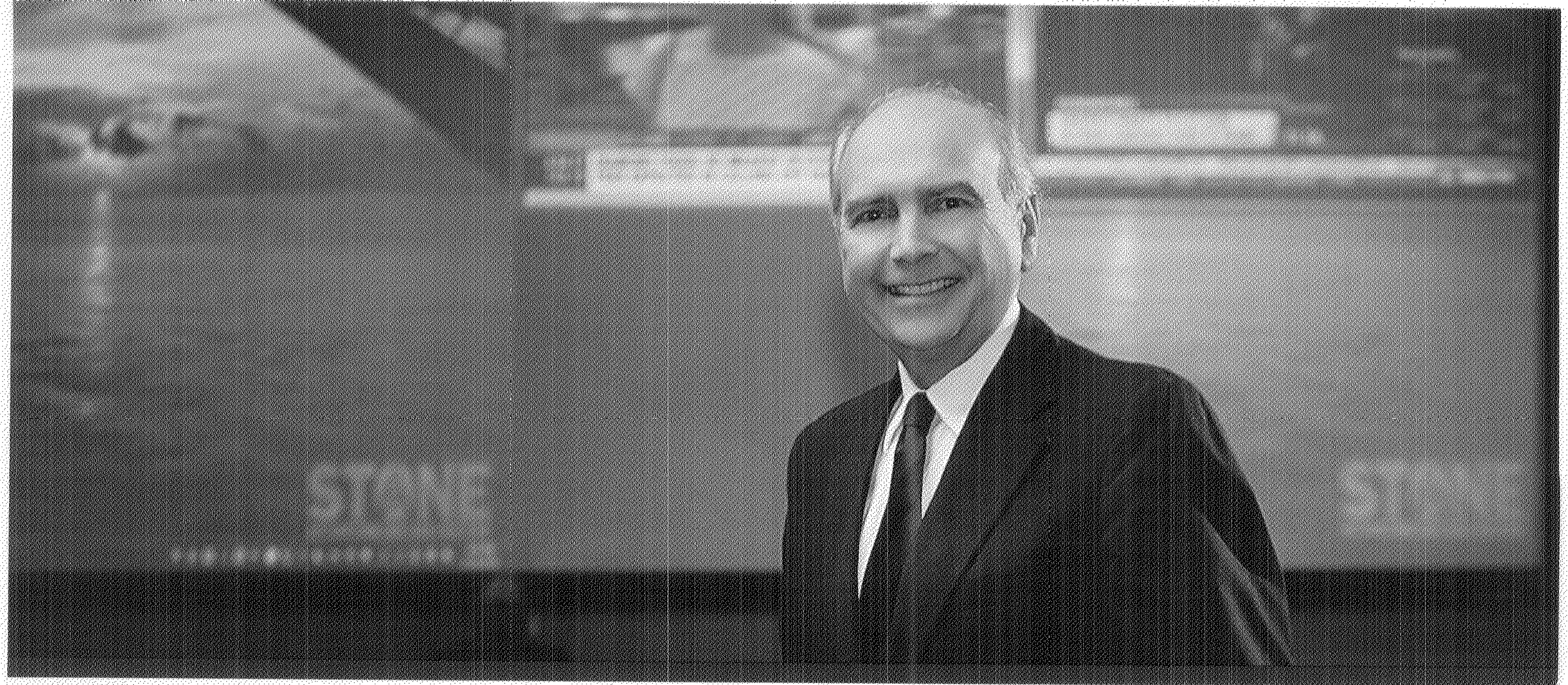
Stone Energy Corporation is an independent oil and natural gas exploration and production company headquartered in Lafayette, Louisiana, with additional offices in New Orleans, Houston and Morgantown, West Virginia. Our business strategy is to utilize cash flow generated from our existing conventional shelf Gulf of Mexico properties to:

SGY LISTED NYSE

- Profitably grow oil reserves and production in areas with a material impact (Deep Water GOM , Onshore Oil);
- Profitably grow gas reserves and production in price-advantaged basins (Appalachia, Gulf Coast Basin); and
- Maintain relatively stable GOM shelf oil production.

2012 Significant Events

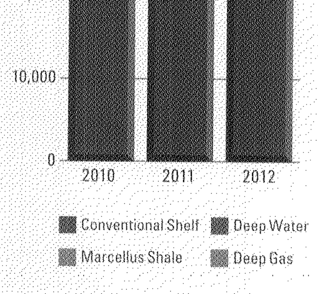
- Estimated proved reserves increased to 129 MMboe, representing an annual increase of 24 percent and a production replacement of 285 percent
- Increased average daily production rate for the year by 15 percent over 2011
- Acquired remaining 25 percent interest in the deep water Pompano field and successfully assumed operatorship of the field
- Initiated production from the La Cantera liquids rich deep gas discovery
- Awarded 23 Gulf of Mexico blocks at lease sale 216/222 and entered into joint venture deal with Conoco on four deep water prospects
- Drilled 23 horizontal wells and fractured 24 wells in the Marcellus shale in West Virginia, doubling production from 2011
- Completed a $300 million 1¾% Senior Convertible Notes offering due 2017, issued $300 million 7.50% Senior Notes due 2022 and retired our $200 million 2014 Senior Subordinated Notes



Dear Shareholders,

In 2012, we saw the acceleration of our strategy to shift our focus to the Gulf of Mexico (GOM) deep water, Gulf Coast liquids rich deep gas and Appalachian Marcellus shale from our legacy GOM shelf operations. This strategy has yielded over 20 percent compound annual growth rate in oil and gas reserves since 2009. By methodically investing in the Gulf of Mexico deep water, the Gulf Coast liquids rich deep gas and the Marcellus shale, we have transformed Stone from a company in which nearly 80 percent of our reserve base was located in our conventional shelf assets to a diversified company with over 80 percent of our reserves in our targeted growth areas.

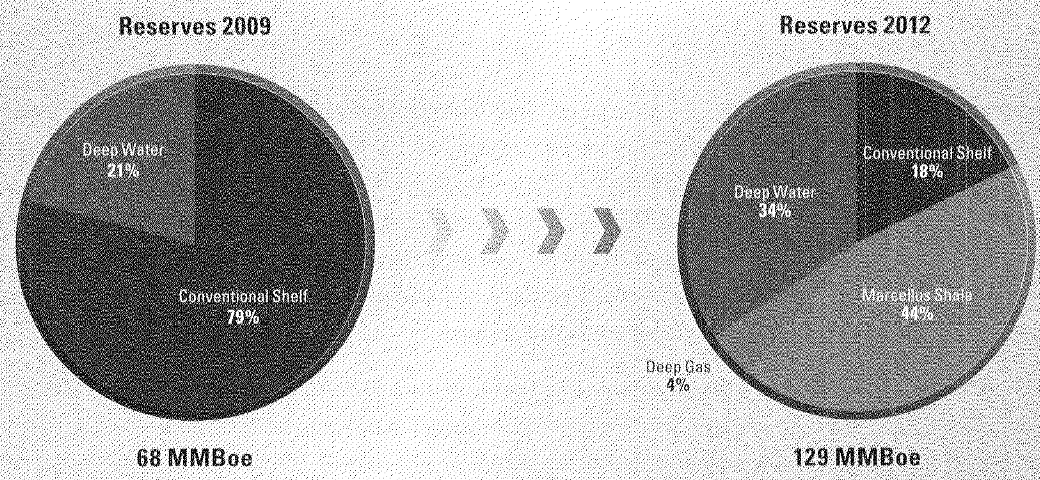
Production Rate BOEPD



In addition to increasing reserves, we also increased annual production by 15 percent. Again, the volume growth was anchored by production from deep water, deep gas and the Marcellus shale. The acquisition of the deep water Pompano field, along with the start-up of our Pyrenees and Wideberth deep water fields, more than doubled our deep water production. The accelerated development of the liquids rich deep gas La Cantera discovery provided us with a significant contribution to our 2012 volumes. Finally, in the Marcellus shale we increased production from 22 million cubic feet of gas equivalent (MMcfe) per day in the fourth quarter of 2011 to 51 MMcfe per day in the fourth quarter of 2012.

In the deep water, we consolidated our position in the strategic Pompano/Amberjack area of the GOM. Early in the year, we took over full operations of the Pompano platform and then acquired the outstanding 25 percent working interest, giving Stone 100 percent working interest in the platform. We completed several well-work projects on Pompano wells, boosting production during the year while reducing base lease operating costs by over 20 percent. Perhaps most importantly, we have matured development and exploration projects in the greater Pompano/Amberjack area and now expect to initiate Stone-operated open water drilling in late 2013, followed by a platform drilling program in 2014. Additionally, we are evaluating other third party prospects that might tie into the Pompano facilities.

Stone was also aggressive in the 2012 lease sale, adding 21 deep water lease blocks to our portfolio. As part of that effort, we entered into an attractive deep water exploration venture with ConocoPhillips on four prospects in the Mississippi Canyon area. We combined our high working interest lease blocks with newly acquired lease blocks through this partnership. This arrangement allowed Stone to leverage its acreage position for exploration capital. We are excited to be partnered with ConocoPhillips, and the preliminary drilling schedule calls for the initial prospect to be drilled in 2014.



We enhanced deep water production with a full year's volume from the Pyrenees field and the start-up of the Wideberth field. Wideberth was brought online in the second quarter via a subsea tie-back at an initial gross rate of approximately 6,000 barrels of oil equivalent (Boe) per day. The Parmer exploration well, located in the Green Canyon area, was drilled. It identified two previously undiscovered gas zones and provided additional information on the original oil zone. A follow-up delineation well is expected to be drilled after a full evaluation of recently completed seismic acquisition.

In our Gulf Coast liquids rich deep gas initiative, we successfully drilled a second well in the La Cantera field in 2012 and are drilling a third well in the first half of 2013. The La Cantera field, one of the largest onshore Louisiana discoveries in the past ten years, is currently producing over 80 MMcfe per day (gross) and Stone holds a 35 percent working interest in the field. The production stream contains significant condensate and natural gas liquids (NGLs) volumes, which serve to significantly enhance the financial results. In addition, Stone acquired interests in two other high potential prospects within the same mini-basin with plans to drill exploratory wells in 2013 and 2014.

Appalachia again provided significant reserve additions in 2012 and became a material production contributor for the company. By the end of 2012, Stone had drilled a total of 64 horizontal wells yielding estimated proved reserves in excess of 300 billion cubic feet of gas equivalent and producing over 50 MMcfe per day. Our efforts in the Marcellus shale are focused in our Mary and Heather fields in West Virginia where we receive the benefit of condensate and NGLs in the gas stream. The condensate and NGL volumes increase the overall effective realized gas price in these fields, boosting the economics of the play.

Drilling efficiencies continued in 2012 as we drilled more wells, with longer horizontal laterals, and more fracture stages at a lower cost per well. Not only do these efficiencies drive the cost of the horizontal wells down, but by extending the length of the horizontal section of the well, they also increase the expected ultimate recovery. We plan to maintain our focused Marcellus shale pad-drilling in the condensate rich Mary and Heather fields with over 250 potential gross drilling locations remaining to be drilled. In addition, Stone plans to test the economic viability of the Upper Devonian shale play, which overlays much of our existing Marcellus shale position. We expect 2013 to show continued production and reserve growth in Appalachia.

Our conventional shelf properties continue to provide us with production and cash flow to invest in our growth areas. The focused recompletion and drilling program has helped to offset the natural decline of the conventional shelf. We will continue to focus our drilling activities on oil prospects, with emphasis on our Ship Shoal 113 Unit and Main Pass 288 oil field. We have made significant progress on the mandated abandonment projects utilizing a more efficient liftboat to reduce overall cost. Stone was also able to negotiate a "rigs to reef" program that should provide the win/win situation of creating a thriving natural habitat while reducing the expense of removing platforms.

In 2012, we added liquidity and flexibility to our balance sheet. During the year, we issued $300 million Senior Convertible Notes due 2017 and $300 million Senior Notes due 2022 while retiring our $200 million Senior Subordinated Notes due 2014. As a result, we exited the year with over $250 million in cash, no bank debt, and the financial liquidity and flexibility to help fund our 2013 capital program.

Looking forward, we will continue to accelerate our strategy to grow and diversify into the price advantaged and material impact areas of Appalachia, the Gulf Coast deep gas and the GOM deep water. The Marcellus shale provides Stone with long-lived reserves, predictable production and a multiyear drilling program. The liquids rich deep gas program provides us with high impact wells that can be brought on production quickly. Exploration and exploitation in the deep water provides us with exposure to significant upside potential.

We are confident that we have the projects, the prospects and, most importantly, the people to accelerate growth. This is an exciting time for Stone and we appreciate the confidence of you, our shareholders.

Sincerely,

David H. Welch
Chairman, President and Chief Executive Officer

Senior Management

David H. Welch
Chairman, President and
Chief Executive Officer

Kenneth H. Beer
Executive Vice President
Chief Financial Officer

Andrew L. Gates III
Senior Vice President
General Counsel and Secretary

Kevin G. Hurst
Vice President – GOM Shelf/Deep Gas

E. J. Louviere
Senior Vice President – Land

J. Kent Pierret
Senior Vice President
Chief Accounting Officer and Treasurer

Keith A. Seilhan
Vice President – Deep Water

Richard L. Toothman, Jr.
Senior Vice President – Appalachia

Paul K. Wieg
Vice President –
Exploration and Business Development

Florence M. Ziegler
Vice President – Human Resources,
Communication and Administration

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012

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)

Delaware	**72-1235413**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
625 E. Kaliste Saloom Road Lafayette, Louisiana	**70508**
(Address of principal executive offices)	*(Zip Code)*

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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). [X] Yes [ ] No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. [X]

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 [X] Accelerated filer [ ] Non-accelerated filer [ ] (Do not check if a smaller reporting company) Smaller reporting company [ ]

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $1.2 billion as of June 30, 2012 (based on the last reported sale price of such stock on the New York Stock Exchange Composite Tape on that day).

As of February 21, 2013, the registrant had outstanding 49,259,243 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 23, 2013 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 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. 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. We have expanded our reserve base outside of the conventional shelf of the Gulf of Mexico ("GOM") and into the more prolific reserve basins of the GOM deep water and Gulf Coast deep gas, as well as onshore oil and gas shale opportunities, including the Marcellus Shale in Appalachia. As of December 31, 2012, our estimated proved oil and natural gas reserves were approximately 773 Bcfe. We were incorporated in 1993 as a Delaware corporation. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508. We have additional offices in New Orleans, Louisiana, Houston, Texas and Morgantown, West Virginia.

Strategy and Operational Overview

Our business strategy is to leverage cash flow generated from existing assets to maintain relatively stable GOM shelf production, profitably grow gas reserves and production in price-advantaged basins such as Appalachia and the Gulf Coast Basin, and profitably grow oil reserves and production in the deep water GOM and onshore oil areas.

Gulf of Mexico — Deep Water. We believe that the deep water of the GOM is an attractive area to explore and operate, even though it involves high risk, high costs and substantial lead time to develop infrastructure. We have made two significant acquisitions that included two deep water platforms, producing reserves and numerous leases. We have also utilized subsea tie-backs in the deep water on new drill wells that require less capital than a deep water facility. 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 exploration, development and acquisition opportunities. Our deep water properties accounted for approximately 34% of our estimated proved oil and natural gas reserves at December 31, 2012 on a volume equivalent basis.

Appalachia. During 2006, we began securing leasehold interests in the Appalachia regions of Pennsylvania and West Virginia. As of December 31, 2012, we had leasehold interests in approximately 93,000 net acres. During 2012, we drilled a total of 23 horizontal Marcellus shale wells and fractured 24 wells. We expect to add leasehold interests and drill additional wells to further expand our interests in Appalachia. Our Appalachian properties accounted for approximately 44% of our estimated proved oil and natural gas reserves at December 31, 2012 on a volume equivalent basis.

South Louisiana Gulf of Mexico — Deep Gas. The deep gas play provides us with high potential exploration opportunities with existing infrastructure nearby, which shortens the lead time to production. We have made two onshore south Louisiana deep gas discoveries and have identified other deep gas opportunities in south Louisiana. Additionally, our current property base in the GOM also contains multiple deep shelf exploration opportunities, which are defined as prospects below 15,000 feet. Our deep shelf gas properties accounted for approximately 4% of our estimated proved oil and natural gas reserves at December 31, 2012 on a volume equivalent basis.

Gulf of Mexico — Conventional Shelf (Including Onshore Louisiana). We seek to generate 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 provide production to help mitigate some of the natural decline of the GOM conventional shelf. Our GOM conventional shelf properties accounted for approximately 18% of our estimated proved oil and natural gas reserves at December 31, 2012 on a volume equivalent basis.

Onshore Oil. We maintain working interests in several undeveloped plays, which totaled approximately 92,000 net acres as of December 31, 2012. We have budgeted funds in 2013 for new venture opportunities. Our onshore oil properties accounted for less than 1% of our estimated proved oil and natural gas reserves at December 31, 2012 on a volume equivalent basis.

Oil and Gas Marketing

Our oil and natural gas production is sold at current market prices under short-term contracts. Shell Trading (US) Company, Phillips 66 Company and Conoco, Inc. accounted for approximately 41%, 18% and 13%, respectively, of our oil and natural gas revenue generated during the year ended December 31, 2012. 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 natural 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, the Gulf Coast onshore, the Appalachia region and other onshore oil plays 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, 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 ratability 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 ("BLM") and the Bureau of Ocean Energy Management ("BOEM"), a successor agency to the Minerals Management Service. These leases contain relatively standardized terms and require compliance with detailed BLM and BOEM regulations and orders pursuant to various federal laws, including the Outer Continental Shelf Lands Act, 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 or the manner in which certain activities may be conducted or, in some cases, may ban any surface activity. For offshore operations, lessees must obtain BOEM 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 ("EPA")), lessees must obtain a permit from the BLM or the BOEM, 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 ("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 BOEM generally requires that lessees post substantial bonds or other acceptable assurances that such obligations will be met, unless the BOEM 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 the Bureau of Safety and Environmental Enforcement ("BSEE"), a new federal agency created to enforce compliance with safety and environmental rules of the OCS, 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.

Natural Gas. In 2005, the United States Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 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. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1 million 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. The U.S. Commodity Futures Trading Commission ("CFTC") has similar authority with respect to energy futures commodity markets. Stone Energy does not anticipate it will be affected any differently by these requirements than other producers of natural gas.

In 2007, the FERC issued Order No. 704 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. The monitoring and reporting required by these rules have increased our administrative costs. Stone Energy does not anticipate it will be affected any differently by these requirements 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 such as 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. Similarly, the natural gas pipeline industry is also subject to state regulations, which may change from time to time in ways that affect the availability, terms and cost of transportation. However, we do not believe that any such changes would affect our business in a way that would be materially different from the way such changes would affect our competitors.

Oil. Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the Federal Trade Commission ("FTC") issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale, from knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person or intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the FTC Act.

Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are transacted at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. The price we receive from the sale of oil and natural gas liquids is affected by the cost of transporting those products to market. Interstate transportation rates for oil, natural gas liquids and other products are regulated by the FERC. The FERC has established an indexing system for such transportation, which allows such pipelines to take an annual inflation-based rate increase.

In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. As it relates to intrastate crude oil, condensate and natural gas liquids pipelines, state regulation is generally less rigorous than the federal regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests, which are infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate and natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Miscellaneous. Additional proposals and proceedings that might affect the oil and gas industry are regularly considered by the United States Congress, state regulatory bodies, 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.

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 may 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 strict, joint and several 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.

Oil Pollution Act. The Oil Pollution Act of 1990 ("OPA") and regulations adopted pursuant thereto 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. Although defenses exist to the liability imposed by the OPA, they are limited. The OPA also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. The OPA currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the OCS, although the Secretary of the Interior may increase this amount up to $150 million in certain situations. We cannot predict at this time whether the OPA will be amended or whether the level of financial responsibility required for companies operating on the OCS will be increased. In any event, if there were to occur an oil discharge or substantial threat of discharge, we may be liable for costs and damages, which costs and damages could be material to our results of operations and financial position.

Climate Change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the Clean Air Act

("CAA"). The EPA adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective as of January 2, 2011. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, on an annual basis, beginning in 2011 for emissions occurring in 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011. We believe that we are in compliance with all greenhouse gas emissions reporting requirements applicable to our operations.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such climate changes were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act's ("SDWA") Underground Injection Control Program. The EPA has also commenced a study of the potential environmental impacts of hydraulic fracturing activities on water resources. The EPA's study includes 18 separate research projects addressing topics such as water acquisitions, chemical mining, well injections, flowback and produced water, wastewater treatment and waste disposal. The EPA has indicated that it expects to issue its study report in late 2014. In addition, a number of other federal agencies, including the U.S. Department of Energy, the U.S. Department of the Interior, and the White House Council on Environmental Quality, are studying various aspects of hydraulic fracturing. Legislation has been introduced before the United States Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. For example, Pennsylvania, Texas, Colorado and Wyoming have each adopted a variety of well construction, set back and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could impact the timing of production and may also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Air emissions. In August 2012, the EPA adopted new rules that establish air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA established New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The EPA's rules require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The requirement for flaring of gas not sent to a gathering line became effective on October 15, 2012, and all operators are required to use "green completions" drilling equipment beginning January 1, 2015. The rules also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants. These rules may require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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 21, 2013, we had 386 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, as amended ("Exchange Act"), and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the Securities and Exchange Commission ("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 5, 2012.

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, as amended ("Securities Act"), and Section 21E of the Exchange Act. 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;
- expected results from risked weighted drilling success;
- 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;
- our access to capital and our anticipated liquidity;
- 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;
- consequences of a catastrophic event like the Deepwater Horizon oil spill;
- 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 bank 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 and cost 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;
- adverse effects of changes in applicable tax, environmental, derivatives and other regulatory legislation, including changes affecting our offshore and Appalachian operations;
- uncertainty inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures; and
- 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:

New regulatory requirements and permitting procedures imposed by the BOEM could significantly delay our ability to obtain permits to drill new wells in offshore waters.

Subsequent to the Deepwater Horizon incident in the GOM in April 2010, the BOEM issued a series of "Notice to Lessees" ("NTLs") imposing new regulatory requirements and permitting procedures for new wells to be drilled in federal waters of the OCS. These new regulatory requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases oil spill response requirements.

- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes and also requires certifications of compliance from senior corporate officers.

- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain well bore integrity and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.

- The Workplace Safety Rule, which requires operators to employ a comprehensive safety and environmental management system ("SEMS") to reduce human and organizational errors as root causes of work-related accidents and offshore spills and to have their SEMS periodically audited by an independent third party auditor approved by the BSEE.

Since the adoption of these new regulatory requirements, the BOEM has been taking much longer to review and approve permits for new wells than was common prior to the Deepwater Horizon incident. The new rules also increase the cost of preparing each permit application and will increase the cost of each new well, particularly for wells drilled in deeper waters on the OCS. We could become subject to fines, penalties or orders requiring us to modify or suspend our operations in the GOM if we fail to comply with the BOEM's NTLs or other regulatory requirements.

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. 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;
- level of consumer product demands;
- hurricanes and other weather conditions;
- domestic governmental regulations and taxes;
- 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;
- foreign supply of oil and natural gas;
- price of oil and natural 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. GOM 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 18% of our estimated proved reserves at December 31, 2012 (by volume) and 56% of our production during 2012 were associated with our Gulf Coast Basin conventional shelf 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, acquire additional reserves or 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.

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

This Form 10-K contains estimates of our proved oil and natural 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 natural 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 Form 10-K 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, 2012 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, 2012, approximately 44% 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 flow 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 bank 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.

Our estimates of future asset retirement obligations may vary significantly from period to period.

We are required to record a liability for the discounted present value of our asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations due to increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. Estimating future restoration and removal costs in the GOM is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, we may make significant increases or decreases to our estimated asset retirement obligations in future periods. For example, because we operate in the GOM, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled rather than structurally intact. Accordingly, our estimate of future asset retirement obligations could differ dramatically from what we may ultimately incur as a result of damage from a hurricane.

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 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 operating activities 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 bank 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 2013. 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 bank credit facility and our indentures, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through offerings 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 offerings, refinancing or sale of assets. We cannot assure you that any such offerings, 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 GOM.

Approximately 18% of our estimated proved reserves at December 31, 2012 (by volume) and 56% of our production during 2012 were associated with our Gulf Coast Basin conventional shelf properties. Approximately 38% of our estimated proved reserves at December 31, 2012 (by volume) and 27% of our production during 2012 were associated with our GOM deep water and deep shelf gas 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 GOM. In past years, we have experienced shut-ins and losses of production due to the effects of hurricanes in the GOM. We are unable to predict what impact future hurricanes and tropical storms might have on our future results of operations and production.

Our acreage must be drilled before lease expiration in order to hold the acreage by production. If natural gas prices remain depressed for an extended period of time, it might not be economical for us to drill sufficient wells in order to hold acreage, which could result in the expiry of a portion of our acreage, which could have an adverse effect on our business.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage may expire. See "**Item 2. Properties – Productive Well and Acreage Data**."

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 gathering systems, pipelines and processing facilities could result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. The disruption of these gathering systems, pipelines and processing facilities due to maintenance and/or weather could negatively impact our ability to market and deliver our products. 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.

Our actual production could differ materially from our forecasts.

From time to time, we provide forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production from existing wells. In addition, our forecasts assume that none of the risks associated with our oil and gas operations summarized in this Item 1A occur, such as facility or equipment malfunctions, adverse weather effects, or significant declines in commodity prices or material increases in costs, which could make certain production uneconomical.

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. 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. 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 the Rocky Mountain region and other regions. These activities are more uncertain than drilling in areas that are developed and have established production. Our operations in these regions are still in the early stages. 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 us 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 these 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. We are also involved in drilling operations that utilize hydraulic fracturing, which may potentially present additional operational and environmental risks. 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 insure some, but not all, of our properties from operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of wells, oil pollution, workers' compensation and employers' liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages and losses.

Currently, we have general liability insurance coverage with an annual aggregate limit of up to $375 million on a 100% working interest basis. We currently purchase an offshore property physical damage policy that contains an $80 million annual aggregate named windstorm limit. Our operational control of well coverage provides limits that vary by well location and depth and range from a combined single limit of $20 million to $300 million per occurrence. Exploratory deep water wells have a coverage limit of $600 million per occurrence. Additionally, we maintain $150 million in oil pollution liability coverage. Our general liability, control of well and oil pollution liability policy limits are scaled proportionately to our working interests, and all of our policies described above are subject to deductibles, sub-limits and/or self-insurance. Under our service agreements, including drilling contracts, generally we are indemnified for injuries and death of the service provider's employees as well as contractors and subcontractors hired by the service provider.

An operational or hurricane related event may cause damage or liability in excess of our coverage, which might severely impact our financial position. We may be liable for damages from an event relating to a project in which we are a non-operator, but have a working interest in such project. Such an event may also cause a significant interruption to our business, which might also severely impact our financial position. In past years, we have experienced production interruptions for which we had no production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually each May. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the GOM, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of 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 affect on our financial condition and operations.

Competition within our industry may adversely affect our operations.

Competition within our industry 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 United States federal, state and local governmental regulations that materially affect our operations.

Our oil and gas operations are subject to various United States 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 the OPA and other environmental statutes such as the federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and Resource Conservation and Recovery Act ("RCRA") and analogous state laws, 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 the 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") or the Intercontinental Exchange ("ICE"). 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.

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 is 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 of directors 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.

Legislation may be proposed that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These 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 whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our common stock.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. The EPA adopted two sets of rules regulating greenhouse gas emissions under the CAA, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulates emissions of greenhouse gases from certain large stationary sources, effective as of January 2, 2011. The EPA's rules relating to emissions of greenhouse gases from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States, on an annual basis, beginning in 2011 for emissions occurring in 2010, as well as certain onshore oil and natural gas production facilities, on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall greenhouse gas emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Act the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012 although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap," "security-based swap," "swap dealer" and "major swap participant." The Act and CFTC Rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Act and CFTC rules on us and the timing of such effects. The Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of some derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act and regulations is to lower commodity prices. Any of these consequences could have material adverse effect on our financial condition and our results of operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could cause us to incur increased costs and experience additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA's Underground Injection Control Program. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a number of federal agencies are analyzing a number of environmental issues associated with hydraulic fracturing. The EPA has commenced a comprehensive study of the potential environmental effects of hydraulic fracturing activities on water resources. The EPA's study includes 18 separate research projects addressing topics such as water acquisition, chemical mixing, well injection, flowback and produced water, wastewater treatment and waste disposal. The EPA has indicated that it expects to issue its study report in late 2014. In addition, the U.S. Department of Energy and the U.S. Government Accountability Office are studying various aspects of hydraulic fracturing, and the U.S. Department of the Interior is considering adopting new permitting and disclosure requirements for hydraulic fracturing activities performed on federal lands. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or other federal programs. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including states in which we operate. For example, effective February 1, 2012, the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) began requiring all operators to disclose on a public website the chemical ingredients and water volumes used to hydraulically fracture wells in Texas. The disclosure of proprietary information regarding chemicals or formulas used in hydraulic fracturing could diminish the value of such information and could result in competitive harm to us. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could impact the timing of production and may also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As of February 21, 2013, our property portfolio consisted of 65 active properties and 129 primary term leases in the Gulf Coast Basin (onshore and offshore), five active properties in the Appalachia region, three active properties in the Rocky Mountain region and one active property in the Eagle Ford Shale formation. We serve as operator on 71% of our active properties. The properties that we operate accounted for 92% of our year-end 2012 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

Our Reserves Committee Charter provides that the reserves committee has the sole authority to recommend to the board of directors appointments or replacements of one or more firms of independent reservoir engineers and geoscientists. The reserves committee reviews annually the arrangements of the independent reservoir engineers and geoscientists with management, including the scope and general extent of the examination of our reserves, the reports to be rendered, the services and fees and consideration of the independence of such independent reservoir engineers and geoscientists. The reserves committee may consult with management but may not delegate these responsibilities. The reserves committee provides oversight in regards to the reserve estimation process but not the actual determination of estimated proved reserves. Our Reserves Committee Charter provides that it is the duty of management and not the duty of the reserves committee to plan or conduct reviews or to determine that our reserve estimates are complete and accurate and are in accordance with generally accepted engineering standards and applicable rules and regulations of the SEC. Our Director of Strategic Planning is the in-house person designated as primarily responsible for the process of reserve preparation. He is a petroleum engineer with over twenty years of experience in reservoir engineering and analysis. His duties include oversight of the preparation of non year-end quarterly reserve estimates and coordination with the outside engineering consultants on the preparation of year-end reserve estimates. The year-end reserve estimates prepared by our outside engineering firm are independent of any oversight of the Director of Strategic Planning or the reserves committee.

Estimates of our proved reserves at December 31, 2012 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 has a technical staff of over 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 Form 10-K.

The following table sets forth our estimated proved oil and gas reserves (approximately 44% of which are located in the Appalachian region, 34% are located in the GOM deep water and 22% are located in the conventional shelf/deep gas) as of

December 31, 2012. The 2012 average 12-month oil and gas prices net of differentials were $101.20 per Bbl of oil, $38.23 per Bbl of natural gas liquids ("NGLs") and $2.68 per Mcf of gas.

Summary of Oil, Natural Gas and NGL Reserves as of December 31, 2012

	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Oil, Natural Gas and NGL's (MMcfe)
Reserves Category:				
PROVED				
Developed	29,005	8,592	210,956	436,540
Undeveloped	15,913	9,474	184,418	336,745
TOTAL PROVED	44,918	18,066	395,374	773,285

At December 31, 2012, we reported estimated proved undeveloped reserves ("PUDs") of 336.7 Bcfe, which accounted for 44% of our total estimated proved oil and gas reserves. This figure ties to a projected 88 new wells (311.8 Bcfe) and ten sidetrack wells from existing wellbores (24.9 Bcfe). Our timetable for the ten sidetrack wells is totally dependent on the life of the currently producing zones. After the current zones have been depleted, we would utilize the existing wellbore to sidetrack to the PUD objective. Regarding the remaining 88 PUD locations, we project 25 wells to be drilled in 2013 (122.2 Bcfe); ten wells in 2014 (42.2 Bcfe); 29 wells in 2015 (76.9 Bcfe); fourteen wells in 2016 (41.3 Bcfe), and ten wells in 2017 (29.2 Bcfe). None of these 88 PUD wells will have been on our books in excess of five years at the time of their scheduled drilling. The following table discloses our progress toward the conversion of PUDs during 2012.

	Oil, Natural Gas and NGLs (MMcfe)	Future Development Costs ($ in thousands)
PUDs beginning of year	241,656	$607,995
Revisions of previous estimates	(47,153)	(176,995)
Conversions to proved developed reserves	(47,505)	(33,835)
Additional PUDs added	189,747	268,071
PUDs end of year	336,745	$665,236

During 2012 we invested approximately $33.8 million to convert 47.5 Bcfe of proved undeveloped reserves to proved developed reserves, mainly in the Appalachian region.

The following represents additional information on our significant properties:

Field Name	Location	2012 Production (MMcfe)	December 31, 2012 Estimated Proved Reserves (MMcfe)	Nature of Interest
Mary	Appalachia	11,544	281,843	Working
Pompano..	GOM Deep Water	10,310	175,642	Working
Mississippi Canyon Block 109	GOM Deep Water	9,765	75,291	Working
Bayou Hebert	GOM Deep Gas	3,254	33,317	Working
Heather	Appalachia	2,799	33,008	Working
Ship Shoal Block 113	GOM Shelf	11,745	25,657	Working
Ewing Bank Block 305	GOM Shelf	3,309	19,942	Working
Main Pass Block 288	GOM Shelf	2,756	13,080	Working

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 U.S. 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 during the periods indicated.

	Year Ended December 31,		
	2012	2011	2010
		(In thousands)	
Acquisition costs, net of sales of unevaluated properties	$102,807	$270,354	$127,069
Development costs (1)	395,555	426,355	241,387
Exploratory costs	81,458	84,199	42,205
Subtotal	579,820	780,908	410,661
Capitalized salaries, general and administrative costs and interest, net of fees and reimbursements	62,664	66,111	51,016
Total additions to oil and gas properties, net	$642,484	$847,019	$461,677

(1) Includes capitalized asset retirement costs of $95,293, $96,386 and $56,444 for the years ended December 31, 2012, 2011 and 2010, 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,		
	2012	2011	2010
Production:			
Oil (MBbls)	7,135	6,427	5,714
Natural gas (MMcf)	42,569	38,466	41,168
Natural gas liquids (MBbls)	1,163	506	574
Oil, natural gas and NGLs (MMcfe)	92,357	80,064	78,896
Average sales prices: (1)			
Oil (per Bbl)	$106.70	$103.31	$73.14
Natural gas (per Mcf)	3.17	4.44	5.12
Natural gas liquids (per Bbl)	41.70	59.28	47.86
Oil, natural gas and NGLs (per Mcfe)	10.23	10.80	8.32
Expenses (per Mcfe):			
Lease operating expenses (2)	$2.33	$2.20	$1.90

(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 December 31, 2012. We completed the acquisition of our interest in the Pompano field on December 28, 2011.

FIELD: Mary	**Year Ended December 31,**		
	2012	**2011**	**2010**
Production:			
Oil (MBbls)	340	25	-
Natural gas (MMcf)	6,815	977	79
Natural gas liquids (MBbls)	448	-	-
Oil, natural gas and NGLs (MMcfe)	11,544	1,125	79
Average sales prices:			
Oil (per Bbl)	$54.19	$75.60	$ -
Natural gas (per Mcf)	3.27	6.08	4.78
Natural gas liquids (per Bbl)	33.94	-	-
Oil, natural gas and NGLs (per Mcfe)	4.84	6.94	4.78
Expenses (per Mcfe):			
Lease operating expenses (1)	$1.14	$1.40	$1.51

FIELD: Pompano	**Year Ended December 31,**		
	2012	**2011(a)**	**2010**
Production:			
Oil (MBbls)	1,266	-	-
Natural gas (MMcf)	1,980	-	-
Natural gas liquids (MBbls)	122	-	-
Oil, natural gas and NGLs (MMcfe)	10,310	-	-
Average sales prices:			
Oil (per Bbl)	$108.65	$ -	$ -
Natural gas (per Mcf)	2.02	-	-
Natural gas liquids (per Bbl)	45.70	-	-
Oil, natural gas and NGLs (per Mcfe)	14.28	-	-
Expenses (per Mcfe):			
Lease operating expenses (1)	$2.01	$ -	$ -

(a) Amounts for 2011 are immaterial. We completed the acquisition of the Pompano field on December 28, 2011.

(1) 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,					
	2012		**2011**		**2010**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory Wells:						
Productive	1.00	0.43	6.00	3.00	6.00	4.10
Dry	-	-	1.00	0.64	-	-
Development Wells:						
Productive	33.00	23.16	37.00	32.92	20.00	15.75
Dry	3.00	3.00	-	-	-	-

During the period beginning January 1, 2013 and ending February 21, 2013, we participated in the drilling of 4.00 gross (3.05 net) development wells.

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, 2012.

	Gross	Net
Productive Wells:		
Oil (1):		
Gulf Coast Basin	175	129
Onshore Oil	10	4
Appalachia	-	-
	185	133
Gas (2):		
Gulf Coast Basin	71	43
Onshore Oil	-	-
Appalachia	65	44
	136	87
Total	321	220
Developed Acres:		
Gulf Coast Basin	307,868	279,881
Onshore Oil	30,361	30,361
Appalachia	27,101	26,247
	365,330	336,489
Undeveloped Acres (3):		
Gulf Coast Basin	539,878	535,193
Onshore Oil	65,771	62,174
Appalachia	75,794	66,992
	681,443	664,359
Total	1,046,773	1,000,848

(1) 15 gross wells each have dual completions.
(2) 8 gross wells each have dual completions.
(3) Leases covering approximately 14% of our undeveloped gross acreage will expire in 2013, 15% in 2014, 4% in 2015, 10% in 2016, 6% in 2017, 14% in 2018, 9% in 2019, 2% in 2020 and 26% thereafter.

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

On December 30, 2004, we were 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 (civil action number 2005-6524) in the 15th Judicial District Court claiming additional franchise taxes due for the franchise tax years 2002 and 2003 in the amount of $2.6 million, plus accrued interest of $1.2 million (calculated through December 15, 2005). Also, on January 2, 2008, we were 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, we were served with a petition (civil action number 2008-7193) claiming additional franchise taxes due for the franchise tax years 2005 and 2006 in the amount of $4.0 million, plus accrued interest of $1.7 million (calculated through October 21, 2008). In addition, we have received proposed assessments from the LDR for additional franchise taxes in the amount of $8.1 million resulting from audits of Stone and our subsidiaries. These assessments all relate to the LDR's assertion that sales of crude oil and natural gas from properties located on the OCS, 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. We disagree with these contentions and intend to vigorously defend ourselves against these claims. The franchise tax years 2010, 2011 and 2012 for Stone remain subject to examination.

In October 2012, we received a notice from BSEE that it was initiating an enforcement proceeding with respect to an Incident of Non-Compliance observed at our Vermillion Block 255 Platform H in April 2012. The notice indicates that BSEE may seek to impose a penalty of up to $25,000 a day for up to as many as eight days of alleged improper venting of gas at the platform. We believe that the conditions observed were not actually violations of applicable rules and have initiated discussions with BSEE to resolve the matter. We do not believe that this proceeding will have a material adverse effect on our financial condition or results of operations.

Litigation is subject to substantial uncertainties concerning the outcome of material factual and legal issues relating to the litigation. Accordingly, 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.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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
2011		
First Quarter	$33.49	$21.28
Second Quarter	35.94	27.44
Third Quarter	34.46	16.19
Fourth Quarter	29.71	14.64
2012		
First Quarter	$35.47	$25.61
Second Quarter	29.83	20.80
Third Quarter	27.87	22.07
Fourth Quarter	25.71	19.27
2013		
First Quarter (through February 21, 2013)	$23.40	$19.62

On February 21, 2013, the last reported sales price on the New York Stock Exchange Composite Tape was $20.62 per share. As of that date, there were 457 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 1¾% Senior Convertible Notes due 2017 (the "2017 Convertible Notes"), our 8⅝% Senior Notes due 2017 (the "2017 Notes") and our 7½% Senior Notes due 2022 (the "2022 Notes"). 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 are sometimes 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 2012:

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 2012	-	-	-	
November 2012	-	-	-	
December 2012	-	-	-	
	-	-	-	$92,928,632
Other:				
October 2012	-	-	-	
November 2012	-	-	-	
December 2012	-	-	-	
	-	-	-	N/A
Total Fourth Quarter 2012	-	$ -	-	

There were no repurchases of common stock under our share repurchase program and no shares withheld from employees to pay taxes associated with any vesting of restricted stock during the fourth quarter of 2012.

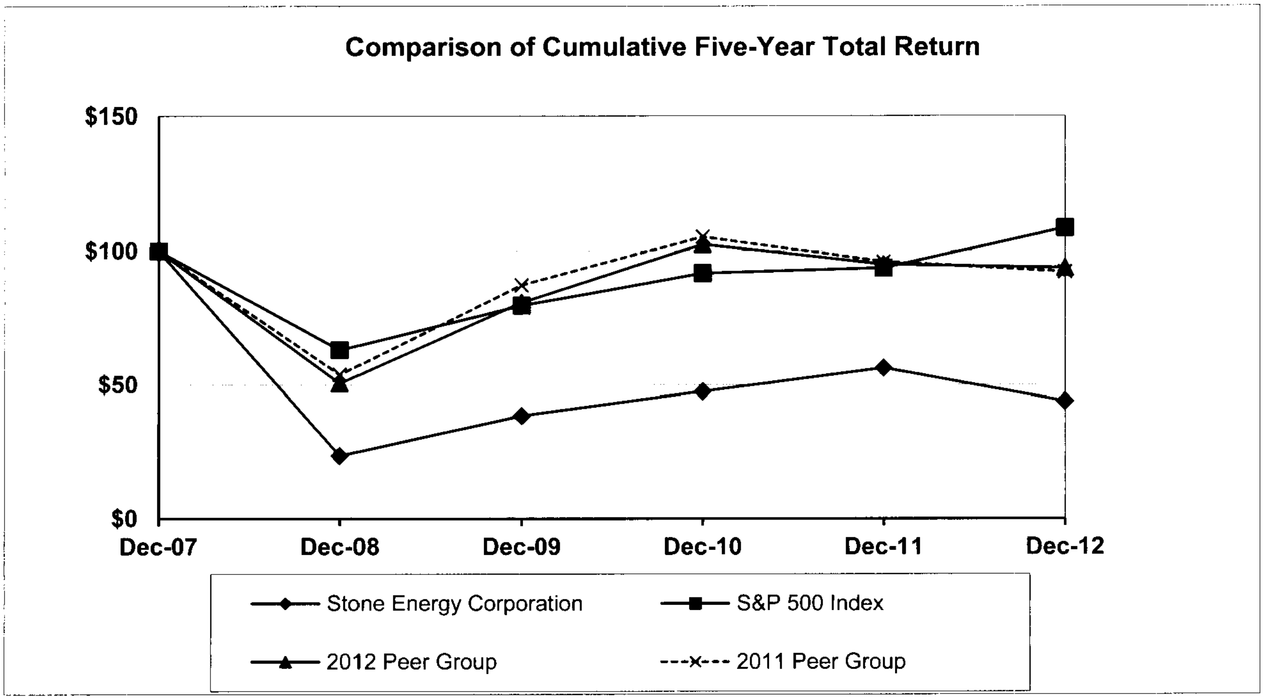
Equity Compensation Plan Information

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 Standard & Poor's 500 Stock Index ("S&P 500 Index") and the Peer Group (as defined below) on December 31, 2007 at $46.91 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	2012 Peer Group	2011 Peer Group	S&P 500 Index
12/31/08	23.49	50.58	53.80	63.00
12/31/09	38.48	80.77	87.30	79.67
12/31/10	47.52	102.46	105.30	91.68
12/31/11	56.24	94.89	95.89	93.61
12/31/12	43.74	93.66	92.18	108.59

The companies that comprised our Peer Group in 2012 were: ATP Oil & Gas Corporation, Cabot Oil & Gas Corporation, Callon Petroleum Company, Carrizo Oil & Gas, Inc., Cimarex Energy Company, Comstock Resources, Inc., Denbury Resources Inc., Energy Partners, Ltd., Energy XXI (Bermuda) Limited, Exco Resources Inc., McMoRan Exploration Company, Newfield Exploration Company, Petroleum Development Corporation, PetroQuest Energy, Inc., Plains Exploration & Production Company, Range Resources Corporation, SM Energy Company, Swift Energy Company, W&T Offshore, Inc. and Whiting Petroleum Corporation. Plains Exploration & Production Company replaced Petrohawk Energy Corporation after Petrohawk Energy Corporation was acquired by BHP Billiton in August 2011.

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 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 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act.

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, 2012. 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."** The information included in this table for the years ended December 31, 2009 and 2008 includes the effects of corrections on the previously reported financial statements.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Statement of Operations Data:	(In thousands, except per share amounts)				
Operating revenue:					
Oil production	$761,304	$663,958	$417,948	$438,942	$461,050
Gas production	134,739	170,611	210,686	272,353	336,665
Natural gas liquids production	48,498	29,996	27,473	-	-
Other operational income	3,520	3,938	5,916	4,326	5,989
Derivative income, net	3,428	1,418	3,265	3,061	3,327
Total operating revenue	951,489	869,921	665,288	718,682	807,031
Operating expenses:					
Lease operating expenses	215,003	175,881	150,212	156,786	171,107
Transportation, processing and gathering expenses	21,782	8,958	7,218	-	-
Other operational expenses	267	2,149	5,579	11,798	-
Production taxes	10,015	9,380	5,808	7,920	7,990
Depreciation, depletion and amortization	344,365	280,020	248,201	259,639	288,384
Write-down of oil and gas properties	-	-	-	508,989	1,324,327
Goodwill impairment	-	-	-	-	465,985
Accretion expense	33,331	30,764	34,469	39,306	17,392
Salaries, general and administrative expenses	54,648	40,169	42,759	41,367	43,504
Incentive compensation expense	8,113	11,600	5,888	6,402	2,315
Total operating expenses	687.524	558,921	500,134	1,032,207	2,321,004
Income (loss) from operations	263,965	311,000	165,154	(313,525)	(1,513,973)
Other (income) expenses:					
Interest expense	30,375	9,289	12,192	21,361	13,243
Interest income	(600)	(420)	(1,464)	(528)	(11,250)
Other income	(1,805)	(1,942)	(776)	(36)	189
Loss on early extinguishment of debt	1,972	607	1,820	-	-
Other expense	-	-	671	508	-
Total other expenses	29,942	7,534	12,443	21,305	2,182
Net income (loss) before income taxes	234,023	303,466	152,711	(334,830)	(1,516,155)
Income tax provision (benefit)	84,597	109,134	56,282	(116,559)	(369,146)
Net income (loss)	149,426	194,332	96,429	(218,271)	(1,147,009)
Net income (loss) attributable to non-controlling interest	-	-	-	27	(77)
Net income (loss) attributable to Stone Energy Corp.	$149,426	$194,332	$96,429	($218,298)	($1,146,932)
Earnings and dividends per common share:					
Basic earnings (loss) per share	$3.03	$3.97	$1.99	($4.97)	($35.89)
Diluted earnings (loss) per share	$3.03	$3.97	$1.99	($4.97)	($35.89)
Cash dividends declared per share	-	-	-	-	-
Cash Flow Data:					
Net cash provided by operating activities	$509,749	$570,850	$424,794	$507,787	$522,478
Net cash used in investing activities	(568,688)	(679,250)	(374,088)	(316,079)	(1,357,907)
Net cash provided by (used in) financing activities	300,014	39,895	(13,043)	(190,552)	428,440
Balance Sheet Data (at end of period):					
Working capital (deficit)	$300,348	($13,282)	$30,382	$26,137	$123,339
Oil and gas properties, net	2,182,095	1,875,048	1,397,809	1,185,709	1,628,170
Total assets	2,776,431	2,165,751	1,679,090	1,454,242	2,109,852
Long-term debt, less current potion	914,126	620,000	575,000	575,000	825,000
Stone Energy Corporation stockholders' equity	872,133	667,829	430,357	325,659	577,391

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, 2012. 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."** Certain 2011 and 2010 amounts have been changed from amounts previously presented to conform to the current presentation.

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. 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. We have expanded our reserve base outside of the conventional shelf of the GOM and into the more prolific reserve basins of the GOM deep water and Gulf Coast deep gas as well as onshore oil and gas shale opportunities, including the Marcellus Shale in Appalachia. See **"Item 1. Business – Strategy and Operational Overview."**

2012 Significant Events.

Diversification Strategy – In 2012, we had continued progress in our diversification strategy, resulting in a reserve mix of 44% Appalachia, 34% Deep Water, and 22% Conventional Shelf/Deep Gas on a volume equivalent basis. Additionally, our programs in Appalachia, deep water and deep gas all generated increased reserve volumes in 2012, resulting in company-wide reserve growth of over 20% from 2011. Our average reserve life has grown from 5.2 years in 2009 to approximately 8.5 years currently.

Issuance of 2017 Convertible Notes – On March 6, 2012, we issued in a private offering $300 million in aggregate principal amount of 1¾% Senior Convertible Notes due 2017. The net proceeds from the offering after deducting fees and expenses totaled $291.1 million. The notes are convertible into cash, shares of our common stock or a combination of cash and shares of our common stock, at our election, based on an initial conversion rate of 23.4449 shares of our common stock per $1,000 principal amount of 2017 Convertible Notes, which corresponds to an initial conversion price of approximately $42.65 per share of our common stock. In connection with the offering, we entered into convertible note hedge transactions in respect of our common stock and entered into separate warrant transactions at a higher strike price of $55.91, subject to certain adjustments. The net proceeds from the offering and the proceeds from the warrant transactions were used to fund the cost of the convertible note hedge transactions, to repay outstanding borrowings under our bank credit facility and to fund capital expenditures. The remaining proceeds will be used for general corporate purposes.

Issuance of 2022 Senior Notes – On November 8, 2012, we completed a public offering of $300 million aggregate principal amount of 7½% Senior Notes due 2022. The net proceeds from the offering after deducting fees and expenses totaled $293.2 million. Approximately $204.4 million of the net proceeds from the offering were used to fund the tender offer and consent solicitation and redemption of our outstanding 6¾% Senior Subordinated Notes due 2014 (the "2014 Notes"). The remaining proceeds will be used for general corporate purposes. As of December 31, 2102, we had approximately $279.5 million of cash on hand.

2013 Outlook.

Our 2013 capital expenditure budget is approximately $650 million. This figure compares with a $625 million capital budget for 2012 and excludes material acquisitions and capitalized salaries, general and administrative expenses and interest. The budget is spread across our major areas of investment with approximately 29% allocated to the deep water, 8% allocated to deep gas projects, 27% allocated to the GOM conventional shelf, 33% allocated to the Marcellus Shale and 3% allocated to onshore exploration projects. The allocation of capital across the various areas is subject to change based on several factors including permitting times, rig availability, non-operator decisions, farm-in opportunities and commodity pricing.

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 has been difficult to obtain for some time. We have narrowed our insurance coverage to selected properties, increased our deductibles and are assuming more hurricane related risk in the environment of rising insurance rates. Significant hurricane impacts could include reductions and/or deferrals of future oil and natural gas production and revenues, increased lease operating expenses for evacuations and repairs and possible acceleration of plugging and abandonment costs.

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 OCS, 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."**

Deep Water Operations – With our acquisition of interests in the Pompano field, we are now operating two significant properties in the deep water of the GOM. Operations in the deep water can result in increased operational risks as has been demonstrated by the Deepwater Horizon disaster in 2010. Despite technological advances since this disaster, liabilities for environmental losses, personal injury and loss of life and significant regulatory fines in the event of a disaster could be well in excess of insured amounts and result in significant current losses on our statement of operations as well as going concern issues.

Earnings Per Share – On March 6, 2012, we issued \$300 million of 2017 Convertible Notes. These notes are convertible into cash, shares of our common stock or a combination thereof at our election. Current accounting standards require us to use the treasury method for determining potential dilution in our diluted earnings per share computation since it is management's intention to settle the principal in cash. However, if due to changes in facts and circumstances beyond our control such intention were to change, or it becomes probable that we will be unable to settle the principal in cash, we could be required to change our methodology for determining diluted earnings per share to the if-converted method. The if-converted method would result in a substantial dilutive effect on diluted earnings per share when compared to the treasury method.

Liquidity and Capital Resources

At February 21, 2013, we had \$379.0 million of availability under our bank credit facility and cash on hand of approximately \$315.0 million. Our capital expenditure budget for 2013 has been set at \$650 million, which excludes material acquisitions and capitalized salaries, general and administrative expenses and interest. Based on our outlook of commodity prices and our estimated production, we expect our 2013 capital expenditures to exceed our cash flow from operating activities. We intend to finance our capital expenditure budget with cash flow from operating activities and cash on hand.

Cash Flow and Working Capital. Net cash flow from operating activities totaled \$509.7 million during the year ended December 31, 2012 compared to \$570.9 million and \$424.8 million during the years ended December 31, 2011 and 2010, respectively.

Net cash used in investing activities totaled \$568.7 million during the year ended December 31, 2012, which primarily represents our investment in oil and natural gas properties of \$555.9 million and our investment in fixed and other assets of \$13.4 million. Net cash used in investing activities totaled \$679.3 million during the year ended December 31, 2011, which primarily represents our investment in oil and natural gas properties of \$764.9 million offset by proceeds from the sale of oil and natural gas properties of \$87.9 million. Approximately \$270.4 million of the investment in oil and gas properties in 2011 related to leasehold acquisitions and the acquisition of producing properties. Net cash used in investing activities totaled \$374.1 million during the year ended December 31, 2010, which primarily represents our investment in oil and natural gas properties of \$401.8 million offset by proceeds from the sale of oil and natural gas properties of \$31.6 million.

Net cash provided by financing activities totaled \$300.0 million during the year ended December 31, 2012. In 2012, we received \$291.1 million of net proceeds from the issuance of our 2017 Convertible Notes and \$40.1 million of proceeds from the Sold Warrants, and used \$70.8 million for the cost of the Purchased Call Options (see **Notes to Consolidated Financial Statements – NOTE 11 – Long-Term Debt**). Additionally, we received \$293.2 million of net proceeds from the issuance of our 2022 Notes. During 2012, we used \$200.7 million for the redemption of our 2014 Notes. During the year ended December 31, 2012, we had \$25.0 million of borrowings and \$70.0 million of repayments of borrowings under our bank credit facility. Net cash provided by financing activities totaled \$39.9 million for the year ended December 31, 2011, which primarily represents borrowings net of repayments under our bank credit facility of \$45.0 million, less \$4.0 million of deferred financing costs associated with our new bank credit facility and \$2.6 million of net payments for share based compensation. Net cash used in financing activities totaled \$13.0 million for the year ended December 31, 2010, which primarily represents repayments of borrowings under our bank credit facility of \$175 million, the redemption of our 8¼% Senior Subordinated Notes due 2011 (the "2011 Notes") of \$200.5 million, net of proceeds from the public offering of our 2017 Notes of approximately \$375 million less \$11.5 million of deferred financing costs.

We had working capital at December 31, 2012 of $300.3 million. Included in working capital at December 31, 2012 is a portion of the proceeds received from the issuance of the 2017 Convertible Notes and the 2022 Notes.

Capital Expenditures. During the year ended December 31, 2012, additions to oil and gas property costs of $642.5 million included $102.8 million of lease and property acquisition costs, $25.0 million of capitalized salaries, general and administrative expenses (inclusive of incentive compensation) and $37.7 million of capitalized interest. These investments were financed with cash flow from operating activities and the net proceeds from the 2017 Convertible Notes.

Bank Credit Facility. On April 26, 2011, we entered into an amended and restated revolving credit facility totaling $700 million (subject to borrowing base limitations) through a syndicated bank group, replacing our previous facility. Our bank credit facility matures on April 26, 2015. On October 22, 2012, our borrowing base under our bank credit facility was reaffirmed at $400 million. As of December 31, 2012 and February 21, 2013, we had no outstanding borrowings under our bank credit facility and letters of credit totaling $21.0 million had been issued pursuant to the bank credit facility, leaving $379.0 million of availability under the facility. Our bank credit facility is guaranteed by our only subsidiary, Stone Energy Offshore, L.L.C. ("Stone Offshore").

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 our option, loans under the bank 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 bank 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 consolidated EBITDA to consolidated Net Interest Expense, as defined in the credit agreement, for the preceding four quarterly periods of not less than 3.0 to 1. As of December 31, 2012, our debt to EBITDA Ratio was 1.55 to 1 and our EBITDA to consolidated Net Interest Expense Ratio was approximately 21.56 to 1. In addition, the bank 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. These covenants also restrict our ability to prepay other indebtedness under certain circumstances.

7½% Senior Notes due 2022. On November 8, 2012, we completed the public offering of $300 million aggregate principal amount of our 2022 Notes. The net proceeds from the offering after deducting underwriting discounts, commissions, fees and expenses totaled $293.2 million. Approximately $204.4 million of the net proceeds from the offering were used to fund the tender offer and consent solicitation and redemption of our outstanding 2014 Notes. The remaining proceeds will be used for general corporate purposes.

6¾% Senior Subordinated Notes due 2014. In November 2012, we used proceeds from the 2022 Notes offering to purchase our 2014 Notes pursuant to a tender offer and consent solicitation. In December 2012, the remaining 2014 Notes were redeemed in full. The total cost of the redemption was $204.4 million, which included $200.7 million to redeem the notes plus accrued and unpaid interest of $3.7 million. The transaction resulted in a charge to earnings of $2.0 million in 2012.

1¾% Senior Convertible Notes due 2017. On March 6, 2012, we issued in a private offering $300 million in aggregate principal amount of 2017 Convertible Notes to qualified institutional buyers pursuant to Rule 144A under the Securities Act. The net proceeds from the sale of the 2017 Convertible Notes were $291.1 million, after deducting fees and expenses. The 2017 Convertible Notes mature on March 1, 2017, unless earlier converted or repurchased. We may not redeem the 2017 Convertible Notes at our option prior to the maturity date.

The 2017 Convertible Notes are convertible into cash, shares of our common stock or a combination of cash and shares of our common stock, at our election, based on an initial conversion rate of 23.4449 shares of our common stock per $1,000 principal amount of 2017 Convertible Notes, which corresponds to an initial conversion price of approximately $42.65 per share of our common stock. On December 31, 2012, our closing share price was $20.52. The conversion rate, and thus the conversion price, may be adjusted under certain circumstances as described in the indenture related to the 2017 Convertible Notes. Upon conversion, we will be obligated to pay or deliver, as the case may be, cash, shares of our common stock or a combination of cash and shares of our common stock, at our election. Prior to December 1, 2016, the 2017 Convertible Notes will be convertible only upon the occurrence of certain events and during certain periods, and thereafter, at any time until the second scheduled trading day immediately preceding the maturity date.

In connection with the offering, we entered into convertible note hedge transactions in respect of our common stock. These convertible note hedge transactions are expected to reduce the potential dilution upon future conversion of the 2017 Convertible Notes. In addition, we entered into separate warrant transactions at a higher strike price. The warrant transactions could separately have a dilutive effect to the extent that the market value per share of our common stock exceeds the applicable strike price of the warrants.

We applied a portion of the net proceeds of $291.1 million from the sale of the 2017 Convertible Notes and the proceeds from the warrant transactions of $40.1 million to fund the cost of the convertible note hedge transactions of $70.8 million. We also used a portion of the net proceeds to repay $70 million of outstanding 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, 2012, 300,000 shares had been repurchased under this program at a total cost of approximately $7.1 million, or an average price of $23.57 per share. No shares were repurchased during the years ended December 31, 2012, 2011 or 2010.

Hedging. See **"Item 7A. Quantitative and Qualitative Disclosures 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, 2012 (in thousands):

	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**
Contractual Obligations and Commitments:					
1¾% Senior Convertible Notes due 2017	$300,000	$ -	$ -	$300,000	$ -
8⅝% Senior Notes due 2017	375,000	-	-	375,000	-
7½% Senior Notes due 2022	300,000	-	-	-	300,000
Interest and commitment fees (1)	383,975	62,015	121,546	87,914	112,500
Asset retirement obligations including accretion	878,551	68,142	233,123	100,054	477,232
Rig commitments	33,712	33,712	-	-	-
Seismic data commitments (2)	18,587	11,087	7,500	-	-
Operating lease obligations	2,237	612	1,080	463	82
Total Contractual Obligations and Commitments	$2,292,062	$175,568	$363,249	$863,431	$889,814

(1) Includes interest payable on the 2017 Notes, 2022 Notes and 2017 Convertible Notes. Assumes 0.5% fee on unused commitments under the bank credit facility.
(2) Represents pre-commitments for seismic data purchases.

Safety Performance

We measure our safety performance based on the total recordable incident rate ("TRIR"), which is the number of safety incidents per 200,000 man-hours worked for employees and certain contractors. All onshore safety incidents are reported to the Occupational Safety and Health Administration ("OSHA") and are tracked on OSHA Form 301. All offshore safety incidents are reported to the BOEM. Our TRIR is provided to the BOEM as part of a voluntary program for safety monitoring in the GOM. Our TRIR for the last three calendar years was as follows:

Year Ended December 31,	TRIR Performance	TRIR Goal
2012	0.45	0.55
2011	0.33	0.65
2010	0.51	0.65

Our safety initiative includes formal programs for observation and reporting of at-risk and safe behavior in and away from the work place, employee awards for results and observations, employee participation in offsite training programs and internal safety audits. We have an annual cash incentive compensation plan that includes a safety component based on our annual TRIR.

Results of Operations

2012 Compared to 2011. The following table sets forth certain 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,			
	2012	2011	Variance	% Change
Production:				
Oil (MBbls)	7,135	6,427	708	11%
Natural gas (MMcf)	42,569	38,466	4,103	11%
Natural gas liquids (MBbls)	1,163	506	657	130%
Oil, natural gas and NGLs (MMcfe)	92,357	80,064	12,293	15%
Average prices: (1)				
Oil (per Bbl)	$106.70	$103.31	$3.39	3%
Natural gas (per Mcf)	3.17	4.44	(1.27)	(29%)
Natural gas liquids (per Bbl)	41.70	59.28	(17.58)	(30%)
Oil, natural gas and NGLs (per Mcfe)	10.23	10.80	(0.57)	(5%)
Expenses (per Mcfe):				
Lease operating expenses	$2.33	$2.20	$0.13	6%
Salaries, general and administrative expenses (2)	0.59	0.50	0.09	18%
DD&A expense on oil and gas properties	3.69	3.45	0.24	7%
Estimated Proved Reserves at December 31:				
Oil (MBbls)	44,918	45,655	(737)	(2%)
Natural gas (MMcf)	395,374	325,479	69,895	22%
Natural gas liquids (MBbls)	18,066	4,405	13,661	310%
Oil, natural gas and NGLs (MMcfe)	773,285	625,839	147,446	24%

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

Net Income. For the year ended December 31, 2012, we reported net income totaling $149.4 million, or $3.03 per share, compared to net income for the year ended December 31, 2011 of $194.3 million, or $3.97 per share. All per share amounts are on a diluted basis.

In the first quarter of 2012, we began reporting NGL volumes and revenues separately from gas volumes. Historically, we reported "wet" gas volumes, which included entrained liquids. We now report NGLs and "dry" gas (shrunk for removal of liquids) volumes. Production volumes, revenues and prices for the year ended December 31, 2011 have been reclassified to conform to the current presentation.

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

Production. During the year ended December 31, 2012, total production volumes increased to 92.4 Bcfe compared to 80.1 Bcfe produced during the comparable 2011 period, representing a 15% increase. Oil production during the year ended December 31, 2012 totaled approximately 7,135,000 Bbls compared to 6,427,000 Bbls produced during the year ended December 31, 2011; natural gas production totaled 42.6 Bcf during the year ended December 31, 2012 compared to 38.5 Bcf produced during the comparable period of 2011; and NGL production during the year ended December 31, 2012 totaled approximately 1,163,000 Bbls compared to 506,000 Bbls produced during the comparable period of 2011. The increase in NGL production resulted from our liquids rich Pompano and Appalachia gas streams coming on line. Production commenced from our deep water Pyrenees well at Garden Banks 293 during the first quarter of 2012. Included in production for the year ended December 31, 2012 is production from our Pompano field, which was acquired in December 2011.

Prices. Prices realized during the year ended December 31, 2012 averaged $106.70 per Bbl of oil, $3.17 per Mcf of natural gas and $41.70 per Bbl of NGLs, or 5% lower, on an Mcfe basis, than 2011 average realized prices of $103.31 per Bbl of oil, $4.44 per Mcf of natural gas and $59.28 per Bbl of NGLs. 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 year ended December 31, 2012, effective hedging transactions increased our average realized natural gas price by $0.52 per Mcf and increased our average realized oil price by $1.20 per Bbl. During the year ended December 31, 2011, effective hedging transactions increased our average realized natural gas price by $0.51 per Mcf and decreased our average realized oil price by $5.09 per Bbl.

Revenue. Oil, natural gas and NGL revenue increased 9% to $944.5 million during the year ended December 31, 2012 from $864.6 million during the year ended December 31, 2011. The increase was attributable to a 15% increase in production quantities on a gas equivalent basis, partially offset by a 5% decrease in average realized prices.

Expenses. Lease operating expenses for the years ended December 31, 2012 and 2011 totaled $215.0 million and $175.9 million, respectively. The increase in lease operating expenses in 2012 was primarily attributable to the impact of expenses at our Pompano field, which was acquired in December 2011, as well as seasonal major maintenance projects.

Transportation, processing and gathering expenses during the years ended December 31, 2012 and 2011 totaled $21.8 million and $9.0 million, respectively. The increase resulted from our liquids rich Pompano and Appalachia gas streams coming on line in early 2012.

For the year ended December 31, 2011, other operational expenses of $2.1 million included $0.7 million for the settlement of litigation associated with an expensed operation in the first quarter of 2011, a $0.3 million loss on the sale of non-dedicated tubular inventory and $1.1 million of miscellaneous inventory charges.

Depreciation, depletion and amortization ("DD&A") expense on oil and gas properties for the year ended December 31, 2012 totaled $341.1 million, or $3.69 per Mcfe, compared to DD&A expense of $276.5 million, or $3.45 per Mcfe, for the year ended December 31, 2011. The increase in DD&A expense on a unit basis in 2012 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.

For the years ended December 31, 2012 and 2011, salaries, general and administrative ("SG&A") expenses (exclusive of incentive compensation) totaled $54.6 million and $40.2 million, respectively. The increase in SG&A expenses in 2012 was primarily the result of increased staffing and compensation adjustments (including stock based compensation) and a management fee of $1.0 million for transition services related to our Pompano acquisition. In 2011, there was a $3.9 million credit to SG&A expenses, including previously unaccrued insurance proceeds.

For the years ended December 31, 2012 and 2011, incentive compensation expense totaled $8.1 million and $11.6 million, respectively. These amounts related to incentive compensation bonuses calculated based on the achievement of certain strategic objectives for each fiscal year.

Interest expense for the year ended December 31, 2012 totaled $30.4 million, net of $37.7 million of capitalized interest, compared to interest expense of $9.3 million, net of $42.0 million of capitalized interest, during the year ended December 31, 2011. The increase in interest expense is primarily the result of interest associated with the 2017 Convertible Notes issued on March 6, 2012.

2011 Compared to 2010. The following table sets forth certain 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,			
	2011	2010	Variance	% Change
Production:				
Oil (MBbls)	6,427	5,714	713	12%
Natural gas (MMcf)	38,466	41,168	(2,702)	(7%)
Natural gas liquids (MBbls)	506	574	(68)	(12%)
Oil, natural gas and NGLs (MMcfe)	80,064	78,896	1,168	1%
Average prices: (1)				
Oil (per Bbl)	$103.31	$73.14	$30.17	41%
Natural gas (per Mcf)	4.44	5.12	(0.68)	(13%)
Natural gas liquids (per Bbl)	59.28	47.86	11.42	24%
Oil, natural gas and NGLs (per Mcfe)	10.80	8.32	2.48	30%
Expenses (per Mcfe):				
Lease operating expenses	$2.20	$1.90	$0.30	16%
Salaries, general and administrative expenses (2)	0.50	0.54	(0.04)	(7%)
DD&A expense on oil and gas properties	3.45	3.08	0.37	12%
Estimated Proved Reserves at December 31:				
Oil (MBbls)	45,655	33,203	12,452	38%
Natural gas (MMcf)	325,479	274,705	50,774	18%
Natural gas liquids (MBbls)	4,405	-	4,405	N/A
Oil, natural gas and NGLs (MMcfe)	625,839	473,923	151,916	32%

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

Net Income. For the year ended December 31, 2011, we reported net income totaling $194.3 million, or $3.97 per share, compared to net income for the year ended December 31, 2010 of $96.4 million, or $1.99 per share. All per share amounts are on a diluted basis.

In the first quarter of 2012, we began reporting NGL volumes and revenues separately from gas volumes. Historically, we reported "wet" gas volumes, which included entrained liquids. We now report NGLs and "dry" gas (shrunk for removal of liquids) volumes. Production volumes, revenues and prices for the years ended December 31, 2011 and 2010 have been reclassified to conform to the current presentation.

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

Production. During the year ended December 31, 2011, total production volumes increased to 80.1 Bcfe compared to 78.9 Bcfe produced during the comparable 2010 period. Oil production during the year ended December 31, 2011 totaled approximately 6,427,000 Bbls compared to 5,714,000 Bbls produced during the year ended December 31, 2010; natural gas production totaled 38.5 Bcf during the year ended December 31, 2011 compared to 41.2 Bcf produced during the comparable period of 2010; and NGL production during the year ended December 31, 2011 totaled approximately 506,000 Bbls compared to 574,000 Bbls produced during the comparable period of 2010. The increase in oil production volumes was primarily due to increases in production at our Mississippi Canyon Block 109 and Ship Shoal Block 113 fields where we had development operations. The decrease in gas production volumes was primarily due to natural production declines.

Prices. Prices realized during the year ended December 31, 2011 averaged $103.31 per Bbl of oil, $4.44 per Mcf of natural gas and $59.28 per Bbl of NGLs, or 30% higher, on an Mcfe basis, than 2010 average realized prices of $73.14 per Bbl of oil, $5.12 per Mcf of natural gas and $47.86 per Bbl of NGLs. 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 year ended December 31, 2011, effective hedging transactions increased our average realized natural gas price by $0.51 per Mcf and decreased our average realized oil price by $5.09 per Bbl. During the year ended December 31, 2010, effective hedging transactions increased our average realized natural gas price by $0.94 per Mcf and decreased our average realized oil price by $5.09 per Bbl.

Revenue. Oil, natural gas and NGL revenue increased 32% to $864.6 million during the year ended December 31, 2011 from $656.1 million during the year ended December 31, 2010. The increase was primarily due to a 41% increase in average realized oil prices along with a 12% increase in oil production volumes, partially offset by a decline in average realized gas prices and gas production volumes.

Expenses. Lease operating expenses for the years ended December 31, 2011 and 2010 totaled $175.9 million and $150.2 million, respectively. On a unit of production basis, lease operating expenses were $2.20 per Mcfe and $1.90 per Mcfe for the years ended December 31, 2011 and 2010, respectively. The increase in lease operating expenses in 2011 was primarily attributable to increased platform and well maintenance.

For the year ended December 31, 2011, other operational expenses of $2.1 million included $0.7 million for the settlement of litigation associated with an expensed operation in the first quarter of 2011, a $0.3 million loss on the sale of non-dedicated tubular inventory and $1.1 million of miscellaneous inventory charges. For the year ended December 31, 2010, other operational expenses of $5.6 million included a $2.2 million loss on the sale of non-dedicated tubular inventory and a total of $3.3 million of charges related to a delay in the drilling of the second well in our Amberjack drilling program as a result of the deep water drilling moratorium.

DD&A expense on oil and gas properties for the year ended December 31, 2011 totaled $276.5 million, or $3.45 per Mcfe, compared to DD&A expense of $242.7 million, or $3.08 per Mcfe, for the year ended December 31, 2010. The increase in DD&A expense in 2011 on a unit basis was primarily 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. The average unit cost of the Pompano field deep water assets had a minimal impact on the DD&A rate because the acquisition occurred late in the year.

For the years ended December 31, 2011 and 2010, incentive compensation expense totaled $11.6 million and $5.9 million, respectively. These amounts related to incentive compensation bonuses calculated based on the achievement of certain strategic objectives for each fiscal year.

Interest expense for the year ended December 31, 2011 totaled $9.3 million, net of $42.0 million of capitalized interest, compared to interest expense of $12.2 million, net of $30.8 million of capitalized interest, during the year ended December 31, 2010. The decrease in interest expense is primarily the result of an increase in the amount of interest capitalized as a part of the cost of oil and gas properties.

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 Estimates

Fair Value Measurements. U.S. Generally Accepted Accounting Principles ("GAAP"), as codified, establish a framework for measuring fair value and require certain disclosures about fair value measurements. There is an established fair value hierarchy that 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, 2012, 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 marketable securities. Additionally, fair value concepts were applied in recording the acquisition of various deep water assets in 2012 and 2011 and the acquisition of an office building in 2012.

Business Combinations. Our acquisitions in 2012 and 2011 of various deep water assets were accounted for according to the guidance provided in Accounting Standards Codification ("ASC") 805, Business Combinations, which requires application of the acquisition method. This methodology requires the recordation of net assets acquired and consideration transferred at fair value. Differences between the net fair value of assets acquired and consideration transferred are recorded as goodwill or a bargain purchase gain.

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 evaluated properties 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 expense using the units of production ("UOP") method. Under the UOP method, the quarterly provision for DD&A expense 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 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 expense. 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 the full cost method, DD&A expense is computed on cost centers represented by entire countries while under the successful efforts method 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, 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. Estimated future net cash flows from proved reserves are calculated based on a 12-month average pricing assumption.

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 U.S. GAAP 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 reserve 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;
- estimates of fair value in business combinations;
- current and deferred 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

None.

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 income per share for 2012 would have decreased approximately $1.22 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 2013, 2014 and 2015 oil and natural gas production from the Gulf Coast Basin. Some of our fixed-price oil swap settlements are based on an average of the NYMEX closing price for West Texas Intermediate during the entire calendar month, and some are based on the average of the ICE closing price for Brent crude oil during the entire calendar month. Our fixed-price gas swap settlements are based on the NYMEX price for the last day of a respective contract 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 fixed-price swap contracts are with The Toronto-Dominion Bank, Barclays Bank PLC, BNP Paribas, The Bank of Nova Scotia, Bank of America and Natixis.

The following table illustrates our hedging positions for calendar years 2013, 2014 and 2015 as of February 21, 2013:

Fixed-Price Swaps
NYMEX (except where noted)

	Natural Gas		Oil	
	Daily Volume (MMBtus/d)	**Swap Price ($)**	**Daily Volume (Bbls/d)**	**Swap Price ($)**
2013	10,000	4.000	1,000	92.80
2013	10,000	5.270	2,000*	94.05
2013	10,000	5.320	1,000	94.45
2013			1,000	94.60
2013			1,000	97.15
2013			1,000	101.53
2013			1,000	103.00
2013			1,000	103.15
2013			1,000	104.25
2013			1,000	104.47
2013			1,000	104.50
2013			1,000 †	107.30
2014	10,000	4.000	1,000	90.06
2014	10,000	4.040	1,000	93.55
2014	10,000	4.105	1,000	94.00
2014	10,000	4.250	1,000	98.00
2014			1,000	98.30
2014			1,000	99.65
2014			1,000 †	103.30
2015	10,000	4.005	1,000	90.00
2015	10,000	4.220		
2015	10,000	4.255		

† Brent oil contract
* January through June

We believe these positions have hedged approximately 39% of our estimated 2013 production from estimated proved reserves, 34% of our estimated 2014 production from estimated proved reserves and 18% of our estimated 2015 production from estimated proved reserves.

Interest Rate Risk. We had total debt outstanding of $914.1 million at December 31, 2012, all of which bears interest at fixed rates. The $914.1 million of fixed-rate debt is comprised of $239.1 million ($300 million face value) of 2017 Convertible Notes, $375 million of 2017 Notes and $300 million of 2022 Notes.

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 its 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

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2012 at the reasonable assurance level.

Changes in Internal Controls Over Financial Reporting

There has not been any change in our internal control over financial reporting that occurred during the quarter ended December 31, 2012 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 Exchange Act. 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, 2012. 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, 2012. Ernst and Young LLP, an independent public accounting firm, has issued its report on the company's internal control over financial reporting as of December 31, 2012.

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, 2012, 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, 2012, 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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2012 and our report dated February 27, 2013 expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
February 27, 2013

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The following table sets forth information regarding the names, ages (as of February 21, 2013) 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.

Name	Age	Position
David H. Welch	64	President, Chief Executive Officer and Director
Kenneth H. Beer	55	Executive Vice President and Chief Financial Officer
Andrew L. Gates, III	65	Senior Vice President, General Counsel and Secretary
Kevin G. Hurst	53	Vice President – GOM Shelf/Deep Gas
E. J. Louviere	64	Senior Vice President – Land
J. Kent Pierret	57	Senior Vice President, Chief Accounting Officer and Treasurer
Keith A. Seilhan	46	Vice President – Deep Water
Richard L. Toothman, Jr.	48	Vice President – Appalachia
Paul K. Wieg	54	Vice President – Exploration and Business Development
Florence M. Ziegler	52	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 Executive Vice President and Chief Financial Officer in January 2011. Previously, he served as Senior Vice President and Chief Financial Officer since August 2005. Prior to joining Stone, he 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 & Company 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.

Kevin G. Hurst was named Vice President – GOM Shelf/Deep Gas on February 1, 2013. He previously served as General Manager of Operations/GOM Production from January 2012 through February 1, 2013. He served as Operations Manager – GOM Production from January 2011 through January 2012 and Production Manager from December 2007 through January 2011. Prior to joining Stone in 2007, he worked for MODEC, LLC as the General Manager for FPSO/FSO Operations. Mr. Hurst has also worked for Southern Natural Gas Company/El Paso Energy Company and worked for 16 years for Arco serving in various capacities.

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.

Keith S. Seilhan was named Vice President – Deep Water on February 1, 2013. He previously served as Deep Water Projects Manager since joining Stone in July 2012. Prior to joining Stone, Mr. Seilhan filled various senior leadership roles for Amoco and BP over his 21 year career. In his final year with BP, he filled the role as BP's Incident Commander on the Deepwater Horizon Incident in 2010 and also worked as an Emergency Response Consultant with The Response Group for 1-1/2 years. He has been an Asset Manager and Operations Manager for Deep Water Assets, Operations Director for Gulf of Mexico and the Organizational Capability Manager. Mr. Seilhan received a "Wells Notice," dated January 25, 2013, from the Staff of the SEC indicating its intent to recommend to the SEC that it bring a civil injunctive action against Mr. Seilhan alleging that he violated Section 17(a) of the

Securities Act, Section 10(b) of the Exchange Act and Rule 10b-5 thereunder. We have also been advised that Mr. Seilhan is a target of an investigation by the Department of Justice ("DOJ"). The SEC's inquiry and the DOJ's investigation relate to activities prior to Mr. Seilhan's employment with the Company and are not directed at, and do not concern, the Company or any other member of management or any member of the board.

Richard L. Toothman, Jr. was named Vice President – Appalachia in May 2010. Prior to joining Stone in May 2010, he was employed by CNX Gas Company in Bluefield, Virginia since August 2005 where he held two executive positions, VP Engineering and Technical Services and VP International Business. He also worked for Consol Energy and Conoco in prior years.

Paul K. Wieg was named Vice President – Exploration and Business Development on February 1, 2013. He previously served as Director of Geosciences/Deepwater Exploration Manager of Stone from January 2012 through February 1, 2013. He served as Director, Exploration and Geoscience Technology from January 2011 through January 2012 and Deepwater Exploration Manager from July 2010 through January 2011. Prior to joining Stone in 2010, Mr. Wieg was Deepwater Exploration Manager for Eni Petroleum's Gulf of Mexico business unit. He also served in various capacities for Dominion E&P, CNG, Shell Offshore, Inc. Pecten International and Exxon USA.

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.

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 2013 Annual Meeting of Stockholders to be held on May 23, 2013. 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 2013 Annual Meeting of Stockholders to be held on May 23, 2013.

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 2013 Annual Meeting of Stockholders to be held on May 23, 2013.

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 2013 Annual Meeting of Stockholders to be held on May 23, 2013.

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 2013 Annual Meeting of Stockholders to be held on May 23, 2013.

PART IV

ITEM 15. EXHIBITS, 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, 2012 and 2011
Consolidated Statement of Operations for the three years in the period ended December 31, 2012
Consolidated Statement of Comprehensive Income for the three years in the period ended December 31, 2012
Consolidated Statement of Cash Flows for the three years in the period ended December 31, 2012
Consolidated Statement of Changes in Stockholders' Equity for the three years in the period ended December 31, 2012
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 Consolidated Financial Statements or the notes thereto.

3. Exhibits:

3.1	Certificate of Incorporation of the Registrant, as amended on June 4, 1993, February 1, 2001 and February 19, 2002 (incorporated by reference to Exhibit 3.1 to the Registrant's Quarterly Report on Form 10-Q filed August 7, 2012 (File No.001-12074)).
3.2	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 filed May 21, 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 December 17, 2004 (File No. 001-12074)).
4.2	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 filed August 29, 2008 (File No. 001-12074)).
4.3	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 filed January 29, 2010 (File No. 001-12074)).
4.4	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 filed January 29, 2010 (File No. 001-12074)).
4.5	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 filed January 29, 2010 (File No. 001-12074)).

4.6	Indenture related to the 1¾% Senior Convertible Notes due 2017, dated as of March 6, 2012, among Stone Energy Corporation, Stone Energy Offshore, L.L.C. and The Bank of New York Mellon Trust Company, N.A., as trustee (including form of 1¾% Senior Convertible Senior Note due 2017) (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
4.7	Second Supplemental Indenture, dated as of November 6, 2012, to the Indenture, dated as of December 15, 2004, 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 4.1 to the Registrant's Current Report on Form 8-K filed November 8, 2012 (File No. 001-12074)).
4.8	Second Supplemental Indenture, dated as of November 8, 2012, to the Indenture, dated as of 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 filed November 8, 2012 (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	First Amendment to Stone Energy Corporation 2009 Amended and Restated Stock Incentive Plan (incorporated by reference to Exhibit 4.6 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011 (File No. 001-12074)).
†10.4	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)).
†10.5	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)).
†10.6	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)).
†10.7	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)).
†10.8	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)).
†10.9	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)).
†10.10	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)).

†10.11	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)).
10.12	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)).
10.13	$700,000,000 Third Amended and Restated Credit Agreement among Stone Energy Corporation as Borrower, Bank of America, N.A. as Administrative Agent and Issuing Bank, and the financial institutions named therein, dated April 26, 2011 (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-12074)).
10.14	Amendment No. 1 and Consent dated as of February 28, 2012 to the Third Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 5, 2012 (File No. 001-12074)).
10.15	Amendment No. 2 and Consent dated as of October 22, 2012 to the Third Amended and Restated Credit Agreement (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed October 22, 2012 (File No. 001-12074)).
10.16	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)).
10.17	Base Bond Hedge Confirmation dated as of February 29, 2012, by and between Stone Energy Corporation and Barclays Capital Inc., acting as agent for Barclays Bank PLC (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.18	Base Bond Hedge Confirmation dated as of February 29, 2012, by and between Stone Energy Corporation and Bank of America N.A. (incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.19	Additional Bond Hedge Confirmation dated as of March 2, 2012, by and between Stone Energy Corporation and Barclays Capital Inc., acting as agent for Barclays Bank PLC (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.20	Additional Bond Hedge Confirmation dated as of March 2, 2012, by and between Stone Energy Corporation and Bank of America N.A. (incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.21	Base Warrant Confirmation dated as of February 29, 2012, by and between Stone Energy Corporation and Barclays Capital Inc., acting as agent for Barclays Bank PLC (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.22	Base Warrant Confirmation dated as of February 29, 2012, by and between Stone Energy Corporation and Bank of America N.A. (incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.23	Additional Warrant Confirmation dated as of March 2, 2012, by and between Stone Energy Corporation and Barclays Capital Inc., acting as agent for Barclays Bank PLC (incorporated by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).

10.24	Additional Warrant Confirmation dated as of March 2, 2012, by and between Stone Energy Corporation and Bank of America N.A. (incorporated by reference to Exhibit 10.8 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.25	Amendment to Base Warrant Confirmation and Additional Warrant Confirmation dated March 5, 2012, by and between Stone Energy Corporation and Barclays Capital Inc., acting as agent for Barclays Bank PLC (incorporated by reference to Exhibit 10.9 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (File No. 001-12074)).
10.26	Amendment to Base Warrant Confirmation and Additional Warrant Confirmation dated March 5, 2012, by and between Stone Energy Corporation and Bank of America N.A. (incorporated by reference to Exhibit 10.10 to the Registrant's Current Report on Form 8-K filed March 6, 2012 (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.
**101.INS	XBRL Instance Document
**101.SCH	XBRL Schema Document
**101.CAL	XBRL Calculation Linkbase Document
**101.DEF	XBRL Definition Linkbase Document
**101.LAB	XBRL Label Linkbase Document
**101.PRE	XBRL Presentation Linkbase Document
*99.1	Report of Netherland, Sewell & Associates, Inc.

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* Filed or furnished herewith.

** Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

\# 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.

† Identifies management contracts and compensatory plans or arrangements.

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 27, 2013

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

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

Signature	Title	Date
/s/ David H. Welch David H. Welch	President, Chief Executive Officer and Director (principal executive officer)	February 27, 2013
/s/ Kenneth H. Beer Kenneth H. Beer	Executive Vice President and Chief Financial Officer (principal financial officer)	February 27, 2013
/s/ J. Kent Pierret J. Kent Pierret	Senior Vice President, Chief Accounting Officer and Treasurer (principal accounting officer)	February 27, 2013
/s/ George R. Christmas George R. Christmas	Director	February 27, 2013
/s/ B.J. Duplantis B.J. Duplantis	Director	February 27, 2013
/s/ Peter D. Kinnear Peter D. Kinnear	Director	February 27, 2013
/s/ John P. Laborde John P. Laborde	Director	February 27, 2013
/s/ Robert S. Murley Robert S. Murley	Director	February 27, 2013
/s/ Richard A. Pattarozzi Richard A. Pattarozzi	Director	February 27, 2013
/s/ Donald E. Powell Donald E. Powell	Director	February 27, 2013
/s/ Kay G. Priestly Kay G. Priestly	Director	February 27, 2013
/s/ Phyllis M. Taylor Phyllis M. Taylor	Director	February 27, 2013

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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, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, cash flows, and changes in stockholders' equity for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with U.S. generally accepted accounting principles.

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, 2012, 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 27, 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

New Orleans, Louisiana
February 27, 2013

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

Assets	December 31, 2012	December 31, 2011
Current assets:		
Cash and cash equivalents	$279,526	$38,451
Accounts receivable	167,288	118,139
Fair value of hedging contracts	39,655	25,177
Current income tax receivable	10,027	19,946
Deferred taxes	15,514	26,072
Inventory	4,207	4,643
Other current assets	3,626	791
Total current assets	519,843	233,219
Oil and gas properties, full cost method of accounting:		
Proved	7,244,466	6,648,168
Less: accumulated depreciation, depletion and amortization	(5,510,166)	(5,174,729)
Net proved oil and gas properties	1,734,300	1,473,439
Unevaluated	447,795	401,609
Other property and equipment, net of accumulated depreciation of $26,429 and $24,263, respectively	22,115	11,172
Fair value of hedging contracts	9,199	22,543
Other assets, net of accumulated depreciation and amortization of $6,438 and $5,911, respectively	43,179	23,769
Total assets	$2,776,431	$2,165,751
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable to vendors	$94,361	$102,946
Undistributed oil and gas proceeds	23,414	27,328
Accrued interest	18,546	14,059
Fair value of hedging contracts	149	11,122
Asset retirement obligations	66,260	62,676
Other current liabilities	16,765	28,370
Total current liabilities	219,495	246,501
Long-term debt	914,126	620,000
Deferred taxes	310,830	247,835
Asset retirement obligations	422,042	363,103
Fair value of hedging contracts	1,530	815
Other long-term liabilities	36,275	19,668
Total liabilities	1,904,298	1,497,922
Commitments and contingencies		
Stockholders' equity:		
Common stock, $.01 par value; authorized 100,000,000 shares; issued 48,392,552 and 48,076,860 shares, respectively	484	481
Treasury stock (16,582 shares, at cost)	(860)	(860)
Additional paid-in capital	1,386,475	1,338,565
Accumulated deficit	(542,799)	(692,225)
Accumulated other comprehensive income	28,833	21,868
Total stockholders' equity	872,133	667,829
Total liabilities and stockholders' equity	$2,776,431	$2,165,751

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,		
	2012	2011	2010
Operating revenue:			
Oil production	$761,304	$663,958	$417,948
Gas production	134,739	170,611	210,686
Natural gas liquids production	48,498	29,996	27,473
Other operational income	3,520	3,938	5,916
Derivative income, net	3,428	1,418	3,265
Total operating revenue	951,489	869,921	665,288
Operating expenses:			
Lease operating expenses	215,003	175,881	150,212
Transportation, processing and gathering expenses	21,782	8,958	7,218
Production taxes	10,015	9,380	5,808
Depreciation, depletion and amortization	344,365	280,020	248,201
Accretion expense	33,331	30,764	34,469
Salaries, general and administrative expenses	54,648	40,169	42,759
Incentive compensation expense	8,113	11,600	5,888
Other operational expenses	267	2,149	5,579
Total operating expenses	687,524	558,921	500,134
Income from operations	263,965	311,000	165,154
Other (income) expenses:			
Interest expense	30,375	9,289	12,192
Interest income	(600)	(420)	(1,464)
Other income	(1,805)	(1,942)	(776)
Other expense	-	-	671
Loss on early extinguishment of debt	1,972	607	1,820
Total other expenses	29,942	7,534	12,443
Net income before income taxes	234,023	303,466	152,711
Provision (benefit) for income taxes:			
Current	15,022	(20,386)	5,808
Deferred	69,575	129,520	50,474
Total income taxes	84,597	109,134	56,282
Net income	$149,426	$194,332	$96,429
Basic earnings per share	$3.03	$3.97	$1.99
Diluted earnings per share	$3.03	$3.97	$1.99
Average shares outstanding	48,319	47,988	47,681
Average shares outstanding assuming dilution	48,361	48,030	47,706

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,		
	2012	**2011**	**2010**
Net income	$149,426	$194,332	$96,429
Other comprehensive income net of tax effect:			
Adjustment for fair value accounting of derivatives	6,965	36,072	1,176
Comprehensive income	$156,391	$230,404	$97,605

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,		
	2012	**2011**	**2010**
Cash flows from operating activities:			
Net income	$149,426	$194,332	$96,429
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	344,365	280,020	248,201
Accretion expense	33,331	30,764	34,469
Deferred income tax provision	69,575	129,520	50,474
Settlement of asset retirement obligations	(65,567)	(63,391)	(36,901)
Non-cash stock compensation expense	8,699	5,905	5,692
Excess tax benefits	(949)	(1,493)	(299)
Non-cash derivative income	(509)	(2,216)	(324)
Loss on early extinguishment of debt	1,972	607	1,820
Non-cash interest expense	13,085	1,908	858
Other non-cash (income) expense	-	(1,602)	979
Change in current income taxes	10,618	(19,451)	(10,871)
(Increase) decrease in accounts receivable	(55,871)	(19,600)	49,633
(Increase) decrease in other current assets	(2,836)	(66)	74
Decrease in inventory	436	1,619	2,123
Increase (decrease) in accounts payable	5,101	6,039	(773)
Increase (decrease) in other current liabilities	(10,426)	29,583	(18,088)
Other	9,299	(1,628)	1,298
Net cash provided by operating activities	509,749	570,850	424,794
Cash flows from investing activities:			
Investment in oil and gas properties	(555,855)	(764,933)	(401,767)
Proceeds from sale of oil and gas properties, net of expenses	403	87,930	31,635
Sale of fixed assets	134	-	-
Investment in fixed and other assets	(13,370)	(2,247)	(2,949)
Acquisition of non-controlling interest in subsidiary	-	-	(1,007)
Net cash used in investing activities	(568,688)	(679,250)	(374,088)
Cash flows from financing activities:			
Proceeds from bank borrowings	25,000	75,000	-
Repayments of bank borrowings	(70,000)	(30,000)	(175,000)
Proceeds from issuance of senior convertible notes	300,000	-	-
Deferred financing costs of senior convertible notes	(8,855)	-	-
Proceeds from sold warrants	40,170	-	-
Payments for purchased call options	(70,830)	-	-
Proceeds from issuance of senior notes	300,000	-	375,000
Deferred financing costs	(11,966)	(4,017)	(11,474)
Redemption of senior subordinated notes	(200,681)	-	(200,503)
Excess tax benefits	949	1,493	299
Net payments for share based compensation	(3,773)	(2,581)	(1,365)
Net cash provided by (used in) financing activities	300,014	39,895	(13,043)
Net change in cash and cash equivalents	241,075	(68,505)	37,663
Cash and cash equivalents, beginning of year	38,451	106,956	69,293
Cash and cash equivalents, end of year	$279,526	$38,451	$106,956
Supplemental cash flow information:			
Cash (paid) refunded during the year for:			
Interest, net of amount capitalized	($20,150)	($9,808)	($8,760)
Income taxes	(4,405)	935	(26,525)

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)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity
Balance, December 31, 2009	$475	($860)	$1,324,410	($982,986)	($15,380)	$325,659
Net income	-	-	-	96,429	-	96,429
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	1,176	1,176
Exercise of stock options and vesting of restricted stock	3	-	(1,370)	-	-	(1,367)
Amortization of stock compensation expense	-	-	8,462	-	-	8,462
Net tax deficit from stock option exercises and restricted stock vesting	-	-	(2)	-	-	(2)
Balance, December 31, 2010	478	(860)	1,331,500	(886,557)	(14,204)	430,357
Net income	-	-	-	194,332	-	194,332
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	36,072	36,072
Exercise of stock options and vesting of restricted stock	3	-	(2,584)	-	-	(2,581)
Amortization of stock compensation expense	-	-	8,914	-	-	8,914
Net tax benefit from stock option exercises and restricted stock vesting	-	-	735	-	-	735
Balance, December 31, 2011	481	(860)	1,338,565	(692,225)	21,868	667,829
Net income	-	-	-	149,426	-	149,426
Adjustment for fair value accounting of derivatives, net of tax	-	-	-	-	6,965	6,965
Exercise of stock options and vesting of restricted stock	3	-	(3,776)	-	-	(3,773)
Amortization of stock compensation expense	-	-	12,792	-	-	12,792
Net tax benefit from stock option exercises and restricted stock vesting	-	-	814	-	-	814
Convertible notes offering	-	-	38,080	-	-	38,080
Balance, December 31, 2012	$484	($860)	$1,386,475	($542,799)	$28,833	$872,133

The accompanying notes are an integral part of this statement.

NOTE 1 — ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Stone Energy Corporation ("Stone") is an independent oil and natural gas company engaged in the acquisition, exploration, exploitation, development and operation of oil and gas properties. 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. We have expanded our reserve base outside of the conventional shelf of the Gulf of Mexico ("GOM") and into the more prolific reserve basins of the GOM deep water and Gulf Coast deep gas, as well as onshore oil and gas shale opportunities, including the Marcellus Shale in Appalachia. We were incorporated in 1993 as a Delaware corporation. Our corporate headquarters are located at 625 E. Kaliste Saloom Road, Lafayette, Louisiana 70508. We have additional offices in New Orleans, Louisiana, 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"). On September 6, 2012, Caillou Boca was merged into Stone Offshore. On December 31, 2010, Stone Energy, L.L.C. was merged into Stone Offshore. 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 U.S. Generally Accepted Accounting Principles ("GAAP") 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 ("DD&A") expense, unevaluated property costs, estimated future net cash flows from proved reserves, cost to abandon oil and gas properties, taxes, accruals of capitalized costs, operating costs and production revenue, capitalized general and administrative costs and interest, insurance recoveries, effectiveness and estimated fair value of derivative positions, the purchase price allocation on properties acquired, estimates of fair value in business combinations and contingencies.

Fair Value Measurements:

U.S. GAAP establishes a framework for measuring fair value and requires certain disclosures about fair value measurements. As of December 31, 2012 and 2011, 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 marketable securities. Additionally, fair value concepts were applied in recording the acquisition of various deep water assets in December 2011 and June 2012 and the acquisition of an office building in December 2012.

Hybrid Debt Instruments:

In 2012, we issued $300,000 in aggregate principal amount of 1¾% Senior Convertible Notes due 2017 (the "2017 Convertible Notes"). See **Note 11 – Long-Term Debt**. On that same day we entered into convertible note hedging transactions which are expected to reduce the potential dilution to our common stock upon conversion of the notes. In accordance with Accounting Standards Codification ("ASC") 480-20 and ASC 470, we accounted for the debt and equity portions of the notes in a manner that will reflect our nonconvertible borrowing rate when interest is recognized in subsequent periods. This results in the separation of the debt component, classification of the remaining component in equity, and accretion of the resulting discount as part of interest expense. Additionally, the hedging transactions meet the criteria for classification as equity transactions and were recorded as such.

ASC 260 provides that for contracts that may be settled in common stock or in cash at the election of the entity or the holder, the determination of whether the contract shall be reflected in the computation of diluted earnings per share should be made based on the facts available each period. It is presumed that the contract will be settled in common stock and therefore potential dilution be determined using the if-converted method. However, this presumption may be overcome if past experience or a stated policy provides a reasonable basis to believe that the contract will be settled partially or wholly in cash. Because it is management's stated intent to redeem the principal amount of the notes in cash, we have used the treasury stock method for determining potential dilution of the notes in our diluted earnings per share computation in accordance with ASC 260.

Business Combinations:

Our acquisitions in 2012 and 2011 of various deep water assets were accounted for according to the guidance provided in ASC 805, Business Combinations, which requires application of the acquisition method. This methodology requires the recordation of net assets acquired and consideration transferred at fair value. Differences between the net fair value of assets acquired and consideration transferred are recorded as goodwill or a bargain purchase gain.

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 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 DD&A expense. 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 the full cost method, DD&A expense is computed on cost centers represented by entire countries while under the successful efforts method 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 expense using the units of production ("UOP") method. Under the UOP method, the quarterly provision for DD&A expense 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, 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.

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.

Other Property and Equipment:

Our office buildings in Lafayette, Louisiana are being depreciated on the straight-line method over their 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.

Earnings Per Common Share:

Under U.S. GAAP, certain 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.

Production Revenue:

We recognize production revenue under the entitlement method of accounting. Under this method, revenue is deferred for deliveries in excess of our net revenue interest, while revenue is accrued for 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, although for 2011 and 2012, special provisions allowed for current deductions for the cost of certain equipment. 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 expense, and different reporting methods for employee 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 that qualify for cash flow hedge accounting treatment with contemporaneous documentation 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 operating activities. 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 typically determined based on the average of our high and low stock prices on the grant date.

NOTE 2 — EARNINGS PER SHARE:

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

	Year Ended December 31,		
	2012	**2011**	**2010**
Income (numerator):			
Basic:			
Net income	$149,426	$194,332	$96,429
Net income attributable to participating securities	(2,984)	(3,670)	(1,559)
Net income attributable to common stock – basic	$146,442	$190,662	$94,870
Diluted:			
Net income	$149,426	$194,332	$96,429
Net income attributable to participating securities	(2,982)	(3,667)	(1,558)
Net income attributable to common stock – diluted	$146,444	$190,665	$94,871
Weighted average shares (denominator):			
Weighted average shares – basic	48,319	47,988	47,681
Diluted effect of stock options	42	42	25
Weighted average shares - diluted	48,361	48,030	47,706
Basic income per common share	$3.03	$3.97	$1.99
Diluted income per common share	$3.03	$3.97	$1.99

Stock options that were considered antidilutive because the exercise price of the options exceeded the average price of our common stock for the applicable period totaled approximately 347,000, 374,000 and 420,000 shares during the years ended December 31, 2012, 2011 and 2010, respectively.

During the years ended December 31, 2012, 2011 and 2010, approximately 316,000, 312,000 and 255,000 shares of common stock, respectively, were issued from authorized shares upon the vesting (lapse of forfeiture restrictions) of restricted stock by employees and nonemployee directors.

Because it is management's stated intention to redeem the principal amount of our 2017 Convertible Notes (see **Note 11 – Long-Term Debt**) in cash, we have used the treasury method for determining potential dilution in the diluted earnings per share computation. Since the average price of our common stock was less than the effective conversion price for such notes during the reporting period, the 2017 Convertible Notes were not dilutive for such period. Additionally, since the average price of our common stock was less than the strike price of the Sold Warrants (as defined in **Note 11 – Long-Term Debt**) for the reporting period, such warrants were also not dilutive for such period.

NOTE 3 — 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,	
	2012	2011
Other co-venturers	$16,735	$8,890
Trade	130,448	91,959
Insurance receivable	-	4,236
Unbilled accounts receivable	20,053	13,009
Other	52	45
	$167,288	$118,139

We have accrued insurance receivables to the extent we have concluded the insurance recovery is probable. The accrual only relates to costs previously recorded in our financial statements, including asset retirement obligations and repair expenses included in lease operating expenses.

NOTE 4 — CONCENTRATIONS:

Sales to Major Customers

Our production is sold on month-to-month contracts at prevailing prices. We 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,		
	2012	2011	2010
Conoco, Inc.	13%	28%	26%
Hess Corporation	(a)	(a)	11%
Phillips 66 Company	18%	(a)	(a)
Sequent Energy Management LP	(a)	(a)	10%
Shell Trading (US) Company	41%	46%	40%

(a) Less than 10 percent.

The maximum amount of credit risk exposure at December 31, 2012 relating to these customers amounted to $83,432.

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

Approximately18% of our estimated proved reserves (unaudited) at December 31, 2012 and 56% of our production during 2012 were associated with our Gulf Coast Basin conventional shelf properties. Approximately 38% of our estimated proved reserves (unaudited) at December 31, 2012 and 27% of our production during 2012 were associated with our GOM deep water and deep shelf gas properties.

Cash and Cash Equivalents

A substantial portion of our cash balances are not federally insured.

NOTE 5 — ACQUISITIONS AND DIVESTITURES:

Acquisitions

In December 2012, we closed on the acquisition of an office building. The acquisition was accounted for according to the guidance provided in ASC 805, Business Combinations, which requires application of the acquisition method. This methodology requires the recordation of net assets acquired and consideration transferred at fair value. See **Note 8 – Fair Value Measurements**. Differences between the net fair value of assets acquired and consideration transferred are recorded as goodwill or a bargain purchase gain. The building and land were recorded at fair value of $8,539. Consideration transferred in the transaction was $8,539 in cash, resulting in no goodwill or bargain purchase gain.

On June 18, 2012, we completed the acquisition of a 25% working interest in the five block deep water Pompano field in Mississippi Canyon, an approximate 14% working interest in Mississippi Canyon Block 29 and a 10% working interest in certain aliquots of Mississippi Canyon Block 72. The acquisition was also accounted for according to the guidance provided in ASC 805, Business Combinations. Consideration transferred in the transaction was $26,398 in cash, resulting in no goodwill or bargain purchase gain. The following represents the allocation of the recorded value of net assets acquired in the transaction.

Proved oil and gas properties	$39,221
Unevaluated oil and gas properties	1,637
Asset retirement obligations	(14,460)
Total fair value of net assets	$26,398

On December 28, 2011, we completed the acquisition of BP Exploration & Production Inc.'s ("BP") 75% operated working interest in the five block deep water Pompano field in Mississippi Canyon, a 51% operated working interest in the adjacent Mississippi Canyon Block 29, a 50% non-operated working interest in the Mica field, which ties back to the Pompano platform and a 75% interest in 23 deep water exploration leases located in the vicinity of the Pompano field. The acquisition was also accounted for according to the guidance provided in ASC 805, Business Combinations. Consideration transferred in the transaction was $167,631 in cash, resulting in no goodwill or bargain purchase gain. The following represents the allocation of the recorded value of net assets acquired in the transaction.

Proved oil and gas properties	$208,680
Unevaluated oil and gas properties	17,314
Asset retirement obligations	(58,363)
Total fair value of net assets	$167,631

The following unaudited summary pro forma combined statement of operations data of Stone for the year ended December 31, 2011 has been prepared to give effect to the acquisition of the deep water assets from BP as if it had occurred on January 1, 2010. The pro forma financial information is not necessarily indicative of the results that might have occurred had the transaction taken place on January 1, 2010 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, 2011
	(Unaudited)
Revenues	$1,007,376
Income from operations	392,054
Net income	242,118
Basic earnings per share	$4.95
Diluted earnings per share	$4.95

In January 2011, we completed the acquisition of an additional 15% working interest in the Pyrenees project at a cost of approximately $14,974, bringing our ownership up to a 30% working interest. In December 2011, we completed the acquisition of a 25% non-operated working interest in the deep water Wideberth development project at a cost of approximately $31,000 and the assumption of approximately $1,078 of asset retirement obligations. During the second half of 2011, we added approximately 10,000 net acres to our West Virginia leasehold position, including the acquisition of over 6,700 net acres from a single entity at a cost of approximately $19,000.

Divestitures

In the fourth quarter of 2011, we completed the sale of our non-operated interest in the Main Pass Block 296 and 311 fields to two separate parties for total cash consideration of approximately $80,381 and the assumption by the third parties of the associated asset retirement obligation of approximately $10,900. The sale was accounted for as an adjustment to the full cost pool with no gain or loss recognized.

NOTE 6 — 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 in the continental United States:

	Year Ended December 31,		
	2012	2011	2010
Oil and gas properties, proved and unevaluated:			
Balance, beginning of year	$7,049,777	$6,202,758	$5,741,081
Costs incurred during the year (capitalized):			
Acquisition costs, net of sales of unevaluated properties	102,807	270,354	127,069
Exploratory costs	81,458	84,199	42,205
Development costs (1)	395,555	426,355	241,387
Salaries, general and administrative costs	25,318	24,430	20,521
Interest	37,656	42,033	30,783
Less: overhead reimbursements	(310)	(352)	(288)
Total costs incurred during the year, net of divestitures	642,484	847,019	461,677
Balance, end of year	$7,692,261	$7,049,777	$6,202,758
Accumulated depreciation, depletion and amortization (DD&A):			
Balance, beginning of year	($5,174,729)	($4,804,949)	($4,555,372)
Provision for DD&A	(341,096)	(276,480)	(242,745)
Sale of proved properties	5,659	(93,300)	(6,832)
Balance, end of year	($5,510,166)	($5,174,729)	($4,804,949)
Net capitalized costs, proved and unevaluated	$2,182,095	$1,875,048	$1,397,809
DD&A per Mcfe	$3.69	$3.45	$3.08

(1) Includes capitalized asset retirement costs of $95,293, $96,386 and $56,444, respectively.

	2012	2011	2010
Costs incurred during the year (expensed):			
Lease operating expenses	$215,003	$175,881	$150,212
Transportation, processing and gathering expenses	21,782	8,958	7,218
Production taxes	10,015	9,380	5,808
Accretion expense	33,331	30,764	34,469
Expensed costs	$280,131	$224,983	$197,707

The following table discloses net costs incurred (evaluated) on our unevaluated properties:

	Year Ended December 31,		
Unevaluated oil and gas properties:	2012	2011	2010
Net costs incurred (evaluated) during year:			
Acquisition costs	$9,739	($2,397)	$42,664
Exploration costs	(1,209)	(51,207)	10,491
Capitalized interest	37,656	42,033	30,783
	$46,186	($11,571)	$83,938

The following table discloses financial data associated with unevaluated costs at December 31, 2012:

	Balance as of December 31, 2012	Net Costs Incurred During the Year Ended December 31,			
		2012	2011	2010	2009 and prior
Acquisition costs	$258,580	$43,544	$39,984	$104,154	$70,898
Exploration costs	108,248	81,246	2,335	5,151	19,516
Capitalized interest	80,967	30,989	27,818	13,762	8,398
Total unevaluated costs	$447,795	$155,779	$70,137	$123,067	$98,812

Approximately 124 specifically identified drilling projects are included in unevaluated costs at December 31, 2012 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, 2012, 2011 and 2010 totaled $37,656, $42,033 and $30,783, respectively.

NOTE 7 — 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 2013, 2014 and 2015 oil and natural gas production from the Gulf Coast Basin. Some of our fixed-price oil swap settlements are based on an average of the New York Mercantile Exchange ("NYMEX") closing price for West Texas Intermediate during the entire calendar month, and some are based on the average of the Intercontinental Exchange closing price for Brent crude oil during the entire calendar month. Our fixed-price gas swap settlements are based on the NYMEX price for the last day of a respective contract 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 fixed-price swap contracts are with The Toronto-Dominion Bank, Barclays Bank PLC, BNP Paribas, The Bank of Nova Scotia, Bank of America and Natixis.

All of our derivative instruments at December 31, 2012, 2011 and 2010 were designated as effective cash flow hedges; however, during the years ended December 31, 2012, 2011 and 2010, certain of our derivative contracts were determined to be partially ineffective. The following tables disclose the location and fair value amounts of derivative instruments reported in our balance sheet at December 31, 2012 and December 31, 2011.

Fair Value of Derivative Instruments at December 31, 2012

Description	Asset Derivatives: Balance Sheet Location	Asset Derivatives: Fair Value	Liability Derivatives: Balance Sheet Location	Liability Derivatives: Fair Value
Commodity contracts	Current assets: Fair value of hedging contracts	$39,655	Current liabilities: Fair value of hedging contracts	($149)
	Long-term assets: Fair value of hedging contracts	9,199	Long-term liabilities: Fair value of hedging contracts	(1,530)
		$48,854		($1,679)

Fair Value of Derivative Instruments at December 31, 2011

Description	Asset Derivatives: Balance Sheet Location	Asset Derivatives: Fair Value	Liability Derivatives: Balance Sheet Location	Liability Derivatives: Fair Value
Commodity contracts	Current assets: Fair value of hedging contracts	$25,177	Current liabilities: Fair value of hedging contracts	($11,122)
	Long-term assets: Fair value of hedging contracts	22,543	Long-term liabilities: Fair value of hedging contracts	(815)
		$47,720		($11,937)

The following table discloses the effect of derivative instruments in the statement of operations for the years ended December 31, 2012, 2011 and 2010.

The Effect of Derivative Instruments on the Statement of Operations for the Years Ended December 31, 2012, 2011 and 2010

Derivatives in Cash Flow Hedging Relationships	Amount of Gain Recognized in OCI on Derivative (a)	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) (b): Location	Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) (b)	Gain Recognized in Income on Derivative (Ineffective Portion): Location	Gain Recognized in Income on Derivative (Ineffective Portion)
	2012		**2012**		**2012**
Commodity contracts	$6,965	Operating revenue - oil/gas production	$30,326	Derivative income, net	$3,428
Total	$6,965		$30,326		$3,428
	2011		**2011**		**2011**
Commodity contracts	$36,072	Operating revenue - oil/gas production	($13,274)	Derivative income, net	$1,418
Total	$36,072		($13,274)		$1,418
	2010		**2010**		**2010**
Commodity contracts	$1,176	Operating revenue - oil/gas production	$9,631	Derivative income, net	$3,265
Total	$1,176		$9,631		$3,265

(a) Net of related tax effect of $3,918, $20,290 and $292 for the years ended December 31, 2012, 2011 and 2010, respectively.

(b) For the year ended December 31, 2012, effective hedging contracts increased oil revenue by $8,546 and increased gas revenue by $21,780. For the year ended December 31, 2011, effective hedging contracts decreased oil revenue by $32,706 and increased gas revenue by $19,432. For the year ended December 31, 2010, effective hedging contracts decreased oil revenue by $29,047 and increased gas revenue by $38,678.

At December 31, 2012, we had accumulated other comprehensive income of $28,833 net of tax, which related to the fair value of our swap contracts that were outstanding as of December 31, 2012. We believe that approximately $24,033 of the accumulated other comprehensive income will be reclassified into earnings in the next 12 months.

The following table illustrates our hedging positions for calendar years 2013, 2014 and 2015 as of February 21, 2013:

Fixed-Price Swaps
NYMEX (except where noted)

	Natural Gas		Oil	
	Daily Volume (MMBtus/d)	**Swap Price ($)**	**Daily Volume (Bbls/d)**	**Swap Price ($)**
2013	10,000	4.000	1,000	92.80
2013	10,000	5.270	2,000*	94.05
2013	10,000	5.320	1,000	94.45
2013			1,000	94.60
2013			1,000	97.15
2013			1,000	101.53
2013			1,000	103.00
2013			1,000	103.15
2013			1,000	104.25
2013			1,000	104.47
2013			1,000	104.50
2013			1,000 †	107.30
2014	10,000	4.000	1,000	90.06
2014	10,000	4.040	1,000	93.55
2014	10,000	4.105	1,000	94.00
2014	10,000	4.250	1,000	98.00
2014			1,000	98.30
2014			1,000	99.65
2014			1,000 †	103.30
2015	10,000	4.005	1,000	90.00
2015	10,000	4.220		
2015	10,000	4.255		

† Brent oil contract
* January through June

NOTE 8 – FAIR VALUE MEASUREMENTS:

U.S. GAAP establishes a fair value hierarchy that 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, 2012 and December 31, 2011, 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 marketable securities. 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 our credit risk and the credit risk of our 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. For a more detailed description of our derivative instruments, see **Note 7 - Derivative Instruments and Hedging Activities**. We used the market approach in determining the fair value of our investments in marketable securities, 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 at December 31, 2012:

	Fair Value Measurements at December 31, 2012			
Assets	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Marketable securities	$13,492	$13,492	$ -	$ -
Hedging contracts	48,854	-	48,854	-
Total	$62,346	$13,492	$48,854	$ -

	Fair Value Measurements at December 31, 2012			
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	($1,679)	$ -	($1,679)	$ -
Total	($1,679)	$ -	($1,679)	$ -

The following tables present our assets and liabilities that are measured at fair value on a recurring basis at December 31, 2011:

	Fair Value Measurements at December 31, 2011			
Assets	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Marketable securities	$11,961	$11,961	$ -	$ -
Hedging contracts	47,720	-	47,720	-
Total	$59,681	$11,961	$47,720	$ -

	Fair Value Measurements at December 31, 2011			
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	($11,937)	$ -	($11,937)	$ -
Total	($11,937)	$ -	($11,937)	$ -

The fair value of cash and cash equivalents and our variable-rate bank debt approximated book value at December 31, 2012 and 2011. As of December 31, 2012 and 2011, the fair value of our 8⅝% Senior Notes due 2017 (the "2017 Notes") was approximately $401,250 and $386,250, respectively. As of December 31, 2011, the fair value of our 6¾% Senior Subordinated Notes due 2014 (the "2014 Notes") was approximately $199,000. On December 17, 2012, our 2014 Notes were fully redeemed. As of December 31, 2012, the fair value of the liability component of our 2017 Convertible Notes was approximately $249,601. As of December 31, 2012, the fair value of our 7½% Senior Notes due 2022 (the "2022 Notes") was approximately $314,250. The fair value of our outstanding notes was determined based upon quotes obtained from brokers, which represent Level 2 inputs.

We applied fair value concepts in determining the liability component of our 2017 Convertible Notes (see **Note 11 – Long-Term Debt**) at inception and at December 31, 2012. The fair value of the liability was estimated using an income approach. The significant inputs in these determinations were market interest rates based on quotes obtained from brokers and represent Level 2 inputs.

We applied fair value concepts in the recording of various deep water assets acquired in 2011 and 2012. See **Note 5 – Acquisitions and Divestitures**. The fair value of proved and unevaluated oil and gas properties was estimated using a market approach. Significant inputs were market value comparisons for similar transactions within a one-year period. These inputs were considered Level 3 inputs. Asset retirement obligations were determined in accordance with applicable accounting standards.

We applied fair value concepts in recording the acquisition of an office building in 2012. See **Note 5 – Acquisitions and Divestitures**. The fair value of the building was estimated using an income approach. Significant inputs used in this approach were anticipated future earnings (Level 2) and an expected rate of return (Level 3).

NOTE 9 — ASSET RETIREMENT OBLIGATIONS:

The change in our asset retirement obligations during 2012, 2011 and 2010 is set forth below:

	Year Ended December 31,		
	2012	2011	2010
Asset retirement obligations as of the beginning of the year, including current portion	$425,779	$373,920	$320,599
Liabilities incurred	3,869	7,993	1,528
Liabilities settled	(67,641)	(63,226)	(36,392)
Liabilities assumed	15,263	59,441	-
Divestment of properties	(7,563)	(10,900)	(692)
Accretion expense	33,331	30,764	34,469
Revision of estimates	85,264	27,787	54,408
Asset retirement obligations as of the end of the year, including current portion	$488,302	$425,779	$373,920

NOTE 10 — INCOME TAXES:

An analysis of our deferred taxes follows:

	As of December 31,	
	2012	2011
Tax effect of temporary differences:		
Oil and gas properties – full cost	($465,862)	($381,413)
Asset retirement obligations	175,788	153,281
Stock compensation	5,588	4,962
Hedges	(16,983)	(12,882)
Alternative minimum tax credit carryforward	-	5,358
Other	6,153	8,931
	($295,316)	($221,763)

We estimate that we have approximately $15,022, ($20,386) and $5,808 of current federal income tax expense (benefit) for the years ended December 31, 2012, 2011 and 2010, respectively. We have a $10,027 and $19,946 current income tax receivable at December 31, 2012 and 2011, respectively.

A 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,		
	2012	2011	2010
Income tax expense computed at the statutory federal income tax rate	35.0%	35.0%	35.0%
State taxes	1.0	1.0	1.0
IRC Sec. 162(m) limitation	0.6	0.3	-
Other	(0.5)	(0.3)	0.9
Effective income tax rate	36.1%	36.0%	36.9%

In 2012 and 2010, 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 $3,918, $20,290 and $292 for the years ended December 31, 2012, 2011 and 2010, respectively.

As of December 31, 2012 and 2011, we had unrecognized tax benefits of $385. If recognized, all of our unrecognized tax benefits as of December 31, 2012 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, 2011	$385
Increases (decreases) in unrecognized tax benefits as a result of:	-
Tax positions taken during a prior period	-
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, 2012	$385

Our unrecognized tax benefits pertain to proposed state income tax audit adjustments. We believe that our unrecognized tax benefits may be reduced to zero within the next 12 months upon completion and ultimate settlement of the state exams or litigation.

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 $27, $25 and ($1,157) of interest expense related to uncertain tax positions for the years ended December 31, 2012, 2011 and 2010, 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 2008 through 2011 remain subject to examination by major tax jurisdictions.

NOTE 11 — LONG-TERM DEBT:

Long-term debt consisted of the following:

	As of December 31,	
	2012	**2011**
6¾% Senior Subordinated Notes due 2014	$ -	$200,000
8⅝% Senior Notes due 2017	375,000	375,000
1¾% Senior Convertible Notes due 2017	239,126	-
7½% Senior Notes due 2022	300,000	-
Bank debt	-	45,000
Total long-term debt	$914,126	$620,000

Bank Debt

On April 26, 2011, we entered into an amended and restated revolving credit facility with commitments totaling $700,000 (subject to borrowing base limitations) through a syndicated bank group, replacing our previous facility. Our bank credit facility matures on April 26, 2015. On October 22, 2012, the bank group reaffirmed our existing borrowing base at $400,000. As of December 31, 2012 and February 21, 2013, we had no outstanding borrowings under our bank credit facility and letters of credit totaling $20,954 had been issued pursuant to the facility, leaving $379,046 of availability under the facility.

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. If a reduction in our borrowing base were to fall below any outstanding balances under the bank credit facility plus any outstanding letters of credit, our agreement with the banks allows us one or more 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 30 days after our written election to do so or (3) arrange to pay the deficiency in five equal monthly installments.

Our bank credit facility is guaranteed by our only subsidiary, Stone Offshore. 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 our bank 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 bank 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 consolidated EBITDA to consolidated Net Interest Expense, as defined in the credit agreement, for the preceding four quarterly periods of not less than 3.0 to 1. As of December 31, 2012, our debt to EBITDA Ratio was 1.55 to 1 and our EBITDA to consolidated Net Interest Expense Ratio was approximately 21.56 to 1. In addition, our bank 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. These covenants also restrict our ability to prepay other indebtedness under certain circumstances.

Senior Convertible Notes

On March 6, 2012, we issued in a private offering $300,000 in aggregate principal amount of 1¾% Senior Convertible Notes due 2017 to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"). The 2017 Convertible Notes are fully and unconditionally guaranteed on a senior unsecured basis by Stone Offshore and by certain future restricted subsidiaries of Stone. The net proceeds from the sale of the 2017 Convertible Notes were approximately $291,145, after deducting fees and expenses. The 2017 Convertible Notes rank equally in right of payment with all of our existing and future senior unsecured indebtedness. The 2017 Convertible Notes are effectively subordinated to our secured indebtedness to the extent of the value of the related collateral. The 2017 Convertible Notes bear interest at a rate of 1.75% per year, payable on March 1 and September 1 of each year, beginning on September 1, 2012. The 2017 Convertible Notes mature on March 1, 2017, unless earlier converted or repurchased. We may not redeem the 2017 Convertible Notes at our option prior to the maturity date.

The 2017 Convertible Notes are convertible into cash, shares of our common stock or a combination of cash and shares of our common stock, at our election, based on an initial conversion rate of 23.4449 shares of our common stock per $1 principal amount of 2017 Convertible Notes, which corresponds to an initial conversion price of approximately $42.65 per share of our common stock. On December 31, 2012, our closing share price was $20.52. The conversion rate, and thus the conversion price, may be adjusted under certain circumstances as described in the indenture related to the 2017 Convertible Notes.

The 2017 Convertible Notes may be converted by the holder, in multiples of $1 principal amount, only under the following circumstances:

- prior to December 1, 2016, on any date during any calendar quarter beginning after June 30, 2012 (and only during such calendar quarter) if the closing sale price of our common stock was more than 130% of the then current conversion price for at least 20 trading days in the period of the 30 consecutive trading days ending on the last trading day of the previous calendar quarter;

- prior to December 1, 2016, if we distribute to all or substantially all holders of our common stock rights, options or warrants entitling them to purchase, for a period of 45 calendar days or less from the declaration date for such distribution, shares of our common stock at a price per share less than the average closing sale price of our common stock for the 10 consecutive trading days immediately preceding, but excluding, the declaration date for such distribution;

- prior to December 1, 2016, if we distribute to all or substantially all holders of our common stock cash, other assets, securities or rights to purchase our securities, which distribution has a per share value exceeding 10% of the closing sale price of our common stock on the trading day immediately preceding the declaration date for such distribution, or if we engage in certain corporate transactions described in the indenture related to the 2017 Convertible Notes;

- prior to December 1, 2016, during the five consecutive business-day period following any five consecutive trading-day period in which the trading price per $1 principal amount of 2017 Convertible Notes for each trading day during such five trading-day period was less than 98% of the closing sale price of our common stock for each trading day during such five trading-day period multiplied by the then current conversion rate; or

- on or after December 1, 2016, and prior to the close of business on the second scheduled trading day immediately preceding the maturity date of the 2017 Convertible Notes, which is March 1, 2017, without regard to the foregoing conditions.

Upon conversion, we will be obligated to pay or deliver, as the case may be, cash, shares of our common stock or a combination of cash and shares of our common stock, at our election. If we satisfy our conversion obligation solely in cash or through payment and delivery, as the case may be, of a combination of cash and shares of our common stock, the amount of cash and shares of common stock, if any, due upon conversion will be based on a daily conversion value (as described in the indenture related to the 2017 Convertible Notes) calculated on a proportionate basis for each trading day in a 25 consecutive trading-day conversion period (as described in the indenture related to the 2017 Convertible Notes). Upon any conversion, subject to certain exceptions, holders of the 2017 Convertible Notes will not receive any cash payment representing accrued and unpaid interest. Instead, interest will be deemed to be paid by the cash, shares of our common stock or a combination of cash and shares of our common stock paid or delivered, as the case may be, upon conversion of a 2017 Convertible Note.

If we undergo a fundamental change (as defined in the indenture related to the 2017 Convertible Notes) prior to maturity, holders of the 2017 Convertible Notes will have the right, at their option, to require us to repurchase for cash some or all of their 2017 Convertible Notes at a repurchase price equal to 100% of the principal amount of the 2017 Convertible Notes being repurchased, plus accrued and unpaid interest (including additional interest, if any) to, but excluding, the fundamental change repurchase date.

If holders elect to convert the 2017 Convertible Notes in connection with certain fundamental change transactions described in the indenture related to the 2017 Convertible Notes, we will increase the conversion rate by a number of additional shares determined by reference to the provisions contained in the indenture related to the 2017 Convertible Notes based on the effective date of, and the price paid (or deemed paid) per share of our common stock in, such make-whole fundamental change. If holders of our common stock receive only cash in connection with certain make-whole fundamental changes, the price paid (or deemed paid) per share will be the cash amount paid per share. Otherwise, the price paid (or deemed paid) per share will be equal to the average of the closing sale prices of our common stock on the five trading days prior to, but excluding, the effective date of such make-whole fundamental change.

In connection with the sale of the 2017 Convertible Notes, we entered into convertible note hedge transactions with respect to our common stock (the "Purchased Call Options") with Barclays Capital Inc., acting as agent for Barclays Bank PLC, and Bank of America, N.A. (the "Dealers"). We paid an aggregate amount of approximately $70,830 to the Dealers for the Purchased Call Options. The Purchased Call Options cover, subject to customary antidilution adjustments, approximately 7,033,470 shares of our common stock at a strike price that corresponds to the initial conversion price of the 2017 Convertible Notes, also subject to adjustment, and are exercisable upon conversion of the 2017 Convertible Notes.

We also entered into separate warrant transactions whereby, in reliance upon the exemption from registration provided by Section 4(2) of the Securities Act, we sold to the Dealers warrants to acquire, subject to customary antidilution adjustments, approximately 7,033,470 shares of our common stock (the "Sold Warrants") at a strike price of $55.91 per share of common stock. We received aggregate proceeds of approximately $40,170 from the sale of the Sold Warrants to the Dealers. If, upon expiration of the Sold Warrants, the price per share of our common stock, as measured under the Sold Warrants, is greater than the strike price of the Sold Warrants, we will be required to issue, without further consideration, under each Sold Warrant a number of shares of our common stock with a value equal to the amount of such difference.

The Purchased Call Options and Sold Warrants are separate contracts entered into by Stone and each of the Dealers, are not part of the terms of the 2017 Convertible Notes and will not affect the holders' rights under the 2017 Convertible Notes. The Purchased Call Options are expected generally to reduce the potential dilution upon conversion of the 2017 Convertible Notes in the event that the market value per share of our common stock at the time of exercise is greater than the strike price of the Purchased Call Options. The Sold Warrants could separately have a dilutive effect to the extent that the market value per share of our common stock exceeds the applicable strike price of the Sold Warrants.

The estimated liability and equity components of this offering were recorded in accordance with ASC 470-20. The initial carrying amount of the liability component of $229,170 was determined by measuring the fair value of a similar liability that does not have an associated equity component. An effective market interest rate of 7.51% was used in the fair value determination. The carrying amount of the equity component of $70,830 was determined by deducting the fair value of the liability component from the initial proceeds from the 2017 Convertible Notes. Transaction costs of approximately $8,855 were allocated to the liability and equity components in proportion to the allocation of proceeds and accounted for as debt issuance and equity issuance costs, respectively. The cost of the convertible note hedge of $70,830 and proceeds from the warrant transaction of $40,170 were recorded as adjustments to equity. A summary of the entries to record the proceeds from the 2017 Convertible Notes, the cost of the Purchased Call Options and the proceeds from the Sold Warrants is as follows:

Cash	$260,485
Other assets (deferred financing costs)	6,764
Long-term debt	(229,170)
Additional paid-in capital	(38,079)

As of December 31, 2012, the carrying amount of the liability component of the 2017 Convertible Notes was $239,126. During the year ended December 31, 2012, we recorded $9,956 of interest cost for the amortization of the discount and $951 of interest cost for the amortization of deferred financing costs related to the 2017 Convertible Notes. During the year ended December 31, 2012, we recorded $4,302 of interest cost related to the contractual interest coupon on the 2017 Convertible Notes. At December 31, 2012, $1,750 had been accrued in connection with the March 1, 2013 interest payment.

Senior Notes

On November 8, 2012, we completed the public offering of $300,000 aggregate principal amount of 7½% Senior Notes due 2022, which are fully and unconditionally guaranteed on a senior unsecured basis by Stone Offshore and by certain future restricted subsidiaries of Stone. The net proceeds from the offering after deducting underwriting discounts, commissions, fees and expenses totaled $293,203. The 2022 Notes rank equally in right of payment with all of our existing and future senior debt, and rank senior in right of payment to all of our existing and future subordinated debt. The 2022 Notes mature on November 15, 2022, and interest is payable on the 2022 Notes on each May 15 and November 15, commencing on May 15, 2013. We may redeem some or all of the 2022 Notes at any time on or after November 15, 2017 at the redemption prices specified in the indenture, and we may redeem some or all of the 2022 Notes prior to November 15, 2017 at a make-whole redemption price as specified in the indenture. We also may redeem up to 35% of the 2022 Notes prior to November 15, 2015 with cash proceeds from certain equity offerings at a redemption price of 107.500% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date. If we sell certain assets and do not reinvest the proceeds or repay senior indebtedness, or we experience certain changes of control, each as described in the indenture, we must offer to repurchase the 2022 Notes. The 2022 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 2022 Notes a right to accelerate payment. At December 31, 2012, $3,313 had been accrued in connection with the May 15, 2013 interest payment.

On January 26, 2010, we completed a public offering of $275,000 aggregate principal amount of 8⅝% Senior Notes due 2017, which are fully and unconditionally guaranteed on a senior unsecured basis by Stone Offshore and by certain future restricted subsidiaries of Stone. The net proceeds from the offering after deducting underwriting discounts, commissions, fees and expenses totaled $265,299. On November 17, 2010, we completed a public offering of an additional $100,000 aggregate principal amount of our 2017 Notes. The net proceeds from this offering after deducting underwriting discounts, commissions, fees and expenses totaled approximately $98,227. The 2017 Notes rank equally in right of payment with all of our existing and future senior debt, and rank senior in right of payment to all of our existing and future subordinated debt. The 2017 Notes mature on February 1, 2017, and interest is payable on each February 1 and August 1, commencing on August 1, 2010. We may, at our option, redeem all or part of the 2017 Notes at any time prior to February 1, 2014 at a make-whole redemption price, and at any time on or after February 1, 2014 at fixed redemption prices. In addition, prior to February 1, 2013, we may, at our option, redeem up to 35% of the 2017 Notes with the cash proceeds of certain equity offerings. The 2017 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 2017 Notes a right to accelerate payment. At December 31, 2012, $13,477 had been accrued in connection with the February 1, 2013 interest payment.

Senior Subordinated Notes

On December 15, 2004, we issued \$200,000 6¾% Senior Subordinated Notes due 2014. In November 2012, we used proceeds from the 2022 Notes offering to purchase a portion of our 2014 Notes pursuant to a tender offer and consent solicitation. In December 2012, the remaining 2014 Notes were redeemed in full. The total cost of the redemption was \$204,355, which included \$200,681 to redeem the notes plus accrued and unpaid interest of \$3,674. The transaction resulted in a charge to earnings of \$1,972 in 2012.

On December 5, 2001, we issued \$200,000 8¼% Senior Subordinated Notes due 2011 (the "2011 Notes"). In January 2010, we used the proceeds from the 2017 Notes offering to purchase our 2011 Notes pursuant to a tender offer and consent solicitation. In February 2010, the remaining 2011 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 resulted in a charge to earnings of \$1,820 in 2010.

Deferred Financing Cost and Interest Cost

Other assets at December 31, 2012 and 2011 included approximately \$27,753 and \$14,437, respectively, of deferred financing costs, net of accumulated amortization. These costs at December 31, 2012 related primarily to the issuance of the 2017 Convertible Notes, the 2022 Notes, the 2017 Notes and our bank credit facility. The costs associated with the 2017 Convertible Notes, the 2022 Notes and the 2017 Notes are being amortized over the life of the notes using a method that applies effective interest rates of 7.51%, 7.75% and 8.08%, respectively. The costs associated with our bank credit facility are being amortized over the term of the facility.

Total interest cost incurred, before capitalization, on all obligations for the years ended December 31, 2012, 2011 and 2010 was \$68,031, \$51,322 and \$42,975 respectively.

NOTE 12 — STOCK-BASED COMPENSATION:

We record stock compensation expense under U.S. GAAP for stock options and other equity-based compensation awards based on the fair value on the date of grant. Compensation expense for equity-based compensation awards is recognized in our financial statements over the vesting period of the award.

For the year ended December 31, 2012, we incurred \$13,399 of stock based compensation, of which \$13,308 related to restricted stock issuances, \$91 related to stock option grants and of which a total of approximately \$4,288 was capitalized into oil and gas properties. For the year ended December 31, 2011, we incurred \$8,914 of stock based compensation, of which \$8,796 related to restricted stock issuances, \$118 related to stock option grants and of which a total of approximately \$3,010 was capitalized into oil and gas properties. For the year ended December 31, 2010, we incurred \$8,462 of stock based compensation, of which \$8,263 related to restricted stock issuances, \$199 related to stock option grants and of which a total of approximately \$2,775 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 net income 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 the Stone Energy Corporation 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 10 years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire 10 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 one- to three-year period.

Stock Options. There were no stock option grants during the years ended December 31, 2012, 2011 or 2010.

A summary of stock option activity under the 2009 Plan during the year ended December 31, 2012 is as follows (amounts in table represent actual values except where indicated otherwise):

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Term	Aggregate Intrinsic Value (in thousands)
Options outstanding, beginning of period	438,394	$38.76		
Granted	-	-		
Exercised	-	-		
Forfeited	(4,200)	35.54		
Expired	(22,400)	34.25		
Options outstanding, end of period	411,794	39.04	2.8 years	$766
Options exercisable, end of period	378,004	41.00	2.5 years	459
Options unvested, end of period	33,790	17.17	5.4 years	307

Exercise prices for stock options outstanding at December 31, 2012 range from $6.97 to $53.20.

A summary of stock option activity under the 2009 Plan during the year ended December 31, 2011 is as follows (amounts in table represent actual values except where indicated otherwise):

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Term	Aggregate Intrinsic Value (in thousands)
Options outstanding, beginning of period	484,694	$39.43		
Granted	-	-		
Exercised	-	-		
Forfeited	(13,300)	37.98		
Expired	(33,000)	48.85		
Options outstanding, end of period	438,394	38.76	3.6 years	$1,143
Options exercisable, end of period	378,710	41.66	3.1 years	457
Options unvested, end of period	59,684	20.36	6.1 years	686

A summary of stock option activity under the 2009 Plan during the year ended December 31, 2010 is as follows (amounts in table represent actual values except where indicated otherwise):

	Number of Options	Wgtd. Avg. Exercise Price	Wgtd. Avg. Term	Aggregate Intrinsic Value (in thousands)
Options outstanding, beginning of period	495,283	$39.61		
Granted	-	-		
Exercised	-	-		
Forfeited	(6,190)	40.85		
Expired	(4,399)	57.76		
Options outstanding, end of period	484,694	39.43	3.8 years	$880
Options exercisable, end of period	396,115	43.21	3.4 years	176
Options unvested, end of period	88,579	22.50	6.9 years	704

Restricted Stock. The fair value of restricted shares is typically determined based on the average of our high and low stock prices on the grant date. During the year ended December 31, 2012, we issued 670,818 shares of restricted stock valued at $21,085. During the year ended December 31, 2011, we issued 597,062 shares of restricted stock valued at $14,100. During the year ended December 31, 2010, we issued 395,869 shares of restricted stock valued at $6,251.

A summary of the restricted stock activity under the 2009 Plan for the years ended December 31, 2012, 2011 and 2010 is as follows (amounts in table represent actual values):

	2012		2011		2010	
	Number of Restricted Shares	Wgtd. Avg. Fair Value Per Share	Number of Restricted Shares	Wgtd. Avg. Fair Value Per Share	Number of Restricted Shares	Wgtd. Avg. Fair Value Per Share
Restricted stock outstanding, beginning of period	923,740	$20.08	783,606	$17.24	751,437	$20.68
Issuances	670,818	31.43	597,062	23.62	395,869	15.79
Lapse of restrictions	(462,141)	18.29	(419,543)	19.91	(343,657)	23.09
Forfeitures	(23,543)	26.10	(37,385)	18.92	(20,043)	18.07
Restricted stock outstanding, end of period	1,108,874	$27.56	923,740	$20.08	783,606	$17.24

As of December 31, 2012, there was $18,547 of unrecognized compensation cost related to all non-vested share-based compensation arrangements under the 2009 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 1.8 years.

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 the pool of available excess tax benefits to offset such deficit. Adjustments to additional paid-in capital related to the net tax effect of stock option exercises and restricted stock vesting were $814, $735 and ($2) in 2012, 2011 and 2010, respectively.

NOTE 13 — 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, 2012, 300,000 shares had been repurchased under this program at a total cost of $7,071, or an average price of $23.57 per share. No shares were repurchased during the years ended December 31, 2012, 2011 and 2010.

NOTE 14 — COMMITMENTS AND CONTINGENCIES:

Lease Commitments

We lease office facilities in Lafayette and New Orleans, Louisiana, Houston, Texas and Morgantown, West Virginia under the terms of long-term, non-cancelable leases expiring on various dates through 2018. 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 with non-cancelable terms in excess of 12 months at December 31, 2012 were as follows:

2013	$612
2014	540
2015	540
2016	260
2017	203
2018	82

Payments related to our lease obligations for the years ended December 31, 2012, 2011 and 2010 were approximately $894, $446 and $703, respectively.

Other Commitments

We are contingently liable to surety insurance companies in the amount of $90,789 relative to bonds issued on our behalf to the Bureau of Ocean Energy Management ("BOEM"), 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.

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 $52,299 to be incurred over the next three years.

The Oil Pollution Act ("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 the OPA and a final rule adopted by the BOEM 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 Outer Continental Shelf ("OCS") waters, with higher amounts of up to $150,000 in certain limited circumstances where the BOEM 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 BOEM's final rule. We do not anticipate that we will experience any difficulty in continuing to satisfy the BOEM's requirements for demonstrating financial responsibility under the OPA and the BOEM's regulations.

Litigation

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 that these matters, individually or in the aggregate, will have a material adverse effect on our financial condition.

We have been served with several petitions filed by the Louisiana Department of Revenue ("LDR") in Louisiana state court claiming additional franchise taxes due. In addition, we have received preliminary assessments from the LDR for additional franchise taxes resulting from audits of Stone and other subsidiaries. These assessments all relate to the LDR's assertion that sales of crude oil and natural gas from properties located on the OCS, 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. We disagree with these contentions and are defending ourselves against these claims. Total asserted claims plus estimated accrued interest amount to approximately $29,581. The franchise tax years 2010, 2011 and 2012 for Stone remain subject to examination, which potentially exposes us to additional estimated assessments of $2,440 including accrued interest. We estimate the potential range of loss upon resolution of this matter to be between $0 and $32,021.

NOTE 15 — EMPLOYEE BENEFIT PLANS:

We have entered into deferred compensation and disability agreements with certain of our officers and former officers. The benefits under the deferred compensation agreements vest after certain periods of employment, and at December 31, 2012, the liability for such vested benefits was approximately $1,059 and is recorded in current and other long-term liabilities.

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

Annual Cash Incentive Compensation Plan

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 $8,113, $11,600, and $5,888, net of amounts capitalized, for each of the years ended December 31, 2012, 2011 and 2010, respectively, related to incentive compensation bonuses to be paid under the revised plan.

Stock Incentive Plans

At the 2011 Annual Meeting of Stockholders, the stockholders approved the First Amendment (the "First Amendment") to the 2009 Plan. The First Amendment increases the number of shares of common stock that Stone may issue under the 2009 Plan, and the number of shares of common stock that may be issued under the 2009 Plan through incentive stock options by 2,800,000 shares, effective May 20, 2011. 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 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 10 years subsequent to award. Stock options issued to non-employee directors vest ratably over a three-year service-vesting period and expire 10 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 one to three years at the discretion of the Compensation Committee of the board of directors. At December 31, 2012, we had approximately 2,684,466 additional shares available for issuance pursuant to the Plan.

401(k) and Deferred Compensation Plans

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, 2012, 2011 and 2010, Stone contributed $1,759, $1,435 and $1,301, respectively, to the plan.

The Stone Energy Corporation Deferred Compensation Plan provides eligible executives and employees 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, 2012 and 2011, plan assets of $7,498 and $6,410, respectively, were included in other assets. An equal amount of plan liabilities were included in other long-term liabilities.

Change of Control and Severance Plans

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 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 of 1986, as amended (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 of directors. 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 six-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) weekly pay times 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 pro-rated 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 12.

NOTE 16 — OIL AND GAS RESERVE INFORMATION – UNAUDITED:

Our estimated net proved oil and gas reserves at December 31, 2012 have been prepared in accordance with guidelines established by the Securities and Exchange Commission ("SEC"). Accordingly, the following reserve estimates are based upon existing economic and operating conditions at the respective dates. 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), natural gas and natural gas liquids ("NGL") reserves, all of which are located onshore and offshore the continental United States. Estimated proved oil, natural gas and NGL reserves at December 31, 2012, 2011 and 2010 are prepared in accordance with the SEC's rule, "Modernization of Oil and Gas Reporting," using a 12-month average pricing assumption. In the first quarter of 2012, we began reporting NGL volumes and revenues separately from gas volumes. Historically, we reported "wet" gas volumes, which included entrained liquids. We now report NGLs and "dry" gas (shrunk for removal of liquids) volumes. Reserve volumes for the year ended December 31, 2011 have been reclassified to conform to the current presentation. Reserve volumes for the years ended December 31, 2010 and 2009 have not been reclassified to conform to the current presentation given the immateriality of NGL volumes in such periods.

	Oil (MBbls)	NGLs (MBbls)	Natural Gas (MMcf)	Oil, Natural Gas and NGLs (MMcfe)
Estimated proved reserves as of December 31, 2009	32,336	-	216,694	410,711
Revisions of previous estimates	3,299	574	12,670	35,906
Extensions, discoveries and other additions	2,668	-	82,846	98,854
Purchase of producing properties	637	-	3,816	7,637
Sale of reserves	(23)	-	(153)	(289)
Production	(5,714)	(574)	(41,168)	(78,896)
Estimated proved reserves as of December 31, 2010	33,203	-	274,705	473,923
Revisions of previous estimates	2,889	4,911	(26,725)	20,075
Extensions, discoveries and other additions	3,544	-	93,520	114,784
Purchase of producing properties	14,396	-	24,595	110,971
Sale of reserves	(1,950)	-	(2,150)	(13,850)
Production	(6,427)	(506)	(38,466)	(80,064)
Estimated proved reserves as of December 31, 2011	45,655	4,405	325,479	625,839
Revisions of previous estimates	(1,559)	9,349	(26,694)	20,050
Extensions, discoveries and other additions	3,681	4,856	131,408	182,633
Purchase of producing properties	4,336	619	8,168	37,895
Sale of reserves	(60)	-	(418)	(775)
Production	(7,135)	(1,163)	(42,569)	(92,357)
Estimated proved reserves as of December 31, 2012	44,918	18,066	395,374	773,285
Estimated proved developed reserves:				
as of December 31, 2010	25,000	-	174,876	324,876
as of December 31, 2011	30,914	3,195	171,871	376,528
as of December 31, 2012	29,005	8,593	210,956	436,540

The following narrative provides the reasons for the significant changes in the quantities of our estimated proved reserves by year.

Year Ended December 31, 2012. Extensions, discoveries and other additions were primarily the result of our Appalachia drilling program (162 Bcfe) and our deep gas development project at LaCantera (17 Bcfe). Purchase of producing properties relates to our acquisition of an additional interest in the Pompano field.

Year Ended December 31, 2011. Extensions, discoveries and other additions were primarily the result of our Appalachia drilling program (94 Bcfe), our deep gas development project at LaPosada (11 Bcfe) and our GOM drilling program at Mississippi Canyon Block 109 (6 Bcfe). Purchase of producing properties primarily relates to our acquisition of the Pompano and Mica fields (102 Bcfe) and our acquisition of an additional 15% working interest in the Pyrenees project (6 Bcfe). Sale of reserves primarily relates to the sale of our non-operated interest in the Main Pass Block 296 and 311 fields (13 Bcfe).

Year Ended December 31, 2010. Revisions of previous estimates were the result of positive reserve report pricing changes extending the economic limits of reservoirs (28 Bcfe) and well performance (5 Bcfe). Extensions, discoveries and other additions were primarily the result of our Appalachia drilling program (77 Bcfe) and our GOM drilling program primarily at Mississippi Canyon Block 109 (18 Bcfe).

The following tables present the standardized measure of discounted future net cash flows related to estimated proved oil, natural gas and NGL 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, 2012. 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, natural gas and NGL reserves. Prices are 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 2012 average 12-month oil and gas prices net of differentials were $101.20 per Bbl of oil, $38.23 per Bbl of NGLs and $2.68 per Mcf of gas. The 2011 average 12-month oil and gas prices net of differentials were $100.97 per Bbl of oil, $58.26 per Bbl of NGLs and $4.74 per Mcf of gas. The 2010 average 12-month oil and gas prices net of differentials were $77.68 per Bbl of oil and $4.46 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,		
	2012	**2011**	**2010**
Future cash inflows	$6,295,455	$6,171,279	$3,803,004
Future production costs	(1,946,426)	(1,747,806)	(1,191,718)
Future development costs	(1,241,531)	(1,219,214)	(907,956)
Future income taxes	(799,007)	(852,364)	(330,651)
Future net cash flows	2,308,491	2,351,895	1,372,679
10% annual discount	(794,632)	(808,933)	(415,050)
Standardized measure of discounted future net cash flows	$1,513,859	$1,542,962	$957,629

	Changes in Standardized Measure Year Ended December 31,		
	2012	2011	2010
Standardized measure at beginning of year	$1,542,962	$957,629	$614,987
Sales and transfers of oil, gas and NGLs produced, net of production costs	(697,741)	(670,347)	(487,418)
Changes in price, net of future production costs	(380,841)	502,324	485,272
Extensions and discoveries, net of future production and development costs	178,272	293,168	270,629
Changes in estimated future development costs, net of development costs incurred during the period	212,329	97,852	119,986
Revisions of quantity estimates	76,450	(27,854)	147,509
Accretion of discount	207,292	118,722	64,836
Net change in income taxes	22,947	(300,363)	(196,219)
Purchases of reserves in-place	276,389	567,286	21,264
Sales of reserves in-place	2,480	(36,278)	1,424
Changes in production rates due to timing and other	73,320	40,823	(84,641)
Net increase (decrease) in standardized measure	(29,103)	585,333	342,642
Standardized measure at end of year	$1,513,859	$1,542,962	$957,629

NOTE 17 — SUMMARIZED QUARTERLY FINANCIAL INFORMATION – UNAUDITED:

The results of operations by quarter are as follows:

	2012 Quarter Ended			
	March 31	June 30	September 30	December 31
Operating revenue	$244,957	$226,561	$227,397	$254,871
Income from operations	84,927	56,156	44,485	78,397
Net income	50,974	30,547	23,659	44,246
Basic earnings per share	$1.03	$0.62	$0.48	$0.89
Diluted earnings per share	$1.03	$0.62	$0.48	$0.89

	2011 Quarter Ended			
	March 31	June 30	September 30	December 31
Operating revenue	$200,039	$235,734	$214,594	$223,616
Income from operations	64,752	92,155	80,694	73,399
Net income	39,792	57,196	51,821	45,523
Basic earnings per share	$0.81	$1.17	$1.06	$0.93
Diluted earnings per share	$0.81	$1.17	$1.06	$0.93

NOTE 18 – GUARANTOR FINANCIAL STATEMENTS:

Stone Offshore is an unconditional guarantor (the "Guarantor Subsidiary") of our 2017 Notes, 2017 Convertible Notes and 2022 Notes. Our other subsidiary (the "Non-Guarantor Subsidiary") did not provide a guarantee. Our non-guarantor subsidiary, Caillou Boca, was merged into Stone Offshore on September 6, 2012. The following presents consolidating financial information as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010 on an issuer (parent company), guarantor subsidiary, non-guarantor subsidiary, and consolidated basis. Elimination entries presented are necessary to combine the entities.

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2012
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$228,398	$51,128	$ -	$ -	$279,526
Accounts receivable	59,213	108,075	-	-	167,288
Fair value of hedging contracts	-	39,655	-	-	39,655
Current income tax receivable	10,027	-	-	-	10,027
Deferred taxes *	5,947	9,567	-	-	15,514
Inventory	3,924	283	-	-	4,207
Other current assets	3,626	-	-	-	3,626
Total current assets	311,135	208,708	-	-	519,843
Oil and gas properties, full cost method:					
Proved, net	634,697	1,099,603	-	-	1,734,300
Unevaluated	254,757	193,038	-	-	447,795
Other property and equipment, net	22,115	-	-	-	22,115
Fair value of hedging contracts	-	9,199	-	-	9,199
Other assets, net	41,679	1,500	-	-	43,179
Investment in subsidiary	736,331	-	-	(736,331)	-
Total assets	$2,000,714	$1,512,048	$ -	($736,331)	$2,776,431
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable to vendors	$74,503	$19,858	$ -	$ -	$94,361
Undistributed oil and gas proceeds	21,841	1,573	-	-	23,414
Accrued interest	18,546	-	-	-	18,546
Fair value of hedging contracts	-	149	-	-	149
Asset retirement obligations	-	66,260	-	-	66,260
Other current liabilities	16,765	-	-	-	16,765
Total current liabilities	131,655	87,840	-	-	219,495
Long-term debt	914,126	-	-	-	914,126
Deferred taxes *	47,758	263,072	-	-	310,830
Asset retirement obligations	5,479	416,563	-	-	422,042
Fair value of hedging contracts	-	1,530	-	-	1,530
Other long-term liabilities	29,563	6,712	-	-	36,275
Total liabilities	1,128,581	775,717	-	-	1,904,298
Commitments and contingencies					
Stockholders' equity:					
Common stock	484	-	-	-	484
Treasury stock	(860)	-	-	-	(860)
Additional paid-in capital	1,386,475	1,496,510	-	(1,496,510)	1,386,475
Accumulated earnings (deficit)	(542,799)	(789,012)	-	789,012	(542,799)
Accumulated other comprehensive income (loss)	28,833	28,833	-	(28,833)	28,833
Total stockholders' equity	872,133	736,331	-	(736,331)	872,133
Total liabilities and stockholders' equity	$2,000,714	$1,512,048	$ -	($736,331)	$2,776,431

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

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2011
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$37,389	$926	$136	$ -	$38,451
Accounts receivable	36,463	81,452	1,353	(1,129)	118,139
Fair value of hedging contracts	-	25,177	-	-	25,177
Current income tax receivable	19,946	-	-	-	19,946
Deferred taxes *	8,269	17,803	-	-	26,072
Inventory	4,360	283	-	-	4,643
Other current assets	791	-	-	-	791
Total current assets	107,218	125,641	1,489	(1,129)	233,219
Oil and gas properties, full cost method:					
Proved, net	387,554	1,083,192	2,693	-	1,473,439
Unevaluated	246,269	155,340	-	-	401,609
Other property and equipment, net	11,172	-	-	-	11,172
Fair value of hedging contracts	-	22,543	-	-	22,543
Other assets, net	20,873	2,896	-	-	23,769
Investment in subsidiary	733,533	(273)	-	(733,260)	-
Total assets	$1,506,619	$1,389,339	$4,182	($734,389)	$2,165,751
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable to vendors	$78,170	$25,866	$39	($1,129)	$102,946
Undistributed oil and gas proceeds	26,036	1,292	-	-	27,328
Accrued interest	14,059	-	-	-	14,059
Fair value of hedging contracts	-	11,122	-	-	11,122
Asset retirement obligations	-	62,676	-	-	62,676
Other current liabilities	22,974	5,396	-	-	28,370
Total current liabilities	141,239	106,352	39	(1,129)	246,501
Long-term debt	620,000	-	-	-	620,000
Deferred taxes *	56,970	190,865	-	-	247,835
Asset retirement obligations	7,626	351,061	4,416	-	363,103
Fair value of hedging contracts	-	815	-	-	815
Other long-term liabilities	12,955	6,713	-	-	19,668
Total liabilities	838,790	655,806	4,455	(1,129)	1,497,922
Commitments and contingencies					
Stockholders' equity:					
Common stock	481	-	-	-	481
Treasury stock	(860)	-	-	-	(860)
Additional paid-in capital	1,338,565	1,724,232	1,639	(1,725,871)	1,338,565
Accumulated earnings (deficit)	(692,225)	(1,012,567)	(1,912)	1,014,479	(692,225)
Accumulated other comprehensive income (loss)	21,868	21,868	-	(21,868)	21,868
Total stockholders' equity	667,829	733,533	(273)	(733,260)	667,829
Total liabilities and stockholders' equity	$1,506,619	$1,389,339	$4,182	($734,389)	$2,165,751

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

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2012
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Operating revenue:					
Oil production	$26,149	$735,155	$ -	$ -	$761,304
Gas production	34,331	100,408	-	-	134,739
Natural gas liquids production	15,264	33,234	-	-	48,498
Other operational income	2,766	397	357	-	3,520
Derivative income, net	-	3,428	-	-	3,428
Total operating revenue	78,510	872,622	357	-	951,489
Operating expenses:					
Lease operating expenses	19,914	195,105	(16)	-	215,003
Transportation, processing, and gathering expenses	12,049	9,733	-	-	21,782
Production taxes	3,330	6,685	-	-	10,015
Depreciation, depletion, amortization	63,022	281,152	191	-	344,365
Accretion expense	561	32,513	257	-	33,331
Salaries, general and administrative	54,641	7	-	-	54,648
Incentive compensation expense	8,113	-	-	-	8,113
Other operational expenses	173	94	-	-	267
Total operating expenses	161,803	525,289	432	-	687,524
Income (loss) from operations	(83,293)	347,333	(75)	-	263,965
Other (income) expenses:					
Interest expense	30,446	(71)	-	-	30,375
Interest income	(285)	(315)	-	-	(600)
Other income	(144)	(1,661)	-	-	(1,805)
Loss on early extinguishment of debt	1,972	-	-	-	1,972
(Income) loss from investment in subsidiaries	(223,555)	75	-	223,480	-
Total other (income) expenses	(191,566)	(1,972)	-	223,480	29,942
Income (loss) before taxes	108,273	349,305	(75)	(223,480)	234,023
Provision (benefit) for income taxes:					
Current	15,022	-	-	-	15,022
Deferred	(56,175)	125,750	-	-	69,575
Total income taxes	(41,153)	125,750	-	-	84,597
Net income (loss)	$149,426	$223,555	($75)	($223,480)	$149,426
Comprehensive income (loss)	$156,391	$223,555	($75)	($223,480)	$156,391

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2011
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Operating revenue:					
Oil production	$5,675	$658,283	$ -	$ -	$663,958
Gas production	19,470	151,141	-	-	170,611
Natural gas liquids production	-	29,996	-	-	29,996
Other operational income	3,085	249	604	-	3,938
Derivative income, net	-	1,418	-	-	1,418
Total operating revenue	28,230	841,087	604	-	869,921
Operating expenses:					
Lease operating expenses	6,632	169,018	231	-	175,881
Transportation, processing and gathering expenses	-	8,958	-	-	8,958
Production taxes	1,434	7,946	-	-	9,380
Depreciation, depletion, amortization	17,860	261,326	834	-	280,020
Accretion expense	15	30,385	364	-	30,764
Salaries, general and administrative	40,073	94	2	-	40,169
Incentive compensation expense	11,600	-	-	-	11,600
Other operational expenses	1,404	745	-	-	2,149
Total operating expenses	79,018	478,472	1,431	-	558,921
Income (loss) from operations	(50,788)	362,615	(827)	-	311,000
Other (income) expenses:					
Interest expense	9,043	246	-	-	9,289
Interest income	(178)	(242)	-	-	(420)
Other (income) expense, net	(52)	(1,890)	-	-	(1,942)
Loss on early extinguishment of debt	607	-	-	-	607
(Income) loss from investment in subsidiaries	(232,751)	827	-	231,924	-
Total other (income) expenses	(223,331)	(1,059)	-	231,924	7,534
Income (loss) before taxes	172,543	363,674	(827)	(231,924)	303,466
Provision (benefit) for income taxes:					
Current	(20,386)	-	-	-	(20,386)
Deferred	(1,403)	130,923	-	-	129,520
Total income taxes	(21,789)	130,923	-	-	109,134
Net income (loss)	$194,332	$232,751	($827)	($231,924)	$194,332
Comprehensive income (loss)	$230,404	$232,751	($827)	($231,924)	$230,404

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
YEAR ENDED DECEMBER 31, 2010
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Operating revenue:					
Oil production	$51,357	$366,591	$ -	$ -	$417,948
Gas production	61,137	149,549	-	-	210,686
Natural gas liquids production	-	27,473	-	-	27,473
Other operational income	4,831	(54)	1,139	-	5,916
Derivative income, net	3,265	-	-	-	3,265
Total operating revenue	120,590	543,559	1,139	-	665,288
Operating expenses:					
Lease operating expenses	64,868	85,344	-	-	150,212
Transportation, processing and gathering expenses	-	7,218	-	-	7,218
Production taxes	3,631	2,177	-	-	5,808
Depreciation, depletion, amortization	40,351	206,856	994	-	248,201
Accretion expense	14,503	19,524	442	-	34,469
Salaries, general and administrative	42,741	17	1	-	42,759
Incentive compensation expense	5,888	-	-	-	5,888
Other operational expenses	2,097	3,482	-	-	5,579
Total operating expenses	174,079	324,618	1,437	-	500,134
Income (loss) from operations	(53,489)	218,941	(298)	-	165,154
Other (income) expenses:					
Interest expense	12,192	-	-	-	12,192
Interest income	(1,439)	(25)	-	-	(1,464)
Other income	(53)	(762)	39	-	(776)
Other expense	601	70	-	-	671
Loss on early extinguishment of debt	1,820	-	-	-	1,820
(Income) loss from investment in subsidiary	(140,366)	337	-	140,029	-
Total other (income) expenses	(127,245)	(380)	39	140,029	12,443
Income (loss) before taxes	73,756	219,321	(337)	(140,029)	152,711
Provision (benefit) for income taxes:					
Current	5,896	(88)	-	-	5,808
Deferred	(28,569)	79,043	-	-	50,474
Total income taxes	(22,673)	78,955	-	-	56,282
Net income (loss)	$96,429	$140,366	($337)	($140,029)	$96,429
Comprehensive income (loss)	$97,605	$140,366	($337)	($140,029)	$97,605

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2012
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$149,426	$223,555	($75)	($223,480)	$149,426
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion and amortization	63,022	281,152	191	-	344,365
Accretion expense	561	32,513	257	-	33,331
Deferred income tax provision (benefit)	(56,175)	125,750	-	-	69,575
Settlement of asset retirement obligations	-	(65,567)	-	-	(65,567)
Non-cash stock compensation expense	8,699	-	-	-	8,699
Excess tax benefits	(949)	-	-	-	(949)
Non-cash derivative income	-	(509)	-	-	(509)
Loss on early extinguishment of debt	1,972	-	-	-	1,972
Non-cash interest expense	13,085	-	-	-	13,085
Non-cash (income) loss from investment in subsidiaries	(223,555)	75	-	223,480	-
Change in current income taxes	10,618	-	-	-	10,618
Change in intercompany receivables/payables	275,819	(275,125)	(694)	-	-
(Increase) decrease in accounts receivable	(22,750)	(33,345)	224	-	(55,871)
Increase in other current assets	(2,836)	-	-	-	(2,836)
Decrease in inventory	436	-	-	-	436
Increase (decrease) in accounts payable	5,348	(208)	(39)	-	5,101
Decrease in other current liabilities	(5,311)	(5,115)	-	-	(10,426)
Other	10,960	(1,661)	-	-	9,299
Net cash provided by (used in) operating activities	228,370	281,515	(136)	-	509,749
Cash flows from investing activities:					
Investment in oil and gas properties	(324,542)	(231,313)	-	-	(555,855)
Proceeds from sale of oil and gas properties, net of expenses	403	-	-	-	403
Sale of fixed assets	134	-	-	-	134
Investment in fixed and other assets	(13,370)	-	-	-	(13,370)
Net cash used in investing activities	(337,375)	(231,313)	-	-	(568,688)
Cash flows from financing activities:					
Proceeds from bank borrowings	25,000	-	-	-	25,000
Repayment of bank borrowings	(70,000)	-	-	-	(70,000)
Proceeds from issuance of senior convertible notes	300,000	-	-	-	300,000
Deferred financing costs of senior convertible notes	(8,855)	-	-	-	(8,855)
Proceeds from sold warrants	40,170	-	-	-	40,170
Payments for purchased call options	(70,830)	-	-	-	(70,830)
Proceeds from issuance of senior notes	300,000	-	-	-	300,000
Deferred financing costs	(11,966)	-	-	-	(11,966)
Redemption of senior subordinated notes	(200,681)	-	-	-	(200,681)
Excess tax benefits	949	-	-	-	949
Net payments for share based compensation	(3,773)	-	-	-	(3,773)
Net cash provided by financing activities	300,014	-	-	-	300,014
Net change in cash and cash equivalents	191,009	50,202	(136)	-	241,075
Cash and cash equivalents, beginning of period	37,389	926	136	-	38,451
Cash and cash equivalents, end of period	$228,398	$51,128	$ -	$ -	$279,526

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2011
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$194,332	$232,751	($827)	($231,924)	$194,332
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion and amortization	17,860	261,326	834	-	280,020
Accretion expense	15	30,385	364	-	30,764
Deferred income tax provision (benefit)	(1,403)	130,923	-	-	129,520
Settlement of asset retirement obligations	-	(63,391)	-	-	(63,391)
Non-cash stock compensation expense	5,905	-	-	-	5,905
Excess tax benefits	(1,493)	-	-	-	(1,493)
Non-cash derivative income	-	(2,216)	-	-	(2,216)
Loss on early extinguishment of debt	607	-	-	-	607
Non-cash interest expense	1,908	-	-	-	1,908
Other non-cash income	(1,602)	-	-	-	(1,602)
Non-cash (income) loss from investment in subsidiaries	(230,861)	(1,063)	-	231,924	-
Change in current income taxes	(19,451)	-	-	-	(19,451)
Change in intercompany receivables/payables	217,287	(217,724)	437	-	-
Increase in accounts receivable	(11,022)	(7,688)	(890)	-	(19,600)
(Increase) decrease in other current assets	(80)	14	-	-	(66)
Decrease in inventory	1,605	14	-	-	1,619
Increase in accounts payable	2,658	3,341	40	-	6,039
Increase in other current liabilities	23,440	6,143	-	-	29,583
Other	(1,628)	-	-	-	(1,628)
Net cash provided by (used in) operating activities	198,077	372,815	(42)	-	570,850
Cash flows from investing activities:					
Investment in oil and gas properties	(309,026)	(455,903)	(4)	-	(764,933)
Proceeds from sale of oil and gas properties, net of expenses	5,575	82,355	-	-	87,930
Investment in fixed and other assets	(2,247)	-	-	-	(2,247)
Net cash used in investing activities	(305,698)	(373,548)	(4)	-	(679,250)
Cash flows from financing activities:					
Proceeds from bank borrowings	75,000	-	-	-	75,000
Repayment of bank borrowings	(30,000)	-	-	-	(30,000)
Deferred financing costs	(4,017)	-	-	-	(4,017)
Excess tax benefits	1,493	-	-	-	1,493
Net payments for share based compensation	(2,581)	-	-	-	(2,581)
Net cash provided by financing activities	39,895	-	-	-	39,895
Net change in cash and cash equivalents	(67,726)	(733)	(46)	-	(68,505)
Cash and cash equivalents, beginning of period	105,115	1,659	182	-	106,956
Cash and cash equivalents, end of period	$37,389	$926	$136	$ -	$38,451

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2010
(In thousands of dollars)

	Parent	Guarantor Subsidiary	Non-Guarantor Subsidiary	Eliminations	Consolidated
Cash flows from operating activities:					
Net income (loss)	$96,429	$140,366	($337)	($140,029)	$96,429
Adjustments to reconcile net income (loss) to net cash provided by operating activities:					
Depreciation, depletion and amortization	40,351	206,856	994	-	248,201
Accretion expense	14,503	19,524	442	-	34,469
Deferred income tax provision (benefit)	(28,569)	79,043	-	-	50,474
Settlement of asset retirement obligations	(6,461)	(30,440)	-	-	(36,901)
Non-cash stock compensation expense	5,692	-	-	-	5,692
Excess tax benefits	(299)	-	-	-	(299)
Non-cash derivative income	(324)	-	-	-	(324)
Loss on early extinguishment of debt	1,820	-	-	-	1,820
Non-cash interest expense	858	-	-	-	858
Other non-cash expense	979	-	-	-	979
Non-cash (income) loss from investment in subsidiary	(140,366)	337	-	140,029	-
Change in current income taxes	(10,783)	(88)	-	-	(10,871)
Change in intercompany receivable/payables	349,118	(347,941)	(1,177)	-	-
(Increase) decrease in accounts receivable	(11,556)	61,254	(65)	-	49,633
Decrease in other current assets	18	56	-	-	74
Decrease in inventory	1,848	275	-	-	2,123
Increase (decrease) in accounts payable	(1,045)	272	-	-	(773)
Decrease in other current liabilities	(17,423)	(665)	-	-	(18,088)
Other expenses	1,230	68	-	-	1,298
Net cash provided by (used in) operating activities	296,020	128,917	(143)	-	424,794
Cash flows from investing activities:					
Investment in oil and gas properties	(265,198)	(136,394)	(175)	-	(401,767)
Proceeds from sale of oil and gas properties, net of expenses	25,455	6,180	-	-	31,635
Investment in fixed and other assets	(2,949)	-	-	-	(2,949)
Acquisition of non-controlling interest	-	(1,007)	-	-	(1,007)
Net cash used in investing activities	(242,692)	(131,221)	(175)	-	(374,088)
Cash flows from financing activities:					
Repayment of bank borrowings	(175,000)	-	-	-	(175,000)
Proceeds from issuance of senior notes	375,000	-	-	-	375,000
Deferred financing costs	(11,474)	-	-	-	(11,474)
Redemption of senior subordinated notes	(200,503)	-	-	-	(200,503)
Excess tax benefits	299	-	-	-	299
Net payments for share based compensation	(1,365)	-	-	-	(1,365)
Net cash used in financing activities	(13,043)	-	-	-	(13,043)
Net increase (decrease) in cash and cash equivalents	40,285	(2,304)	(318)	-	37,663
Cash and cash equivalents, beginning of period	64,830	3,963	500	-	69,293
Cash and cash equivalents, end of period	$105,115	$1,659	$182	$ -	$106,956

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.

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

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.

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.

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.

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.

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 natural 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 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-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.

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Board of Directors

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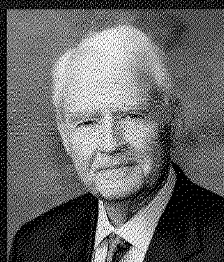

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Taylor Energy Company LLC
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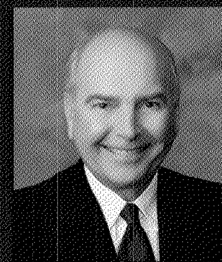

David H. Welch
Stone Energy Corporation
Chairman, President and
Chief Executive Officer

1 Audit Committee *2 Compensation Committee* *3 Nominating and Governance Committee* *4 Reserves Committee*

Corporate Information

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CFO@StoneEnergy.com
NYSE: SGY

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3900 One Shell Square
701 Poydras Street
New Orleans, LA
70139-9869

Annual Meeting
The company's Annual Meeting of Stockholders will be held at 10:00 a.m. on May 23, 2013, at the Windsor Court Hotel, New Orleans, LA.

Transfer Agent and Registrar
Computershare
P.O. Box 43006
Providence, RI 02940-3006
(877) 878-7534
www.computershare.com

Form 10-K
Copies of the company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request to Investor Relations or through the company's website at www.StoneEnergy.com. Quarterly reports and press release information also may be accessed through the website.

Annual CEO Certification
The Annual CEO Certification regarding the New York Stock Exchange's corporate governance listing standards required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was provided to the New York Stock Exchange on June 5, 2012.

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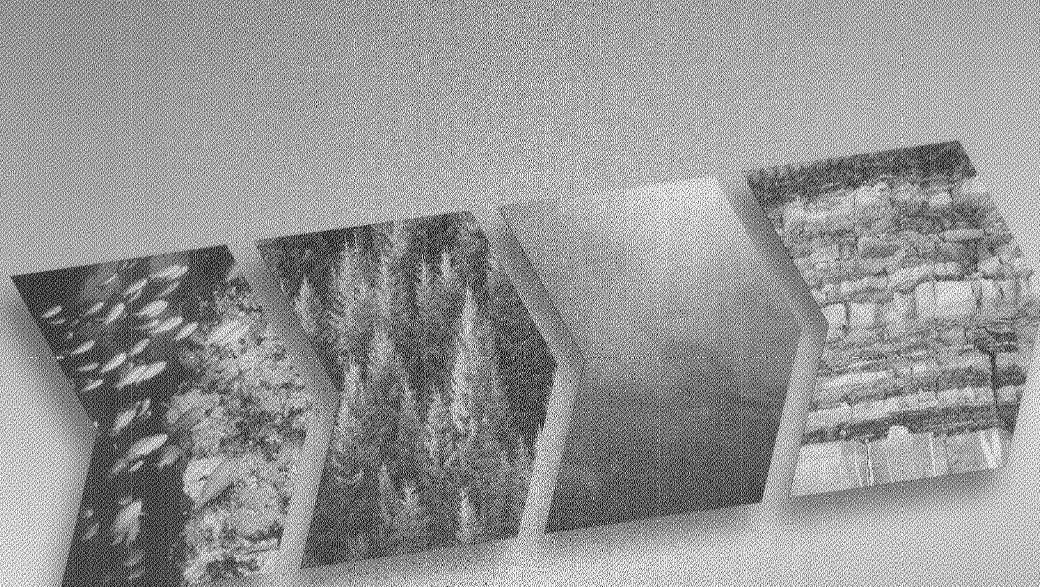

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