SARATOGA RESOURCES INC /TX
Form 10-K
March 10, 2011

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x

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

For the Fiscal Year Ended December 31, 2010

p

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

For the transition period from ____________ to _____________

Commission File No. 1-32955

SARATOGA RESOURCES, INC.

(Exact name of registrant specified in its charter)

Texas	**76-0314489**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

7500 San Felipe, Suite 675, Houston, Texas 77063
(Address of principal executive offices)(Zip code)

Issuer's telephone number, including area code:

(713) 458-1560

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

Title of each class	Name of each exchange on which each is registered
None	None

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

Common Stock, $0.001 par value
(Title of Class)

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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). Yes ¨ No ¨

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

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 definition of accelerated filer, large accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one)

Large accelerated filer o Accelerated filer o Non-accelerated filer o Smaller reporting company ý

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant on June 30, 2010, based on the closing sales price of the registrant s common stock on that date, was approximately $7,331,726. Shares of common stock held by each current executive officer and director and by each person known by the registrant to own 5% or more of the outstanding common stock have been excluded from this computation in that such persons may be deemed to be affiliates.

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

The number of shares of the registrant's common stock, $0.001 par value, outstanding as of March 8, 2011 was 17,323,598.

DOCUMENTS INCORPORATED BY REFERENCE

None.

TABLE OF CONTENTS

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two dimensional, seismic.

bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.

bcf. Billion cubic feet of natural gas.

Behind pipe. Reserves which are expected to be recovered from zones behind casing in existing wells, which require additional completion work or a future recompletion prior to the start of production.

boe. Barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons.

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

Drilling locations. Total gross locations specifically quantified by management to be included in the company s multi-year drilling activities on existing acreage. The company s actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, drilling results and other factors.

Dry hole. A well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Farm-in. An agreement between a participant who brings a property into the venture and another participant who agrees to spend an agreed amount to explore and develop the property and has no right of reimbursement but may gain a vested interest in the venture. A farm-in describes the position of the participant who agrees to spend the agreed-upon sum of money to gain a vested interest in the venture.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. An identifiable layer of rocks named after its geographical location and dominant rock type.

Gross wells. Total number of producing wells in which we have an interest.

Lease. A legal contract that specifies the terms of the business relationship between an energy company and a landowner or mineral rights holder on a particular tract of land.

Leasehold. Mineral rights leased in a certain area to form a project area.

Lease operating expenses. The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

mbbls. Thousand barrels of crude oil or other liquid hydrocarbons.

mboe. Thousand barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids *mcf.* Thousand cubic feet of natural gas.

mcfe. Thousand cubic feet equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

mmbbls. Million barrels of crude oil or other liquid hydrocarbons.

mmboe. Million barrels of crude oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

mmbtu. Million British Thermal Units.

mmcf. Million cubic feet of natural gas.

Net acres, net wells, or net reserves. The sum of the fractional working interests owned in gross acres, gross wells, or gross reserves, as the case may be.

NYMEX. New York Mercantile Exchange.

ngl. Natural gas liquids, or liquid hydrocarbons found in association with natural gas.

Overriding royalty interest. A right to receive revenues, created out of the working interest, from the production of oil and gas from a well free of obligation to pay any portion of the development or operating costs of the well and limited in life to the duration of the lease under which it is created.

Pay. The vertical thickness of an oil and natural gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Possible Reserves. Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of proved plus probable plus possible reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10-percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Probable Reserves. Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50-percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Production. Natural resources, such as oil or gas, taken out of the ground.

Productive well. A well that is found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing reserves. (PDNP). Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods that are not currently being produced.

Proved developed producing reserves (PDP). Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods and that are currently being produced.

5

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable from known reservoirs under current economic and operating conditions, operating methods, and government regulations.

Proved undeveloped reserves (PUD). 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.

PV-10. The discounted present value of the estimated future gross revenue to be generated from the production of proved oil and gas reserves (using pricing assumptions consistent with, and after deducting estimated abandonment costs to the extent required by, SEC guidelines), net of estimated future development and production costs, before income taxes and without giving effect to non-property related expense, discounted using an annual discount rate of 10% and calculated in a manner consistent with SEC guidelines.

Recompletion. The process of re-entering an existing well bore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserve life. A measure of the productive life of an oil and gas property or a group of properties, expressed in years.

Reserves. Oil, natural gas and gas liquids thought to be accumulated in known reservoirs.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalties. The portion of oil and gas retained by the lessor on execution of a lease or the cash value paid by the lessee to the lessor based on a percentage of the gross production from the leased property free and clear of all costs except taxes.

Sand. A geological term for a formation beneath the surface of the earth from which hydrocarbons are produced. Its make-up is sufficiently homogenous to differentiate it from other formations.

Shut-in. A well that has been capped (having the valves locked shut) for an undetermined amount of time. This could be for additional testing, could be to wait for pipeline or processing facility, or could be for a number of other reasons.

Standardized measure. The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development, abandonment, production and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes.

Successful. A well is determined to be successful if it is producing oil or natural gas, or awaiting hookup, but not abandoned or plugged.

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

Working interest. The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. These forwarding-looking statements include without limitation statements regarding our expectations and beliefs about the market and industry, our goals, plans, and expectations regarding our properties and drilling activities and results, our intentions and strategies regarding future acquisitions and sales of properties, our intentions and strategies regarding the formation of strategic relationships, our beliefs regarding the future success of our properties, our expectations and beliefs regarding competition, competitors, the basis of competition and our ability to compete, our beliefs and expectations regarding our ability to hire and retain personnel, our beliefs regarding period to period results of operations, our expectations regarding revenues, our expectations regarding future growth and financial performance, our beliefs and expectations regarding the adequacy of our facilities, and our beliefs and expectations regarding our financial position, ability to finance operations and growth and the amount of financing necessary to support operations. These statements are subject to risks and uncertainties that could cause actual results and events to differ materially. See Item 1A. Risk Factors for a discussion of certain risks. We undertake no obligation to update forward-looking statements to reflect events or circumstances occurring after the date of this annual report on Form 10-K.

As used in this annual report on Form 10-K, unless the context otherwise requires, the terms we, us, the Company, Saratoga and Saratoga Resources refer to Saratoga Resources, Inc., a Texas corporation, and its subsidiaries.

PART I

Item 1.

Business

General

Saratoga Resources, Inc. is an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of natural gas and crude oil properties. Our principal properties were acquired in July 2008 and cover an estimated 33,869 gross acres (31,125 net), substantially all of which are held by production without near-term lease expirations, across 12 fields in the transitional coastline and protected in-bay environment on parish and state leases of south Louisiana. See Harvest Acquisition. Prior to the July 2008 acquisition of our Louisiana properties, our operations were focused on production, development, acquisition and exploitation of various mineral interests in the State of Texas.

We operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code from March 31, 2009 until our exit from bankruptcy on May 14, 2010. See Chapter 11 Reorganization.

Our total proved reserves as of December 31, 2010 were 18.0 MMBoe, consisting of 60.9 Bcf of natural gas and 7.9 MMBbls of oil. The PV-10 of our proved reserves at year-end was $316.0 million before future income taxes, or $235.7 million after future income taxes. Additionally, at year-end we had probable reserves of 10.5 MMBoe, consisting of 38.0 Bcf of natural gas and 4.2 MMBbls of oil.

During 2010, we added 935 MBoe through purchases, extensions, discoveries and revisions and produced 863 MBoe, of which 64% was oil. As of December 31, 2010, we had 54 proved behind pipe and shut-in development opportunities in 8 fields, 92 proved undeveloped opportunities within 37 proposed wells in 5 fields, 51 probable behind pipe and shut-in development opportunities, 33 probable undeveloped opportunities, 13 possible behind pipe and shut-in development opportunities and 21 possible undeveloped opportunities.

Our principal and administrative offices are located at 7500 San Felipe, Suite 675, Houston, Texas. Our telephone number is (713) 458-1560.

Harvest Acquisition

In July 2008, we acquired our principal properties through the acquisition (the Harvest Acquisition) of all of the membership interest in Harvest Oil & Gas, LLC (Harvest Oil) and The Harvest Group, LLC (Harvest Group and, together with Harvest Oil, the Harvest Companies).

As consideration for the membership interests in the Harvest Companies, we paid to the former members of the Harvest Companies a combined purchase price of $105.7 million in cash and issued 4.9 million shares of our common stock. The cash portion of the purchase price included $33.7 million and $30.0 million, respectively, paid by the Harvest Companies to pay a note payable to Macquarie Bank Limited (Macquarie) and to obtain a release of a net profits interest and an overriding royalty interest in the properties of the Harvest Companies held by Macquarie and its affiliates, respectively, which amounts we paid directly to Macquarie on behalf of the Harvest Companies at closing. Of the 4.9 million shares of common stock issued in the acquisitions, 3.3 million shares were issued directly to Macquarie Americas Corp., an affiliate of Macquarie, pursuant to an agreement between Macquarie and the members of the Harvest Companies relating to the release of the net profits interest and overriding royalty interest held by Macquarie.

In conjunction with the Harvest Acquisition, and to finance the acquisition and post-acquisition operations, in July 2008, we entered into a Credit Agreement (the 2008 Term Credit Agreement) with Wayzata Investment Partners, LLC (Wayzata) and a separate Credit Agreement (the 2008 Revolving Credit Agreement) with Macquarie. We borrowed $97.5 million under the 2008 Term Credit Agreement and approximately $12.5 million under the 2008 Revolving Credit Agreement to pay the purchase price of the Harvest Acquisition and associated costs.

The Harvest Companies were independent oil and natural gas companies engaged in the production, development, and exploitation of natural gas and crude oil properties, together covering an estimated 33,000 gross acres (30,000 net) across 11 fields in the transitional coastline and protected in-bay environment on parish and state leases of south Louisiana.

We retained key members of the management and operational teams of the Harvest Companies and, following the Harvest Acquisition, shifted the focus of our operations to the continued development and operations of the various holdings of the Harvest Companies.

Chapter 11 Reorganization

Beginning late in the third quarter of 2008, accelerating during the fourth quarter of 2008, and continuing into the first quarter of 2009, our operations were materially adversely affected by a sharp drop in the projected demand for, and price of, oil and natural gas that accompanied the severe disruptions in credit and financial markets that resulted in economic contraction in the U.S. and globally. While we entered into hedging transactions to reduce our exposure to commodity price risks, we were still subject to risks associated with declines in the price of oil and natural gas relating to unhedged production.

On July 14, 2008, the day of closing for the Harvest Acquisitions, crude oil prices closed at $145.66 per barrel, while the spot price for natural gas averaged $11.45 per MCF. Oil had remained above $100 per barrel for sixteen consecutive weeks at that time. Equivalent oil and natural gas prices in March 2009 were 63% and 65%, respectively, lower than they were when we closed the Harvest Acquisitions and entered into the Credit Agreements with Wayzata and Macquarie.

On February 26, 2009, Wayzata issued a notice of default wherein it alleged nine non-monetary breaches of the 2008 Term Credit Agreement, or events of default. Wayzata, in its notice of default, did not exercise any of its rights under the 2008 Term Credit Agreement, but expressly reserved the right to do so. We disputed Wayzata s notice of default as premature and based on incomplete data and failure to take into account various developments and circumstances.

Macquarie also issued a notice of default dated February 26, 2009, which was expressly based on Wayzata s notice of default. The Macquarie notice of default was triggered by cross default provisions in the 2008 Revolving Credit Agreement defining an event of default as an event or condition occurring which permits the holder of any material debt to accelerate that obligation. Macquarie stated in its notice of default that it was not initiating any action to exercise its rights and remedies available, though its right to do so was expressly reserved. As a result of the Macquarie notice of default, Macquarie rejected our requests to access additional credit available under the 2008 Revolving Credit Agreement, which restriction of credit impaired our ability to continue our development program. We disputed the Macquarie notice of default.

Following the receipt of the referenced notices of default from Wayzata and Macquarie, we entered into discussions with Wayzata seeking an amicable resolution and forbearance in order to cure the alleged covenant defaults and to access available credit under our 2008 Revolving Credit Agreement to continue pursuit of our ongoing drilling, workover and recompletion program. Despite management s efforts, management and our board of directors determined that a bankruptcy court reorganization would offer the best means of addressing our existing debt structure and realization of the long-term anticipated benefits of our drilling, workover and recompletion program. To that end, on March 31, 2009 (the Petition Date), we, and our principal operating subsidiaries, filed voluntary Chapter 11 petitions in the U.S. Bankruptcy Court for the Western District of Louisiana.

As a result of the Chapter 11 filing, we continued to operate our business and manage our properties as debtors-in-possession, although our development activities were substantially curtailed due to limited access to financing, and engaged in negotiations and other efforts to resolve issues with our lenders, in particular we sought to restructure the 2008 Term Credit Agreement. On April 19, 2010, the Bankruptcy Court entered an order confirming our Modified Third Amended Plan of Reorganization (the Plan). The Plan became effective and we exited bankruptcy on May 14, 2010 (the Effective Date), following amendment of our existing debt facilities.

Under the Plan (1) the 2008 Revolving Credit Agreement was amended (the Amended Revolving Credit Agreement) as to maturity date and interest rate and claims under the revolving credit agreement were allowed in the amount of $23.5 million (including outstanding letters of credit), of which $5.5 million was paid on exit from bankruptcy: (2) the 2008 Term Credit Agreement was amended and restated (the Amended and Restated Term Credit Agreement) as to maturity and interest rate and claims under the term credit agreement were allowed in the amount of $127.5 million; (3) our other creditors were paid, or will be paid, in whole; (4) amounts owing on notes payable to officers will be payable in full, including compound accrued interest, in forty months; (5) a warrant to purchase 2,000,000 shares of our common stock was issued to the administrative agent for the revolving and term credit facilities; the warrant will be exercisable at $0.01 per share and will vest 111,111 shares on exit from bankruptcy and 111,111 shares per month thereafter; and (6) 483,310 shares of common stock were issued pro rata among the oil lien claim creditors, other secured creditors and unsecured creditors; all more fully described as follows:

Amended Revolving Credit Agreement

On May 14, 2010, we entered into an Amended Revolving Credit Agreement reflecting the terms described in the Plan. Under the Amended Revolving Credit Agreement, our revolving credit facility was revised to provide for total outstanding principal under the facility of $18.0 million, including $10.2 million in letters of credit and after payment of $5.5 million. No further borrowings can be made under the Amended Revolving Credit Agreement.

The Amended Revolving Credit Agreement provides for payments of interest only on a monthly basis at a floating rate of prime plus 2% with all amounts owing under the agreement being due and payable in full on April 30, 2012.

Amended and Restated Term Credit Agreement

On May 14, 2010, we entered into an Amended and Restated Term Credit Agreement reflecting the terms described in the Plan. Under the Amended and Restated Term Credit Agreement, our term credit facility was revised to reflect the total amount borrowed and owing thereunder of $127.5 million and to provide for accrual of interest at 11.25% per annum (reduced from 20.00% pre-bankruptcy) payable interest only on a monthly basis with all amounts owing under the agreement being due and payable in full on April 30, 2012.

Wayzata Warrant and Creditor Shares

On or shortly after May 14, 2010, pursuant to the Plan, we issued (1) a warrant in favor of Wayzata to purchase up to 2,000,000 shares of our common stock exercisable at $0.01 per share, which warrant vests and is exercisable 111,111 shares on the Effective Date and 111,111 shares per month over the following seventeen months unless all amounts payable under the Amended and Restated Term Credit Agreement are paid in full, in which case any unvested portion of the warrant on the date of repayment in full will be forfeited, and (2) 483,310 shares of common stock pro rata among oil lien claim creditors, other secured creditors and unsecured creditors.

Other Secured Creditors and Unsecured Creditors

With respect to mineral royalties owing pursuant to an audit conducted by the Louisiana Department of Mineral Resources, claims totaling $1.7 million were allowed and are payable in twenty four monthly installments of $71,235. With respect to substantially all other secured and unsecured creditors (other than management notes), all allowed claims of unsecured creditors and oil lien claim creditors will be paid in full of which unsecured creditors received 75% in cash on exit from bankruptcy and the balance is payable in quarterly installments over one year and oil lien claim creditors received 80% in cash on exit from bankruptcy and the balance is payable in quarterly installments over one year.

Management Notes

With respect to claims (the Management Claims) by Thomas F. Cooke and Andrew C. Clifford, members of management of our company, pursuant to existing promissory notes from Saratoga, from and after the Effective Date, the Management Claims will be payable in full, including compound accrued interest, in forty months.

Equity Holders

Subject to the issuance of the warrant to Wayzata and the issuance of shares to certain creditors under the Plan, as described herein, each holder of our equity securities, including common stock, warrants and options, retained identical interests in our company following the Effective Date, provided, however, that holders of equity securities will receive no dividends or distributions in respect of their equity holdings unless and until the holders of all allowed claims have been paid in full in cash in accordance with the Plan.

Our Strategy

During 2010, we continued to pursue our strategy of focused development of our portfolio of assets in the shallow transitional coastline and protected in-bay waters of Louisiana with the objective of increasing our reserves, production and cash flow. Our development strategy was carried out at a curtailed level pending, and immediately following, our emergence from bankruptcy in May 2010. The following are key elements of our strategy:

Grow Through Exploitation, Development and Exploration of Our Properties. We intend to focus our development and exploration efforts on our Louisiana properties. We believe that our extensive held by production acreage position will allow us to grow organically through lower-risk development drilling. We have attractive opportunities to expand our reserve base through field extensions, delineating shallower and deeper formations within existing fields and exploratory drilling. Most of our locations also offer multiple stacked reservoir objectives with substantial behind pipe potential.

Actively Manage the Risks and Rewards of Our Drilling Program. We operate over 90% of the wells that comprise our proved reserves as of December 31, 2010, and we own net revenue interests in our properties that average approximately 72% on a net acreage leasehold basis. We believe operating our properties is important because it allows us to control the timing and costs in our drilling budget, as well as control operating costs and marketing of production. In addition, our high level of net revenue interests enhances our returns from each successful well we drill by giving us a higher percentage of cash flow generated. We believe our high level of net revenue interests provides us with a unique opportunity to retain a substantial economic interest in higher risk wells while mitigating the risk associated with these projects through farm-outs or promoted deals. Additionally, we will review and rationalize our properties on a continuous basis in order to optimize our existing asset base.

Leverage Technological Expertise. We believe that 3-D seismic analysis and other advanced technologies and production techniques are useful tools that help improve drilling results and ultimately enhance our production and returns. At December 31, 2010, we either owned or had licensed 3-D seismic data covering over 450 square miles in the Grand Bay and other fields and intend to seek more seismic data in the future. We intend to utilize these technologies and production techniques in exploring for, developing and exploiting oil and natural gas properties to help us reduce drilling risks, lower finding costs and provide for more efficient production of oil and natural gas from our properties. We believe that the use of these technologies enhances our probability of locating and producing reserves that might not otherwise be discovered.

Pursue Opportunistic Acquisitions. We continually review opportunities to acquire producing properties, leasehold acreage and drilling prospects. During 2010, we expanded our acreage position with the acquisition of three State of Louisiana leases adjacent to our existing acreage and infrastructure and including a producing well that was plugged and abandoned as a result of mechanical problems experienced as a result of Hurricane Katrina. We believe our relationship with Macquarie, which introduced us to the Harvest Companies, will provide us with first look opportunities relating to potential future acquisitions. When identifying acquisition candidates, we focus primarily on underdeveloped assets with significant growth potential. We seek acquisitions that will allow us to enhance and exploit properties without assuming significant geologic, exploration or integration risk.

Properties

The following table describes our properties and production profile at December 31, 2010.

Property	Barrels of Oil Equivalent (MBoe)	% Oil	PV-10(1) (dollars in thousands)	Net Acreage (estimated)	Net Revenue Interest %	Net Producing Wells	Reserve Life Index(3) (Years)
Grand Bay	5,199	77%	$ 113,338	15,479	19-79%	61	18
Vermilion 16	8,658	20%	122,398	4,095	75-83%	1	*
Main Pass 46	1,897	29%	27,459	1,663	64-78%	3	*
Other	2,272	69%	52,773	9,888	31-88%	33	4
All Properties	18,026	44%	$ 315,968	31,125		98	22

* Not meaningful

(1)

Based on unweighted average benchmark prices as of the first of each month during 2010 of $79.43 per Bbl and $4.38 per MMBtu and before future income taxes. The average realized price after applying differential to unweighted average benchmark prices was $78.79 per Bbl and $5.11 per Mcf.

(2)

Average net production for 2010.

(3)

Calculated by dividing total net proved reserves by current net production for December 2010.

Grand Bay Field. The Grand Bay Field is located in Plaquemines Parish, approximately 70 miles southeast of New Orleans, Louisiana. It is situated in the transitional coastline and protected in-bay environment on parish and state leases on the east side of the Mississippi River. Gulf Oil discovered the field in 1938. Harvest Oil and Gas acquired the field in April 2005. A farmout was granted to Clayton Williams Energy, Inc. prior to the acquisition of the field by Harvest Oil, covering approximately 2,000 gross acres in the north-west portion of the field. Our ownership in Grand Bay ranges from 25% to 100% working interest and 19% to 79% net revenue interest. We are the operator of all of the Grand Bay Field property not subject to the Clayton Williams Energy, Inc. farmout.

The Grand Bay Field is a large, faulted anticlinal structure. It lies on a northwest/southeast trending, deep-seated salt ridge that also sets up Coquille Bay Field, to the northwest, and Romere Pass Field, to the southeast. Trapping is predominantly from intersecting fault closures associated with this anticlinal feature, although there are cases of stratigraphic trapping. The predominant drive mechanism is water drive. Some productive formations are clean, blocky sands with high-resistivity pay. Other laminated, low-resistivity sands are also productive. Shallow sands are predominantly gas-filled and associated with anomalous amplitudes. There are additional shallow amplitudes in the field that have not yet been drilled or logged.

Production has been from over 60 different sands between approximately 1,600 and 13,500 feet, subsea. We are evaluating shallow Pliocene gas potential as well as deeper oil and gas potential in the Tex W, Big Hum, Cris I and Lower Tertiary levels below 13,500 feet. Collarini Engineering completed a full field study of the Grand Bay Field in mid-2010. Our leases in the Grand Bay Field, which are all held by production, cover an estimated 16,999 gross and 15,479 net acres. We own a license to 90 square miles of high quality, proprietary 3-D seismic data, originally acquired by Greenhill in 1994 and reprocessed by Saratoga in 2008. We are using this dataset to better locate proposed development wells as well as delineating shallow gas exploration and deep oil and gas targets below existing production.

Facilities include a central compressor station, four tank batteries, numerous gas lift manifolds and a bunk house, from which all field operations are controlled. Low pressure, high Btu-content gas at Grand Bay Field is used to lift oil and high pressure, lower Btu gas. We entered into a production tie-in agreement with Apache in late 2008 that improves field efficiencies and we continue to look for ways to decrease operating costs in all fields.

Vermilion 16 Field. The Vermilion 16 Field is located in the transitional coastline and protected in-bay environment on state leases offshore Vermilion Parish, approximately 40 miles south of Lafayette, Louisiana. It is situated in approximately 12 feet of water, 0.5 miles offshore in the Gulf of Mexico. Saratoga is operator with 100% working interest with a net revenue interest ranging from 75% to 83%.

The field is a four-way rollover anticline on the downthrown side of a down-to-the-south fault. There are multiple stacked reservoirs within the field. Pulsed neutron logging has been carried out to identify unswept hydrocarbons within existing wellbores. There are five wellbores associated with this field and a number of proved undeveloped drilling locations within the field. NuTech Energy Alliance completed a full field study of the Vermillion 16 Field in early 2010. We licensed 25 square miles of 3D seismic data in 2008 and will use this data to better locate proposed development wells.

Facilities include a central facility and there are five wellbores associated with the field. Production from McMoRan Oil and Gas, LLC s King Kong wells, located 1.2 miles to the southwest of our platform in adjoining SL 17159, is processed at the Vermilion 16 platform, for which we receive revenues. The existing seven state leases cover an estimated 4,095 gross acres (4,095 net) and are all held by production.

11

Main Pass 46 Field. The Main Pass 46 Field is located in the transitional coastline and protected in-bay environment on state leases offshore Plaquemines Parish, approximately 80 miles south-southeast of New Orleans, Louisiana. It is situated in approximately 6 feet of water, immediately north of Grand Bay Field. Saratoga is operator with 100% working interest with a net revenue interest ranging from 64% to 78%.

The field is a faulted anticlinal structure with outlying stratigraphic traps. There are multiple stacked reservoirs within the field. There are a large number of proved undeveloped drilling locations within the field. The Main Pass 46 Field is covered by the 90 square mile proprietary 3-D Grand Bay survey.

Facilities include a central facility and there are three wellbores associated with the field. The existing four state leases cover an estimated 1,663 gross acres (1,663 net) and are all held by production. Most of the proved undeveloped opportunities are located within Grand Bay State Lease 195.

Other Fields. We hold interests in nine other fields, all in the transitional coastline and protected in-bay environment on state leases in Plaquemines, St. Bernard and St. Mary parishes, southern Louisiana, with working interests ranging from 40% to 100%. The net revenue interest ranges from 31% to 88%, except for Breton Sound 31 Field, where we have a 36% net profits interest, and Main Pass 47 Field, where we have a 7.5% overriding royalty interest in one producing well. The leases, which are mostly held by production, cover an estimated 11,112 gross acres (9,888 net).

Among the other fields in which we hold interests are the Main Pass and Breton Sound fields, which are a series of stratigraphic trap-type fields in the Middle Miocene trend that were discovered with 3-D seismic technology. The reservoir drive mechanisms are water drive and combination water drive/pressure depletion. Saratoga has licensed the entire SEI Breton Sound 3-D survey that covers approximately 400 square miles.

Field Infrastructure

We own certain infrastructure assets serving our properties including approximately 85 miles of pipelines connecting several of the fields as well as outlying wellheads. There are six platform facilities plus 109 active producing wellbores associated with these fields, including ten salt water disposal wells. In addition to serving our wells and improving field economics, we generate revenues from providing access to our infrastructure assets to third parties. Facilities at Grand Bay include four tank batteries, a compressor station, various flowlines and a bunk house. We receive third-party processing and production handling revenues from Clayton Williams Energy, Inc., McMoRan Oil and Gas, LLC, and Martin-Marks Minerals, LLC.

12

Natural Gas and Oil Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2010, our estimated net proved oil and natural gas reserves, the estimated present value (discounted at an annual rate of 10%) of estimated future net revenues before future income taxes (PV-10) and after future income taxes (Standardized Measure) of our proved reserves and our estimated net probable and possible oil and natural gas reserves, each prepared in accordance with assumptions prescribed by the Securities and Exchange Commission (SEC). All of our reserves are located in the United States.

The PV-10 value is a widely used measure of value of oil and natural gas assets and represents a pre-tax present value of estimated cash flows discounted at ten percent. PV-10 is considered a non-GAAP financial measure as defined by the SEC. We believe that our PV-10 presentation is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves before taking into account the related future income taxes, as such taxes may differ among various companies because of differences in the amounts and timing of deductible basis, net operating loss carryforwards and other factors. We believe investors and creditors use our PV-10 as a basis for comparison of the relative size and value of our proved reserves to the reserve estimates of other companies. PV-10 is not a measure of financial or operating performance under GAAP and is not intended to represent the current market value of our estimated oil and natural gas reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

		Reserves [1]	
Reserve category	**Oil**	**Natural Gas**	**Total [2]**
	(MBbls)	**(MMcf)**	**(MBoe)**
Proved			
Developed			
Producing	1,501	3,308	2,052
Shut-in	35	38	41
Behind Pipe	1,121	1,767	1,416
Total Proved Developed	2,657	5,113	3,509
Undeveloped	5,222	55,763	14,516
Total Proved	7,879	60,876	18,025
Probable[3]			
Developed	847	5,158	1,707
Undeveloped	3,357	32,886	8,838
Possible[3]			
Developed	537	1,281	750

Undeveloped	12,611	100,457	29,354

PV-10 [(1)]	$ 315,968
Standardized Measure [(4)]	$ 235,657

(1)

In accordance with applicable financial accounting and reporting standards of the SEC, the estimates of our proved reserves and the PV-10 set forth herein reflect estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions at December 31, 2010. For purposes of determining prices, we used the unweighted arithmetical average of the prices on the first day of each month within the 12-month period ended December 31, 2010 which were $79.43 per Bbl and $4.38 per MMbtu. The prices utilized for purposes of estimating our proved reserves were $78.79 per Bbl and $5.11 per Mcf, after adjustment by property for energy content, quality, transportation fees and regional price differentials. The prices should not be interpreted as a prediction of future prices. The amounts shown do not give effect to non-property related expenses, such as corporate general administrative expenses and debt service, future income taxes or to depreciation, depletion and amortization.

(2)

Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

(3)

Probable and possible reserves have not been discounted for the risk associated with future recovery.

(4)

The Standard Measure differs from PV-10 only in that the Standard Measure reflects estimated future income taxes.

Due to the inherent uncertainties and the limited nature of reservoir data, proved, probable and possible reserves are subject to change as additional information becomes available. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the SEC, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

In estimating probable and possible reserves, it should be noted that those reserve estimates inherently involve greater risk and uncertainty than estimates of proved reserves. While analysis of geoscience and engineering data provides reasonable certainty that proved reserves can be economically producible from known formations under existing conditions and within a reasonable time, probable reserves involve less certainty with reserves supporting a probable classification from a probabilistic analysis where those reserves are as likely as not to be recovered. Possible reserves involving even less certainty than probable reserves and possible classification is supported when there is at least a 10% probability that total quantities recovered equal or exceed proved plus probable plus possible reserve estimates.

Alternative Pricing Case. We use forward-looking market-based data in developing our drilling plans, assessing our capital expenditure needs and projecting future cash flows. We believe that using the 10-year average NYMEX strip prices yields a better indication of the likely economic producibility of proved reserves than the trailing average 12-month price required by SEC reserves rules or a period end spot price, as used under the SEC rules before December 31, 2009. The table below compares our estimated proved reserves and associated present value (discounted at an annual rate of 10%) of estimated future revenue before income taxes using the 2010 12-month average prices reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2010.

	Oil (MMbls)	**Gas (MMcf)**	**Total (Mboe)[1]**	**PV-10 ($000s)**
SEC Case	7,879	60,876	18,025	$ 315,968
NYMEX Strip Price Case [2]	8,088	62,637	18,528	$ 437,938

(1)

Natural gas is converted on the basis of six Mcf of gas per one barrel of oil equivalent.

(2)

The NYMEX Strip Pricing Case discloses our estimated proved reserves using future market-based commodities prices instead of the average historical prices used in the SEC Case. Under the NYMEX Strip Pricing Case, we used futures prices, as quoted on the New York Mercantile Exchange (NYMEX) on December 31, 2010, as benchmark prices for 2010 through 2016, and continued to use the 2016 futures price for all subsequent years. These benchmark prices were further adjusted for quality, energy content, transportation fees and other price differentials specific to our properties, resulting in an average adjusted price of $92.52 per barrel of oil and $6.41 per Mcf of natural gas over the remaining life of the proved reserves. There is no change to our cost or other assumptions between this higher price scenario and those used in the estimation of our reported reserves.

Reserve Estimation Process, Controls and Technologies

The reserve estimates, including PV-10 and Standard Measure estimates, set forth above were prepared by Collarini Associates.

These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry and in accordance with SEC financial accounting and reporting standards.

We maintain an internal staff of engineering and geoscience professionals who work closely with Collarini Associates in connection with their preparation of our reserve estimates, including assessing the integrity, accuracy and timeliness of the methods and assumptions used in this process. Our internal technical team members meet with Collarini Associates periodically throughout the year to discuss the assumptions and methods used in the reserve estimation process. We provide historical information to Collarini Associates for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. The activities of our internal staff are led and overseen by our President, a degreed petroleum geologist/geophysicist with over 32 years of technical experience involving petroleum reserve assessment and estimation and geoscience-based evaluation. He is assisted by our Asset Evaluation Manager, who has over 26 years of technical experience in petroleum engineering and reservoir evaluation and analysis. Together, these individuals direct the activities of our internal engineering and geosciences staff who coordinate with our accounting and other departments to provide the appropriate data to Collarini Associates in support of the reserve estimation process and to assure that information derived from Collarini Associates reports is properly disclosed in our reports.

Collarini Associates is an independent Houston and New Orleans-based professional engineering firm specializing in technical and financial evaluation of oil and gas assets. Collarini Associates report was prepared under the direction of Collarini Associates President and Engineering Manager. Collarini Associates Engineering Manager holds a B.S. in petroleum engineering from Texas A&M University, is a registered professional engineer and has approximately 30 years of experience in production engineering, reservoir engineering, acquisitions and divestments, field operations and management.

The SEC s rules with respect to technologies that a company can use to establish reserves, effective for years ending after December 31, 2008, allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Collarini used a combination of production and pressure performance, simulation studies, offset analogies, seismic data and interpretation, geophysical logs and core data to calculate our reserves estimates.

Proved Undeveloped Reserves

As of December 31, 2010, our proved undeveloped reserves totaled 5.2 MMBbls of oil and 55.8 Bcf of natural gas, for a total of 14.5 MMBoe compared to 4.6 MMBbls of oil and 52.8 Bcf of natural gas, for a total of 13.4 MMBoe as of December 31, 2009. The increase in our proved undeveloped reserves was attributable to leasing activities and completion of our field studies.

All of our proved undeveloped reserves at December 31, 2010 were associated with our Louisiana properties.

We incurred no costs relating to the development of proved undeveloped in 2010 and 2009. Our development of proved undeveloped reserves was deferred during 2010 and 2009 due to our operation, through May 2010, as debtor-in-possession during the pendency of our bankruptcy which limited our access to financing to support development activities.

Estimated future development costs relating to the development of proved developed reserves are projected to be approximately $27 million in 2011 and are expected to be fully funded through cash on hand and projected operating cash flow.

All proved undeveloped locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2015. None of our proved undeveloped locations have been booked for longer than five years.

Production, Price and Production Cost History

The table below sets forth certain information regarding the production volumes, average prices received and average production costs associated with our sale of oil and natural gas for the three years ended December 31, 2010.

	2008[2]	2009	2010
Net Production:			
Oil (Bbl)	571,975	626,900	550,000
Natural gas (Mcf)	1,612,470	2,114,600	1,882,800
Combined volumes (Boe)	840,720	979,333	863,800
Average sales price per Boe	$ 81.95	$ 48.39	$ 61.05
Average production cost per Boe[1]	$ 33.33	$ 20.29	$ 18.82

(1)

Average production cost per Boe excludes severance taxes.

(2)

Pro forma 2008 information prior to July 14, 2008, the date of the Harvest Acquisitions, reflects the combined operations of the Harvest Companies. Information with respect to the Company prior to Harvest Acquisitions is not material and has been omitted.

Drilling Activity

Historical

The following tables sets forth, for the two years ended December 31, 2010, the number of gross and net productive and dry exploratory and developmental wells completed, regardless of when drilling was initiated (all wells are located in the United States). Productive wells are wells that are found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

	Year Ended December 31,			
	2009		2010	
	Gross	Net	Gross	Net
Development				
Productive	1	1	-	-
Dry	-	-	-	-
Exploratory				
Productive	-	-	-	-
Dry	-	-	-	-
Total				
Productive	1	1	-	-
Dry	-	-	-	-

In addition to the wells completed, as reflected in the above table, during 2009 we completed recompletion and/or workover operations on five wells and, during 2010, we completed recompletion and/or workover operations on 57 wells.

Drilling activities during 2009, and through our exit from bankruptcy in May 2010, were substantially curtailed by our operations as debtor-in-possession. Drilling activities during 2009 and 2010 were also curtailed by our inability to draw on our revolving credit facility.

The foregoing information should not be considered indicative of future drilling performance, nor should it be assumed that there is any necessary correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered by us. We do not own any drilling rigs and all of our drilling activities are conducted by independent drilling contractors.

Present Activities

At December 31, 2010, no wells were being drilled and no recompletion and/or workover operations were being conducted.

Delivery Commitments

At December 31, 2010, we had no commitments to provide fixed and determinable quantities of oil and gas under contracts or agreements.

Hedging Activities

Until February 2010, we maintained an active commodity hedging program to mitigate the risks of the natural gas and oil price volatility. Under the terms of our prior credit facilities, we were required to hedge not less than 60% nor more than 80% of our oil and natural gas production on a forward 12-month basis using a combination of swaps, cashless collars and other financial derivative instruments with creditworthy counterparties. In February 2010, the administrative agent under our credit agreements liquidated all of our existing hedges notwithstanding the requirement of our credit agreements to maintain hedges. Pursuant to the Amended Revolving Credit Agreement, on and after May 14, 2010, we may hedge up to 60% of production. At December 31, 2010, we had no hedges in place. Subject to market conditions, we intend to evaluate reinstituting an active hedging program consistent with our Amended Revolving Credit Agreement. For additional information on our hedging activities, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

Productive Wells

The following table sets forth information with respect to our ownership interest in productive wells, all of which are located in the United States, as of December 31, 2010:

	Gross	Net
Oil wells	92.0	79.8
Gas wells	19.0	18.2
Total	111.0	98.0

Productive wells are producing wells and wells mechanically capable of production. A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as whole numbers and fractions thereof. Wells with multiple completions are counted as one well in the table above. The total gross wells at December 31, 2010 included one well with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth information with respect to our gross and net developed and undeveloped oil and natural gas acreage under lease as of December 31, 2010, all of which is located in the United States in transitional coastline and in-bay environments on parish and state leases in south Louisiana:

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross	Net	Gross	Net	Gross	Net
31,997	29,253	1,872	1,872	33,869	31,125

Developed acreage is comprised of leased acres that are within an area spaced by or assignable to a productive well. Undeveloped acreage is comprised of leased acres with defined remaining terms and not within an area spaced by or assignable to a productive well.

As is customary in the oil and natural gas industry, we can generally retain our interest in undeveloped acreage by drilling activity that establishes commercial production sufficient to maintain the leases or by paying delay rentals during the remaining primary term of leases. The oil and natural gas leases in which we have an interest are for varying primary terms and, if production under a lease continues from our developed lease acreage beyond the primary term, we are entitled to hold the lease for as long as oil or natural gas is produced.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth, as of December 31, 2010, the expiration periods of the gross and net acres that are subject to leases summarized in the above table of undeveloped acreage.

	Undeveloped Acres Expiring	
Twelve Months Ending:	**Gross**	**Net**
December 31, 2011	252	252
December 31, 2012	1,084	1,084
December 31, 2013	536	536
December 31, 2014	-	-
December 31, 2015 and later	-	-
Total	1,872	1,872

Marketing and Customers

Effective April 1, 2010, we entered into a Natural Gas, Crude and Processing Marketing/Administration Agency Agreement pursuant to which Transparent Energy Services, Inc. markets substantially all of our oil and natural gas production. Prior to April 1, 2010, substantially all of our oil and natural gas production was marketed by Professional Oil and Gas Marketing, LLC.

Sales of oil and gas production to Conoco, Shell and Chevron accounted for 11%, 68% and 16%, respectively of our consolidated revenues in 2010. We believe that the loss of Conoco, Shell or Chevron would not have a material adverse effect on us because alternative purchasers are readily available.

Competition

We encounter intense competition from other oil and gas companies in all areas of our operations, including the acquisition of producing properties and undeveloped acreage. Our competitors include major integrated oil and gas companies, numerous independent oil and gas companies and individuals. Many of our competitors are large, well-established companies with substantially larger operating staffs and greater capital resources and have been engaged in the oil and gas business for a much longer time than our company. These companies may be able to pay more for productive oil and gas properties, exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Employees

As of December 31, 2010, we had 30 full time employees. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We believe our relationships with our employees are good. From time to time, we utilize the services of independent contractors to perform various field and other services.

Regulatory Matters

Regulation of Oil and Gas Production, Sales and Transportation

The oil and gas industry is subject to regulation by numerous national, state and local governmental agencies and departments. Compliance with these regulations is often difficult and costly and noncompliance could result in substantial penalties and risks. Most jurisdictions in which we operate also have statutes, rules, regulations or guidelines governing the conservation of natural resources, including the unitization or pooling of oil and gas properties and the establishment of maximum rates of production from oil and gas wells. Some jurisdictions also require the filing of drilling and operating permits, bonds and reports. The failure to comply with these statutes, rules and regulations could result in the imposition of fines and penalties and the suspension or cessation of operations in affected areas.

We operate various gathering systems and pipelines servicing the areas in which we operate. The United States Department of Transportation and certain governmental agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities by prescribing standards. However, based on current standards concerning transportation and storage activities and any proposed or contemplated standards, we believe that the impact of such standards is not material to our operations, capital expenditures or financial position. All of our sales of our natural gas are currently deregulated, although governmental agencies may elect in the future to regulate certain sales.

Environmental Regulation

Various federal, state and local laws and regulations relating to the protection of the environment, including the discharge of materials into the environment, may affect our exploration, development and production operations and the costs of those operations. These laws and regulations, among other things, govern the amounts and types of substances that may be released into the environment, the issuance of permits to conduct exploration, drilling and production operations, the discharge and disposition of generated waste materials and waste management, the reclamation and abandonment of wells, sites and facilities, financial assurance under the Oil Pollution Act of 1990 and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities for noncompliance and for any contamination resulting from our operations and may require the suspension or cessation of operations in affected areas.

The environmental laws and regulations applicable to us and our operations include, among others, the following United States federal laws and regulations:

Clean Air Act, and its amendments, which govern air emissions;

Clean Water Act, which governs discharges to waters of the United States;

Comprehensive Environmental Response, Compensation and Liability Act, which imposes liability where hazardous releases have occurred or are threatened to occur (commonly known as Superfund);

Resource Conservation and Recovery Act, which governs the management of solid waste;

Oil Pollution Act of 1990, which imposes liabilities resulting from discharges of oil into navigable waters of the United States;

Emergency Planning and Community Right-to-Know Act, which requires reporting of toxic chemical inventories;

Safe Drinking Water Act, which governs the underground injection and disposal of wastewater; and

U.S. Department of Interior regulations, which impose liability for pollution cleanup and damages.

We routinely obtain permits for our facilities and operations in accordance with these applicable laws and regulations on an ongoing basis. There are no known issues that have a significant adverse effect on the permitting process or permit compliance status of any of our facilities or operations.

The ultimate financial impact of these environmental laws and regulations is neither clearly known nor easily determined as new standards are enacted and new interpretations of existing standards are rendered. Environmental laws and regulations are expected to have an increasing impact on our operations. In addition, any non-compliance with such laws could subject us to material administrative, civil or criminal penalties, or other liabilities. Potential permitting costs are variable and directly associated with the type of facility and its geographic location. Costs, for example, may be incurred for air emission permits, spill contingency requirements, and discharge or injection permits. These costs are considered a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with government regulations.

We are committed to the protection of the environment throughout our operations and believe our operations are in substantial compliance with applicable environmental laws and regulations. We believe environmental stewardship is an important part of our daily business and will continue to make expenditures on a regular basis relating to environmental compliance. We maintain insurance coverage for spills, pollution and certain other environmental risks, although we are not fully insured against all such risks. The insurance coverage maintained by us provides for the reimbursement to us of costs incurred for the containment and clean-up of materials that may be suddenly and accidentally released in the course of our operations, but such insurance does not fully insure pollution and similar environmental risks. We do not anticipate that it will be required under current environmental laws and regulations to expend amounts that will have a material adverse effect on our consolidated and combined financial position or our results of operations. However, since environmental costs and liabilities are inherent in our operations and in the operations of companies engaged in similar businesses and since regulatory requirements frequently change and may become more stringent, there can be no assurance that material costs and liabilities will not be incurred in the future. Such costs may result in increased costs of operations and acquisitions and decreased production.

Climate Change Legislation and Greenhouse Gas Regulation

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill. The U.S. Senate s version, The Clean Energy Jobs and American Power Act, or the Boxer-Kerry Bill, was introduced, but has not passed. Although these bills include several differences that require reconciliation before becoming law, both bills contain the basic feature of establishing a cap and trade system for restricting greenhouse gas emissions. Under such system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission allowances corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this legislative initiative remains uncertain. In addition to the pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an Endangerment Finding under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has proposed regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities, and may issue final rules as early as 2011. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce, depending on the applicability to company operations and the refining, processing, and use of oil and gas.

Web Site Access to Reports

Our Web site address is *www.saratogaresources.net.* We make available, free of charge on or through our Web site, our annual report, Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and all amendments to these reports as soon as reasonably practicable after such material is electronically filed with, or furnished to, the United States Securities and Exchange Commission.

Item 1A.

Risk Factors

Our business activities and the value of our securities are subject to significant hazards and risks, including those described below. If any of such events should occur, our business, financial condition, liquidity and/or results of operations could be materially harmed, and holders and purchasers of our securities could lose part or all of their investments.

Financial Risks Affecting Our Business

We have been, and may continue to be, adversely affected by general economic conditions

The disruption experienced in U.S. and global credit markets during second half of 2008 and subsequent global economic downturn resulted in decreased demand for oil and natural gas, resulting in a sharp drop in energy prices, and affected the availability and cost of capital and, in turn, had a material adverse effect on our results of operations, financial condition and liquidity. From an operating standpoint, the crisis resulted in a steep decline in the price we received for oil and natural gas and reduced revenues and profitability. Our reduced profitability arising from the global economic disruption was a principal factor, along with the effects of hurricanes, in the alleged non-compliance with various financial covenants in our existing debt facilities and our 2009 filing for protection under the Chapter 11. While the U.S. and global economies have experienced a slow recovery from the deep recessionary conditions that prevailed in late 2008 and much of 2009 and commodity prices have recovered a portion of the decline experienced over that period, uncertainty that continues to exist with respect to the pace and sustainability of the economic recovery continues to be a risk to oil and natural gas operators and other businesses. Global economic growth drives demand for energy from all sources, including fossil fuels. Should the U.S. and global economies experience further weakness, demand for energy and accompanying commodity prices may decline and our financial position may deteriorate along with our ability to operate profitably and our ability to obtain financing to support operations and the cost and terms of same, is unclear.

We have incurred significant net losses since the acquisition of our principal properties and may incur additional significant net losses in the future.

We have not been profitable since our acquisition of the Harvest Companies in July 2008. We incurred net losses of $19.4 million and $27.0 million for the years ended December 31, 2010 and 2009, respectively. Since the Harvest Acquisition in 2008, our efforts to achieve profitability have focused on growing our production and reducing lease operating expenses. As a result of the steep decline in commodity prices accompanying the global recession beginning in late 2008, we suffered reductions in revenues and values of reserves and declines in profitability which, in turn, led to our inability to access our revolving credit facility and ultimate filing for protection under Chapter 11 of the U.S. Bankruptcy Code. While we successfully exited bankruptcy in May 2010 and commodity prices have strengthened significantly from late-2008 and earlier-2009 levels, our efforts to increase production through planned development operations was curtailed during our bankruptcy as a result of our inability to access our revolving credit facility and administrative burdens associated with operation in bankruptcy and, since exit from bankruptcy, our development operations continue to be conducted on a curtailed basis as a result of our inability to draw additional funds under our credit facility. The uncertainties described in this Item 1A Risk Factors and elsewhere in this Form 10-K may impede our ability to ultimately find, develop and exploit natural gas and oil reserves and attain profitability. Our failure to achieve profitability in the future could materially adversely affect our ability to fully implement and continue our exploration and development program, service our indebtedness and raise additional capital.

Our leverage and debt service obligations may adversely affect our cash flow and our ability to find and develop reserves.

At December 31, 2010, our indebtedness under our revolving credit facility and term loan totaled $131.2 million (includes unamortized discount of $4.1 million), all of which matures in April 2012.

Our leverage and the current and future restrictions contained in the agreements governing our indebtedness may reduce our ability to incur additional indebtedness, engage in certain transactions or capitalize on acquisition or other business opportunities. Our indebtedness and other financial obligations and restrictions could have important consequences. For example, they could:

impair our ability to obtain additional financing in the future for capital expenditures, potential acquisitions, general corporate purposes or other purposes;

have a material adverse effect if we fail to comply with financial and restrictive covenants in any of our debt agreements, including an event of default if such event is not cured or waived;

require us to dedicate a substantial portion of future cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general corporate requirements;

limit our flexibility in planning for, or reacting to, changes in our business and industry; and place us at a competitive disadvantage to those who have proportionately less debt.

Our credit facilities include certain financial covenants that require, among other things, that we satisfy certain interest coverage and asset to liability ratios, production levels and other financial performance metrics. If we breach a financial covenant and we are unable to cure such violation or obtain waivers from our lenders under our credit facilities within the applicable cure periods, such violation will constitute an event of default under the credit facilities, and our lenders could accelerate the due dates for the payments of all outstanding indebtedness and exercise their remedies as a secured creditor with respect to the collateral securing the credit facilities, which is substantially all of our natural gas and oil properties. In the event of any such events of default, and on or before the amounts owing under our credit facilities mature in April 2012, we expect that we will be required to seek alternative financing in order to retire amounts owing under our existing credit facilities. If we are unable to cure any such defaults or repay amounts owing under our credit facilities when they come due, either through operating cash flow or alternative financing, we may be required to liquidate some or all of our properties to satisfy our indebtedness.

Our credit facilities also include certain prohibitions on the incurrence of additional indebtedness without the consent of our lenders. Unless waived by our lenders, such prohibitions on the incurrence of additional indebtedness limit our development program to initiatives funded through operating cash flow. Such restrictions have resulted in curtailment of our development plans since early 2009 and continue to limit development of our properties.

We may not be able to generate sufficient cash flow to meet our debt service and other obligations due to events beyond our control.

Our ability to generate cash flow from operations and to make scheduled payments on our indebtedness will depend on our future financial performance. Our future performance will be affected by a range of economic, competitive, legislative, operating and other business factors, many of which we cannot control, such as general economic and financial conditions in our industry or the economy at large. Those factors, particularly the sharp decline in the global economy and the accompanying drop in oil and natural gas prices, resulted in certain alleged covenant defaults under our credit facilities and the eventual action on our part, during 2009, to seek protection under Chapter 11.

We remain subject to the same risks as led to our prior alleged covenant defaults and bankruptcy. A significant reduction in operating cash flow resulting from changes in economic conditions, increased competition, or other events could increase the need for additional or alternative sources of liquidity and could have a material adverse effect on our business, financial condition, results of operations and prospects and our ability to service our debt and other obligations. If we are unable to service our indebtedness, we will be forced to adopt an alternative strategy that may include actions such as reducing or delaying acquisitions and capital expenditures, selling assets, restructuring or further refinancing our indebtedness or seeking equity capital. We cannot assure you that any of these alternative strategies could be effected on satisfactory terms, if at all, or that they would yield sufficient funds to make required payments on our indebtedness. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

We expect to have substantial capital requirements, and we may be unable to obtain needed financing on satisfactory terms.

Pursuant to our business plan, we expect to make substantial capital expenditures for the acquisition, development, production, exploration and abandonment of oil and gas properties. Our capital requirements will depend on numerous factors, and we cannot accurately predict the timing and amount of our capital requirements. We presently finance our capital expenditures through cash flow from operations and cash on hand and, since early 2009, the lack of credit availability under our revolving credit facility has resulted in curtailment of our development program. In order to fully resume our development program at levels deemed optimal by management, or if our capital requirements vary materially from those reflected in our projections, we may require additional financing. A decrease in expected revenues or adverse change in market conditions could make obtaining this financing economically unattractive or impossible. Without additional capital resources, we will be forced to limit or defer our planned natural gas and oil exploration and development program to those activities that can be funded from our cash flow and cash on hand which may, in turn, adversely affect the recoverability and ultimate value of our natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations. Further, we may lack capital to complete potential acquisitions or to capitalize on other business opportunities.

If we are unable to effectively manage the commodity price risk of our production if energy prices fall, we may not realize the anticipated cash flows from our acquisitions.

If we fail to manage the commodity price risk of our production and energy prices fall, we may not be able to realize the cash flows from our assets that are currently anticipated even if we are successful in increasing the production and ultimate recovery of reserves. In early 2010, the administrative agent under our credit facilities unwound our existing hedges and, since that time, we have operated without hedges in place and bear the full risk of commodity price fluctuations. Under the terms of our amended credit facilities currently in place, without consent of our lender, we are limited to hedging not more than 60% of production. Compared to some other participants in the oil and gas industry, we are a relatively small company with modest resources. Therefore, there is the possibility that we may be required to either purchase relatively expensive put options, or commit to deliver future production, to manage the commodity price risk of our future production. To the extent that we commit to deliver future production, we may be forced to make cash deposits available to counterparties as they mark to market these financial hedges. This funding requirement may limit the level of commodity price risk management that we are prudently able to complete. In addition, we are unlikely to hedge undeveloped reserves to the same extent that we hedge the anticipated production from proved developed reserves.

If we place hedges on future production and encounter difficulties meeting that production, we may not realize the originally anticipated cash flows.

Our assets consist of a mix of reserves, with some being developed while others are undeveloped. To the extent that we sell the production of these reserves on a forward-looking basis but do not realize that anticipated level of production, our cash flow may be adversely affected if energy prices rise above the prices for the forward-looking sales. In this case, we would be required to make payments to the purchaser of the forward-looking sale equal to the difference between the current commodity price and that in the sales contract multiplied by the physical volume of the shortfall. There is the risk that production estimates could be inaccurate or that storms or other unanticipated problems could cause the production to be less than the amount anticipated, causing us to make payments to the purchasers pursuant to the terms of the hedging contracts.

Derivatives regulation included in recently adopted financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which contains comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as our company, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation contains significant derivatives regulation, including provisions requiring certain transactions to be cleared on exchanges and containing a requirement to post cash collateral (commonly referred to as margin) for such transactions as well as certain clearing and trade-execution requirements in connection with our derivative activities. The Act provides for a potential exception from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exception applies to particular derivative transactions and to the parties to those transactions. However, we do not know the definitions that the CFTC will actually promulgate nor how these definitions will apply to us. The financial reform legislation may also 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.

Depending on the rules and definitions adopted by the CFTC, we could be required to post collateral with our dealer counterparties for our commodities hedging transactions. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity, thereby reducing our ability to use cash for investment or other corporate purposes, or would require us to increase our level of debt), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation 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 legislation 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 legislation and regulations is to lower commodity prices. In addition, a requirement for our counterparties to post collateral would likely result in additional costs being passed on to us, thereby decreasing the effectiveness of our hedges and our profitability. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Oil and Gas Risks Affecting Our Business

Drilling for natural gas and oil is a speculative activity and involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

We engage in exploration and development drilling activities. Any such activities may be unsuccessful for many reasons. In addition to a failure to find oil or natural gas, drilling efforts can be affected by adverse weather conditions (such as hurricanes and tropical storms in the Gulf of Mexico), cost overruns, equipment shortages and mechanical difficulties. Therefore, the successful drilling of a gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, could cause a well to become uneconomic or only marginally economic. In addition to their costs, unsuccessful wells could impede our efforts to replace reserves.

Our business involves a variety of inherent operating risks, including:

fires;

explosions;

blow-outs and surface cratering;

uncontrollable flows of gas, oil and formation water;

natural disasters, such as hurricanes and other adverse weather conditions;

pipe, cement, subsea well or pipeline failures;

casing collapses;

mechanical difficulties, such as lost or stuck oil field drilling and service tools;

abnormally pressured formations; and

environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, platforms, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations. We could also incur substantial losses due to costs and/or liability incurred as a result of:

injury or loss of life;

severe damage to and destruction of property, natural resources and equipment;

pollution and other environmental damage;

clean-up responsibilities;

regulatory investigations and penalties;

suspension of our operations; and

repairs to resume operations.

Oil and natural gas prices are volatile and a decline in oil and natural gas prices would affect our financial results and impede growth.

Our future revenues, profitability and cash flow will depend substantially upon the prices and demand for oil and natural gas. The markets for these commodities are volatile and even relatively modest drops in prices can affect our financial results and impede our growth. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

domestic and foreign supplies of oil and natural gas;

price and quantity of foreign imports of oil and natural gas;

actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil and natural gas price and production controls;

level of consumer product demand;

level of global oil and natural gas exploration and productivity;

domestic and foreign governmental regulations;

level of global oil and natural gas inventories;

political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;

weather conditions;

technological advances affecting oil and natural gas consumption;

overall U.S. and global economic conditions; and

price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Lower oil and natural gas prices may not only decrease our expected future revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. This may result in us having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition and results of operations.

To attempt to reduce our price risk, we have periodically entered into hedging transactions with respect to a portion of our expected future production and may enter into such transactions in the future. We cannot assure you that such transactions will reduce the risk or minimize the effect of any decline in oil or natural gas prices or that counterparties to hedging transactions will be able to meet their requirements in those hedging transactions. Any substantial or extended decline in the prices of or demand for oil or natural gas would have a material adverse effect on our financial condition and results of operations.

Reserve estimates depend on many assumptions that may turn out to be inaccurate and any material inaccuracies in the reserve estimates or underlying assumptions of our properties will materially affect the quantities and present value of those reserves.

Estimating crude oil and natural gas reserves is complex and inherently imprecise. It requires interpretation of the available technical data and making many assumptions about future conditions, including price and other economic conditions. In preparing such estimates, projection of production rates, timing of development expenditures and available geological, geophysical, production and engineering data are analyzed. The extent, quality and reliability of this data can vary. This process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. If our interpretations or assumptions used in arriving at our reserve estimates prove to be inaccurate, the amount of oil and gas that will ultimately be recovered may differ materially from the estimated quantities and net present value of reserves owned by us. Any inaccuracies in these interpretations or assumptions could also materially affect the estimated quantities of reserves shown in the reserve reports summarized herein. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from estimates. 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.

Unless we replace crude oil and natural gas reserves our future reserves and production will decline.

Our future crude oil and natural gas production will depend on our success in finding or acquiring additional reserves. If we are unable to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both. Our ability to maintain or expand our asset base of oil and gas reserves has been curtailed since early 2009 as a result of our inability to access our revolving credit facility and the resulting requirement that we fund capital investments from cash flow and cash on hand. In the absence of additional external financing, our ability to make planned capital investments to maintain and expand our reserves would be impaired to the extent cash flow from operations is reduced due to natural declines in production, declines in commodity prices or otherwise. Even if we have sufficient financing to support our optimum development plan, we may not be successful in exploring for, developing or acquiring additional reserves.

Competition for oil and gas properties and prospects is intense and some of our competitors have larger financial, technical and personnel resources that could give them an advantage in evaluating and obtaining properties and prospects.

We operate in a highly competitive environment for reviewing prospects, acquiring properties, marketing oil and gas and securing trained personnel. Many of our competitors are major or independent oil and gas companies that possess and employ financial resources that allow them to obtain substantially greater technical and personnel resources than we. We actively compete with other companies when acquiring new leases or oil and gas properties. For example, new leases may be acquired through a sealed bid process and are generally awarded to the highest bidder. These additional resources can be particularly important in reviewing prospects and purchasing properties. Competitors may be able to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Competitors may also be able to pay more for productive oil and gas properties and exploratory prospects than we are able or willing to pay. If we are unable to compete successfully in these areas in the future, our future revenues and growth may be diminished or restricted.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute exploration and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third-party services to maximize the efficiency of our organization. The cost of oil field services typically fluctuates based on demand for those services. While we have historically had excellent relationships with oil field service companies, there is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our exploitation and exploration operations, which could have a material adverse effect on our business, financial condition or results of operations.

The geographic concentration of our properties subjects us to an increased risk of loss of revenue or curtailment of production from factors affecting the Louisiana Gulf Coast specifically.

The geographic concentration of our properties in the Louisiana Gulf Coast means that some or all of the properties could be affected should the region experience:

severe weather;

delays or decreases in production, the availability of equipment, facilities or services;

delays or decreases in the availability of capacity to transport, gather or process production; and/or

changes in the regulatory environment.

For example, the oil and gas properties that we acquired in July 2008 were damaged by Hurricanes Katrina, Rita, Gustav and Ike, which required the prior owners of the properties, in the case of Hurricanes Katrina and Rita, and us, in the case of Hurricanes Gustav and Ike, to spend a considerable amount of time and capital on inspections, repairs, debris removal, and the drilling of replacement wells. Although we maintain insurance coverage to cover a portion of these types of risks, there may be potential risks associated with our operations not covered by insurance. There also may be certain risks covered by insurance where the policy does not reimburse us for all of the costs related to a loss.

Because all or a number of the properties could experience any of the same conditions at the same time, these conditions could have a relatively greater impact on our results of operations than they might have on other producers who have properties over a wider geographic area.

Market conditions or transportation impediments may hinder access to oil and gas markets or delay production.

Market conditions, the unavailability of satisfactory oil and natural gas transportation or the remote location of our drilling operations may hinder our access to oil and natural gas markets or delay production. The availability of a ready market for oil and gas production depends on a number of factors, including the demand for and supply of oil and gas and the proximity of reserves to pipelines or trucking and terminal facilities. In offshore operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms that we own or operate or that are owned and operated by others and, where facilities are owned and operated by others, the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in wells or delay initial production for lack of a market or because of inadequacy or unavailability of pipeline or gathering system capacity. When that occurs, we will be unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and gas and realization of revenues.

We may be unable to successfully integrate the operations of the properties we acquire.

We acquired our principal properties in July 2008 and our business plan includes pursuit of additional acquisitions of oil and natural gas properties in the future. Integration of the operations of the properties we acquire with our existing business will be a complex, time-consuming and costly process. Failure to successfully integrate the acquired businesses and operations in a timely manner may have a material adverse effect on our business, financial condition, results of operations and cash flows. The difficulties of combining the acquired operations include, among other things:

operating a larger organization;

coordinating potentially geographically disparate organizations, systems and facilities;

integrating corporate, technological and administrative functions;

diverting management s attention from other business concerns;

an increase in our indebtedness; and

potential environmental or regulatory liabilities and title problems.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

In addition, we face the risk of identifying, competing for and pursuing other acquisitions, which takes time and expense and diverts management s attention from other activities.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we will review properties prior to acquisition in a manner consistent with industry practices, such reviews are not capable of identifying all potential conditions. Generally, it is not feasible to review in depth every individual property involved in each acquisition. We focus our review efforts on the higher-value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to fully assess their condition, any deficiencies, and development potential. Inspections may not be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

We may not be the operator on all of our future properties and therefore may not be in a position to control the timing of development efforts, the associated costs, or the rate of production of the reserves on such properties.

As we carry out our planned drilling program, we may not serve as operator of all planned wells. We currently operate substantially all of our properties. However, it is possible that we will not serve as operator of all of the properties we may acquire in the future. As a result, we may have limited ability to exercise influence over the operations of some non-operated properties or their associated costs. Dependence on the operator and other working interest owners for these projects, and limited ability to influence operations and associated costs could prevent the realization of targeted returns on capital in drilling or acquisition activities. The success and timing of development and exploitation activities on properties operated by others depend upon a number of factors that will be largely outside of our control, including:

the timing and amount of capital expenditures;

the availability of suitable drilling rigs, drilling equipment, support vessels, production and transportation infrastructure and qualified operating personnel;

the operator s expertise and financial resources;

approval of other participants in drilling wells;

selection of technology; and

the rate of production of the reserves.

Our insurance may not protect us against all business and operating risks.

We maintain insurance for some, but not all, of the potential risks and liabilities associated with our business. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance policies are economically unavailable or available only for reduced amounts of coverage. As a result, we procure other desirable insurance on commercially reasonable terms, if possible. Although we will maintain insurance at levels we believe is appropriate and consistent with industry practice, we will not be fully insured against all risks, including high-cost business interruption insurance and drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our financial condition and results of operations. The oil and natural gas industry suffered extensive damage from Hurricanes Ivan, Katrina and Rita. As a result, insurance costs for many operators in the Gulf Coast region have increased significantly from the costs that similarly situated participants in this industry have historically incurred and insurers are requiring higher retention levels and limit the amount of insurance proceeds that are available after a major wind storm in the event that damages are incurred. If storm activity in the future is as severe as it was in 2005, insurance underwriters may no longer insure assets in the Gulf Coast region against weather-related damage. If an accident or other event resulting in damage to our operations including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage occurs and is not fully covered by insurance or a recoverable indemnity from a customer, it could adversely affect our financial condition and results of operations. Moreover, we may not be able to maintain adequate insurance in the future at rates we consider reasonable or be able to obtain insurance against certain risks.

Our operations will be subject to environmental and other government laws and regulations that are costly and could potentially subject us to substantial liabilities.

Crude oil and natural gas exploration and production operations in the United States and in the Gulf Coast region are subject to extensive federal, state and local laws and regulations. Companies operating in coastal waters are subject to laws and regulations addressing, among others, land use and lease permit restrictions, bonding and other financial assurance related to drilling and production activities, spacing of wells, unitization and pooling of properties, environmental and safety matters, plugging and abandonment of wells and associated infrastructure after production has ceased, operational reporting and taxation. Failure to comply with such laws and regulations can subject us to governmental sanctions, such as fines and penalties, as well as potential liability for personal injuries and property and natural resources damages. We may be required to make significant expenditures to comply with the requirements of these laws and regulations, and future laws or regulations, or any adverse change in the interpretation of existing laws and regulations, could increase such compliance costs. Regulatory requirements and restrictions could also delay or curtail our operations and could have a significant impact on our financial condition or results of operations.

Our oil and gas operations are subject to stringent laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations:

require the acquisition of a permit before drilling commences;

restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;

limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

impose substantial liabilities for pollution resulting from operations.

Failure to comply with these laws and regulations may result in:

the imposition of administrative, civil and/or criminal penalties;

incurring investigatory or remedial obligations; and

the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Although we intend to be in compliance in all material respects with all applicable environmental laws and regulations, we cannot assure you that we will be able to comply with existing or new regulations. In addition, the risk of accidental spills, leakages or other circumstances could expose us to extensive liability.

We are unable to predict the effect of additional environmental laws and regulations that may be adopted in the future, including whether any such laws or regulations would materially adversely increase our cost of doing business or affect operations in any area.

Under certain environmental laws that impose strict, joint and several liability, we may be required to remediate our contaminated properties regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were or were not in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations. Moreover, new or modified environmental, health or safety laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. Therefore, the costs to comply with environmental, health or safety laws or regulations or the liabilities incurred in connection with them could significantly and adversely affect our business, financial condition or results of operations. In addition, many countries as well as several states and regions of the U.S. have agreed to regulate emissions of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning of natural gas and oil, are greenhouse gases. Regulation of greenhouse gases could adversely impact some of our operations and demand for some of our services or products in the future. See Business Regulatory Matters.

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

Hydraulic fracturing is a process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate natural gas and, to a lesser extent, oil production. This process is typically regulated by state oil and natural gas agencies and has not been subject to federal regulation. However, due to concerns that hydraulic fracturing may adversely affect drinking water supplies, the EPA has commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, and a committee of the U.S. House of Representatives has commenced its own investigation into hydraulic fracturing practices. Additionally, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to subject hydraulic fracturing processes to regulation under that Act and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. If enacted, such a provision could require hydraulic fracturing activities to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements and meet plugging and abandonment requirements.

In unrelated oil spill legislation being considered by the U.S. Senate in the aftermath of the April 2010 Macondo well release in the Gulf of Mexico, Senate Majority Leader Harry Reid has added a requirement that natural gas drillers disclose the chemicals they pump into the ground as part of the hydraulic fracturing process. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Adoption of legislation or of any implementing regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on our exploration and production activities, which could make it more difficult to perform hydraulic fracturing, resulting in reduced amounts of oil and natural gas being produced, as well as increase our costs of compliance and doing business.

The catastrophic explosion of the Deepwater Horizon rig in the Gulf of Mexico will likely result in new governmental regulations relating to drilling, exploration and production activities in U.S. coastal waters, which could adversely affect our operations.

In April 2010, the *Deepwater Horizon*, an offshore drilling rig located in the deepwater of the Gulf of Mexico, sank following a catastrophic explosion and fire, which significantly and adversely disrupted oil and gas exploration activities in the Gulf of Mexico. The duration of this disruption is currently unknown. The President appointed a commission to study the causes of the catastrophe for the purpose of recommending to the President what legislative or regulatory measures should be taken in order to minimize the possibility of a reoccurrence of a disastrous oil spill. Pending the completion of that report, the United States government imposed a suspension of all deepwater drilling and exploration activity in the Gulf of Mexico through November 30, 2010, which moratorium has since been lifted. Various bills are being considered by Congress which, if enacted, could either significantly increase the costs of conducting drilling and exploration activities in the Gulf of Mexico, particularly in deepwater, or substantially curtail Gulf of Mexico drilling and operation activity.

Our operations are focused in the shallow waters of the Gulf Coast region. We do not operate in the deepwater of the Gulf of Mexico. However, although our exploration activity in the shallow waters was not disrupted by the *Deepwater Horizon* incident, enhanced scrutiny of operations in shallow waters has resulted and new safety and permitting requirements are under consideration.

There are a number of uncertainties affecting the oil and gas industry in the aftermath of the *Deepwater Horizon* events, including the possible increase or elimination of the current $75 million cap for non-reclamation liabilities under the Oil Pollution Act of 1990, the continued availability and affordability of insurance for drilling and exploration activities, the overall legislative and regulatory response to the catastrophe, and the ability to obtain drilling permits in the shallow water on a timely basis. Although the eventual outcome of these developments is currently unknown, additional regulatory and operational costs could have an adverse effect on our financial position and results of operations.

We depend on key personnel, the loss of any of whom could materially adversely affect future operations.

Our success will depend to a large extent upon the efforts and abilities of our executive officers and key operations personnel. The loss of the services of one or more of these key employees could have a material adverse effect on us. Our business will also be dependent upon our ability to attract and retain qualified personnel. Acquiring and keeping these personnel could prove more difficult or cost substantially more than estimated. This could cause us to incur greater costs, or prevent us from pursuing our exploitation strategy as quickly as we would otherwise wish to do.

Unanticipated decommissioning costs could materially adversely affect our future financial position and results of operations.

We may become responsible for unanticipated costs associated with abandoning and reclaiming wells, facilities and pipelines. Abandonment and reclamation of facilities and the costs associated therewith is often referred to as decommissioning. Should decommissioning be required that is not presently anticipated or the decommissioning be accelerated, such costs may exceed the value of reserves remaining at any particular time. We may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could have a material adverse effect on our financial position and results of operations.

If we are unable to acquire or renew permits and approvals required for operations, we may be forced to suspend or cease operations altogether.

The construction and operation of energy projects require numerous permits and approvals from governmental agencies. We may not be able to obtain all necessary permits and approvals, and as a result our operations may be adversely affected. In addition, obtaining all necessary permits and approvals may necessitate substantial expenditures and may create a risk of expensive delays or loss of value if a project is unable to function as planned due to changing requirements or local opposition.

Item 1B.

Unresolved Staff Comments

Not applicable

Item 2.

Properties

A description of our properties is included in Item 1. Business.

Item 3.

Legal Proceedings

In December 2009, the Parish of Plaquemines, State of Louisiana, filed additional assessments against multiple oil and gas companies, including Saratoga, for allegedly underpaid ad valorem taxes. The amount alleged to be due by Saratoga for the years 2009 and 2010 is $1.3 million. We are presently contesting the additional tax assessments in an action styled Aviva America, Inc., The Harvest Group, LLC, Harvest Oil & Gas, LLC, Saratoga Resources, Inc., Lobo Operating, Inc. and Lobo Resources, Inc. v. Robert R. Gravolet, In His Capacity as Assessor for Plaquemines Parish, Louisiana in the 25th Judicial District Court of Louisiana and, as to certain issues relating to such claim, in an administrative proceeding before the Louisiana Tax Commission. We believe the additional assessment is in error and intend to vigorously defend this action.

In February 2010, Saratoga filed a complaint in the United States Bankruptcy Court for the Western District of Louisiana against Barry Ray Salsbury, Brian Carl Albrecht, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer, each being former owners of The Harvest Group, LLC and/or Harvest Oil & Gas, LLC. The complaint alleges breach of the Purchase and Sale Agreements with the former owners arising from the underpayment of royalties to the State of Louisiana for periods prior to Saratoga s acquisition of the Harvest companies. Specifically, the complaint alleges that the underpayment of such royalties constituted a breach, by the former owners, of the representations and warranties that all royalty payments of the Harvest companies had been paid in full as of the closing of Saratoga s purchase of the Harvest companies. Saratoga is seeking monetary damages of approximately $1.4 million and a declaratory judgment against the former owners. Saratoga subsequently amended its complaint to add to the breach of contract claims additional claims based on fraud arising from the willful and knowing concealment of the underpayment of royalties.

In October 2010, Saratoga filed a separate complaint in the United States Bankruptcy Court for the Western District of Louisiana against Henry Calongne and Professional Oil & Gas Marketing, based on substantially identical facts as alleged in the complaint against the former owners of the Harvest companies. Mr. Calongne and Professional Oil & Gas Marketing served as the agent of the Harvest companies in computing the applicable royalty payments. Saratoga has asserted that Mr. Calongne and Professional Oil & Gas Marketing either negligently or knowingly colluded with the former owners with respect to the underpayment of royalties to the State of Louisiana. Saratoga is seeking monetary damages of approximately $1.4 million from Mr. Calongne and Professional Oil & Gas Marketing. Saratoga s action against the former owners and against Mr. Calongne and Professional Oil & Gas Marketing have been consolidated into a single cause of action.

We may from time to time be a party to lawsuits incidental to our business. As of December 31, 2010, we were not aware of any current, pending, or threatened litigation or proceedings that could have a material adverse effect on our results of operations, cash flows or financial condition.

Item 4.

(Removed and Reserved)

PART II

Item 5.

Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is traded on the OTCQB marketplace under the symbol SROE.PK. The following table sets forth the range of high and low sale prices of our common stock for each quarter during the past two fiscal years.

		High	Low
Calendar Year 2010	Fourth Quarter	$ 2.50	$ 1.25
	Third Quarter	2.23	1.15
	Second Quarter	3.24	1.06
	First Quarter	3.10	0.60
Calendar Year 2009	Fourth Quarter	$ 3.75	$ 0.51
	Third Quarter	2.01	0.21
	Second Quarter	0.60	0.10
	First Quarter	2.25	0.30

At March 8, 2011, the closing price of our common stock on the OTCQB marketplace was $3.05.

As of March 8, 2011, there were approximately 1,528 record holders of our common stock.

We have not declared or paid any dividends on our common stock since our inception, and we do not anticipate declaring or paying any dividends on our common stock for the foreseeable future. We currently intend to retain any future earnings to finance future growth. Any future determination to pay dividends will be at the discretion of our board of directors and will depend on our financial condition, results of operations, capital requirements and other factors the board of directors considers relevant. Pursuant to our Plan of Reorganization, no dividends or distributions may be made with respect to our equity holdings unless and until the holders of all allowed claims have been paid in full in cash in accordance with the plan. In addition, our ability to declare and pay dividends is restricted by our governing statute, as well as the terms of our existing credit facilities.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2010 with respect to the shares of our common stock that may be issued under our existing equity compensation plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities effected in column (a))
Equity compensation plans approved by security holders [1]			3,000,000
Equity compensation plans not approved by security holders [2]	1,017,500[3]	2.24	1,430,000
Total	1,017,500	2.24	4,430,000

(1)

Consists of 3,000,000 shares reserved for issuance under the Saratoga Resources, Inc. 2008 Long-Term Incentive Plan (the 2008 Plan)

(2)

Consists of 1,430,000 shares reserved for issuance under the Saratoga Resources, Inc. 2006 Employee and Consultant Stock Plan (the 2006 Plan) and non-plan stand alone stock option grants.

(3)

Consists of non-plan stand alone stock option grants to directors, employees and consultants. The options are exercisable on terms generally described in Note 11. Common Stock Stock-Based Compensation to our financial statements included herein.

2006 Employee and Consultant Stock Plan. The 2006 Employee and Consultant Stock Plan was adopted by our board of directors in January 2006 as an equity-based plan to provide incentives to, and to attract, motivate and retain employees and consultants.

The 2006 Plan is administered by the Compensation Committee of our board of directors and enables the committee to make stock grants. We initially reserved 1,200,000 shares of common stock for issuance under the 2006 Plan. In October 2007, the 2006 Plan was amended to increase the shares reserved thereunder to 2,525,000.

2008 Long-Term Incentive Plan. The 2008 Long-term Incentive Plan was adopted by our board of directors in October 2008 as an equity-based compensation plan to provide incentives to, and to attract, motivate and retain the highest qualified employees, non-employee directors and other third-party service providers. The 2008 Plan enables our Board of Directors to provide equity-based incentives through awards of options, stock appreciation rights, restricted stock, restricted stock units and other stock or performance-based awards.

Under the 2008 Plan, awards may be granted from time to time to eligible persons, consisting generally of officers, directors, employees and consultants, all generally in the discretion of the Compensation Committee of the board of directors, which is responsible for administering the 2008 Plan. We have initially reserved 3,000,000 shares of common stock for issuance under the 2008 Plan, subject to adjustment to protect against dilution in the event of certain changes in our capitalization. Shareholders holding greater than 50% of our common stock approved the 2008 Plan by written consent. We have not made any grants as yet under the 2008 Plan and do not intend to make any grants under that plan unless and until we distribute an Information Statement relating to the approval of that plan or resubmit the plan for approval at a shareholders meeting.

Item 6.

Selected Financial Data

Not applicable.

Item 7.

Management s Discussion and Analysis of Financial Condition and Results of Operations

General

Saratoga Resources, Inc. is an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of natural gas and crude oil properties. Our principal properties were acquired in July 2008 and are located in the transitional coastline and protected in-bay environment on parish and state leases of south Louisiana. See Harvest Acquisitions below. Prior to the July 2008 acquisition of our Louisiana properties, our operations were focused on production, development, acquisition and exploitation of various mineral interests in the State of Texas.

We operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code from March 31, 2009 until our exit from bankruptcy on May 14, 2010. See Chapter 11 Reorganization and 2010 Developments below.

At December 31, 2010, our principal properties covered approximately 33,869 gross acres (31,125 net), substantially all of which were held by production without near-term lease expirations, across 12 fields in the transitional coastline and protected in-bay environment on parish and state leases in south Louisiana. We own working interests in our properties ranging from 25% to 100%, with our average working interest on a net acreage leasehold basis being approximately 92%. Our net revenue interests in our properties range from 19% to 88%, with our average net revenue interest on a net acreage leasehold basis being approximately 72%. We operate over 90% of the wells that comprise our PV-10, enabling us to effectively exercise management control of our operating costs, capital expenditures and the timing and method of development of our properties. Following the Harvest Acquisitions and prior to the market disruption that occurred during the fourth quarter of 2008, we began an active development program to exploit these opportunities. Our development program was substantially curtailed during 2009 and much of 2010 as a result of the economic climate, lack of access to borrowing capacity under our revolving credit facility and our Chapter 11 filing. Most of our properties offer multiple stacked reservoir objectives with substantial behind pipe potential. We have identified multiple prospects on our acreage and, following our exit from bankruptcy, resumed our development program with the timing and level of development activities being limited by our ability to fund the same through cash on hand and operating cash flow. Subject to the availability of capital from outside sources, we intend to increase the level and accelerate the pace of our development activities. We believe execution of our development program will enable us to significantly grow our reserves, production and cash flow. There is no assurance, however, that we will be able to fund all of our planned development activities from cash on hand and operating cash flow or that such development activities will produce the expected increases in reserves, production and cash flow and there is no assurance that outside capital can be secured on acceptable terms, or at all, to fund accelerated development activities and increased levels of such activities.

As of December 31, 2010, based on reserve estimates prepared by independent petroleum engineers, we had 18.0 MMBoe of proved reserves, of which 44% was oil and 19% were proved developed. The PV-l0 of these proved reserves as of that date were $316 million before income taxes, or $236 million after future income taxes. Additionally, at December 31, 2010, we had probable reserves of 10.5 MMBoe, consisting of 38.0 Bcf of natural gas and 4.2 MMBls of oil, and possible reserves of 30.1 MMBoe, consisting of 101.7 Bcf of natural gas and 13.1 MMBls of oil. As of December 31, 2010, we had 54 proved behind pipe and shut-in development opportunities in 8 fields, 92 proved undeveloped opportunities within 37 proposed wells in 5 fields, 51 probable behind pipe and shut-in development opportunities, 33 probable undeveloped opportunities, 13 possible behind pipe and shut-in development opportunities and 21 possible undeveloped opportunities.

Harvest Acquisitions

In July 2008, we acquired all of the membership interest in Harvest Oil & Gas, LLC (Harvest Oil) and The Harvest Group, LLC (Harvest Group and, together with Harvest Oil, the Harvest Companies or the Predecessor Companies).

As consideration for the membership interests in the Harvest Companies, we paid to the former members of the Harvest Companies a combined purchase price of $105.7 million in cash and issued 4.9 million shares of our common stock. The cash portion of the purchase price included $33.7 million and $30.0 million paid by the Harvest Companies to pay a note payable to Macquarie Bank Limited (Macquarie) and to obtain a release of a net profits interest and an overriding royalty interest in the properties of the Harvest Companies held by Macquarie and its affiliates, respectively, which amounts we paid directly to Macquarie on behalf of the Harvest Companies at closing.

Of the 4.9 million shares of common stock issued in the acquisitions, 3.3 million shares were issued directly to Macquarie Americas Corp., an affiliate of Macquarie, pursuant to an agreement between Macquarie and the members of the Harvest Companies relating to the release of the net profits interest and overriding royalty interest held by Macquarie.

In conjunction with the Harvest Acquisition, and to finance the acquisition and post-acquisition operations, in July 2008, we entered into a Credit Agreement (the 2008 Wayzata Credit Agreement) with Wayzata Investment Partners, LLC (Wayzata) and a separate Credit Agreement (the 2008 Revolving Credit Agreement) with Macquarie. We borrowed $97.5 million under the 2008 Wayzata Credit Agreement and approximately $12.5 million under the 2008 Revolving Credit Agreement to pay the purchase price of the Harvest Acquisition and associated costs.

The Harvest Companies were independent oil and natural gas companies engaged in the production, development, and exploitation of natural gas and crude oil properties, together covering an estimated 33,000 gross acres (30,000 net) across 11 fields in the transitional coastline and protected in-bay environment on parish and state leases of south Louisiana.

We retained key members of the management and operational teams of the Harvest Companies and, following the Harvest Acquisition, shifted the focus of our operations to the continued development and operations of the various holdings of the Harvest Companies.

Chapter 11 Reorganization

Beginning late in the third quarter of 2008, accelerating during the fourth quarter of 2008, and continuing into the first quarter of 2009, our operations were materially adversely affected by a sharp drop in the projected demand for, and price of, oil and natural gas that accompanied the severe disruptions in credit and financial markets that resulted in economic contraction in the U.S. and globally. While we entered into hedging transactions to reduce our exposure to commodity price risks, we were still subject to risks associated with declines in the price of oil and natural gas relating to unhedged production.

On July 14, 2008, the day of closing for the Harvest Acquisitions, crude oil prices closed at $145.66 per barrel, while the spot price for natural gas averaged $11.45 per MCF. Oil had remained above $100 per barrel for sixteen consecutive weeks at that time. Equivalent oil and natural gas prices in March 2009 were 63% and 65% respectively lower than they were when we closed the Harvest Acquisitions and entered into the credit agreements with Wayzata and Macquarie.

On February 26, 2009, Wayzata issued a notice of default wherein it alleged nine non-monetary breaches of the 2008 Wayzata Credit Agreement, or events of default. Wayzata, in its notice of default, did not exercise any of its rights under the 2008 Wayzata Credit Agreement, but expressly reserved the right to do so. We disputed Wayzata s notice of default as premature and based on incomplete data and failure to take into account various developments and circumstances.

Macquarie also issued notice of default dated February 26, 2009, which was expressly based on Wayzata s Notice of Default. The Macquarie notice of default was triggered by cross default provisions in the 2008 Revolving Credit Agreement defining an event of default as an event or condition occurring which permits the holder of any material debt to accelerate that obligation. Macquarie stated in its notice of default that it was not initiating any action to exercise its rights and remedies available, though its right to do so was expressly reserved. As a result of the Macquarie notice of default, Macquarie rejected our requests to access additional credit available under the 2008 Revolving Credit Agreement, which restriction of credit impaired our ability to continue our development program. We disputed the Macquarie notice of default.

Following the receipt of the referenced notices of default from Wayzata and Macquarie, we entered into discussions with Wayzata seeking an amicable resolution and forbearance in order to cure the alleged covenant defaults and to access available credit under our 2008 Revolving Credit Agreement to continue pursuit of our ongoing drilling, workover and recompletion program. Despite management s efforts, management and our board of directors determined that a bankruptcy court reorganization would offer the best means of addressing our existing debt structure and realization of the long-term anticipated benefits of our drilling, workover and recompletion program. To that end, on March 31, 2009 (the Petition Date), we, and our principal operating subsidiaries, filed voluntary Chapter 11 petitions in the U.S. Bankruptcy Court for the Western District of Louisiana.

As a result of the Chapter 11 filing, we continued to operate our business and manage our properties as debtors-in-possession, although our development activities were substantially curtailed due to limited access to financing, and engaged in negotiations and other efforts to resolve issues with our lenders, in particular we sought to restructure the 2008 Wayzata Credit Agreement. On April 19, 2010, the Bankruptcy Court entered an order confirming our Modified Third Amended Plan of Reorganization (the Plan). The Plan became effective and we exited bankruptcy on May 14, 2010 (the Effective Date), following amendment of our existing debt facilities.

Under the Plan (1) the 2008 Revolving Credit Agreement was amended (the Amended Revolving Credit Agreement) as to maturity date and interest rate and claims under the revolving credit agreement were allowed in the amount of $23.5 million (including outstanding letters of credit), of which $5.5 million was paid on exit from bankruptcy; (2) the 2008 Wayzata Credit Agreement was amended and restated (the Amended and Restated Term Credit Agreement) as to maturity and interest rate and claims under the term credit agreement were allowed in the amount of $127.5 million; (3) our other creditors were paid, or will be paid, substantially in whole; (4) amounts owing on notes payable to officers will be payable in full, including compound accrued interest, in forty months; (5) a warrant to purchase 2,000,000 shares of our common stock was issued to the administrative agent for the revolving and term credit facilities; the warrant will be exercisable at $0.01 per share and will vest 111,111 shares on exit from bankruptcy and 111,111 shares per month thereafter; and (6) 483,310 shares of common stock were issued pro rata among the oil lien claim creditors, other secured creditors and unsecured creditors; all as more fully described under 2010 Developments.

2010 Developments

Exit from Bankruptcy

As noted above, on May 14, 2010, our Plan became effective and we exited bankruptcy. In connection with our exit from bankruptcy, we restructured certain financial obligations as described more fully below. We recorded $2.2 million and $5.7 million of reorganization expenses in 2010 and 2009, respectively.

Amended Revolving Credit Agreement

On May 14, 2010, we entered into an Amended Revolving Credit Agreement reflecting the terms described in the Plan. Under the Amended Revolving Credit Agreement, our revolving credit facility was revised to provide for total outstanding principal under the facility of $18.0 million, including $10.2 million in letters of credit and after payment of $5.5 million. No further borrowings can be made under the Amended Revolving Credit Agreement.

The Amended Revolving Credit Agreement provides for payments of interest only on a monthly basis at a floating rate of prime plus 2% with all amounts owing under the agreement being due and payable in full on April 30, 2012.

Amended and Restated Term Credit Agreement

On May 14, 2010, we entered into an Amended and Restated Term Credit Agreement reflecting the terms described in the Plan. Under the Amended and Restated Term Credit Agreement, our term credit facility was revised to reflect the total amount borrowed and owing thereunder of $127.5 million, including $30 million of accrued and unpaid interest expense and reorganization costs, and to provide for accrual of interest at 11.25% per annum payable interest only on a monthly basis with all amounts owing under the agreement being due and payable in full on April 30, 2012. As a result of the amendment of the 2008 Wayzata Credit Agreement to reflect the amended terms set out in the Amended and Restated Term Credit Agreement, our effective interest rate on funds owing under such facility was reduced from 22% to 13%. The stated interest rate was reduced from 20% to 11.25%.

Wayzata Warrant and Creditor Shares

On or shortly after May 14, 2010, pursuant to the Plan, we issued (1) a warrant in favor of Wayzata to purchase up to 2,000,000 shares of our common stock exercisable at $0.01 per share, which warrant vests and is exercisable 111,111 shares on the Effective Date and 111,111 shares per month over the following seventeen months unless all amounts payable under the Amended and Restated Term Credit Agreement are paid in full, in which case any unvested portion of the warrant on the date of repayment in full will be forfeited, and (2) 483,310 shares of common stock pro rata among oil lien claim creditors, other secured creditors and unsecured creditors. The warrant issued to Wayzata was recorded during 2010 as a debt discount to long-term debt on the balance sheet in the amount of $3.7 million, the value of the warrant as determined based on the Black-Scholes model. The debt discount attributable to the warrant is being amortized as additional interest expense using the effective interest rate method through April 2012 and resulted in additional interest expense of $1.7 million during 2010. The shares issued to creditors were recorded during 2010 as a loss on settlement of accounts payable on the Statement of Operations in the amount of $1.0 million, being the fair value of the common stock issued.

Mineral Royalty Audit Payable

In October 2009, the Louisiana Department of Mineral Resources notified us of the completion of audits of royalty payments from Harvest Oil and Harvest Group for the period from September 2005 to March 2009. Pursuant to the notifications, the Department of Mineral Resources asserted deficiencies in royalty payments totaling $1.4 million. Additionally, the Department of Mineral Resources estimated interest and penalties owing of approximately $0.8 million.

Mineral royalties owing pursuant to the audit conducted by the Louisiana Department of Mineral Resources, totaling $2.0 million, were allowed under the Plan and are payable in twenty four monthly installments of $71,235.

The full amount of the asserted deficiency in royalty payments was included in lease operating expense for 2009 and the estimated interest and penalties were included in interest expense. At December 31, 2010, $1.3 million (includes $0.4 million in penalties) remained due and owing with respect to the mineral royalty deficiency and was reflected as a liability on our balance sheet.

At December 31, 2010, we were pursuing an action against the former owners of the Harvest Companies and a third party responsible for computing royalties in order to seek reimbursement of underpaid mineral royalties for periods prior to the Harvest Acquisition.

Other Secured Creditors and Unsecured Creditors

With respect to substantially all other secured and unsecured creditors (other than management notes), under the Plan, all allowed claims of unsecured creditors and oil lien claim creditors will be paid in full of which unsecured creditors received 75% in cash on exit from bankruptcy and the balance is payable in quarterly installments over one year and oil lien claim creditors received 80% in cash on exit from bankruptcy and the balance is payable in quarterly installments over one year. At December 31, 2010, $1.6 million (includes $0.3 million in accrued interest) owing to unsecured creditors and oil lien claim creditors remained due and owing and was reflected on our balance sheet.

Management Notes

With respect to claims (the Management Claims) by Thomas F. Cooke and Andrew C. Clifford, members of management of our company, pursuant to existing promissory notes from Saratoga, from and after the Effective Date of the Plan, the Management Claims will be payable in full, including compound accrued interest, in forty months.

Equity Holders

Subject to the issuance of the warrant to Wayzata and the issuance of shares to certain creditors under the Plan, as described herein, each holder of our equity securities, including common stock, warrants and options, retained identical interests in our company following the Effective Date, provided, however, that holders of equity securities will receive no dividends or distributions in respect of their equity holdings unless and until the holders of all allowed claims have been paid in full in cash in accordance with the Plan.

Drilling and Development Activities

During 2010, we continued our plan to further develop our assets albeit at a curtailed pace. Prior to our exit from bankruptcy, our principal development activities related to the ongoing full field study in the Grand Bay field and planning for post-bankruptcy development activities, including infrastructure upgrades and drilling plans. Following our exit from bankruptcy, we resumed development activities at a pace supported by our operating cash flow and cash on hand. During 2010, our drilling and development activities were focused on bringing shut-in production and curtailed production back on line, or to capacity, through deferred maintenance projects, recompletions and workovers. We have identified deferred maintenance and third party facilities capacity limitations across eleven fields that have resulted in wells in each of those fields being shut-in or produced at below capacity. Since our exit from bankruptcy, we have commenced a program to bring current deferred maintenance and equipment upgrades, and are working with third party facilities operators to upgrade or restart facilities, in order to restore or increase production from wells currently shut-in or produced at below capacity. Planned operations in that regard are ongoing and scheduled to run through mid-2011.

During 2010, we conducted 57 recompletions and/or workovers and invested $9.9 million in our development program, including our deferred maintenance projects. No drilling, recompletions or workovers were ongoing at December 31, 2010.

At December 31, 2010, we had approximately 111 gross (98 net) wells in production.

Seismic Activities

During 2010, we purchased a license for 3D seismic covering 42.88 blocks (330 square miles) in Breton Sound. Pursuant to the license agreement we paid an initial installment in May 2010 of $185,000 and, beginning June 1, 2010, make monthly installments of $80,000 for ten months ending March 2011.

Breton Sound Lease Acquisition

During 2010, we paid $143,276 for three Louisiana State Leases covering a total area of 535.61 acres. The leases are located in Breton Sound Blocks 18, 19, 50 and 51, close to our existing facilities and pipeline infrastructure and within the blocks covered by our 3D seismic license. We hold a 100% working interest in these three year leases, which all carry a 22% royalty burden to the state of Louisiana.

Disposition of Adcock Farms

During 2010, we sold our fifty percent (50%) participation interest, representing our entire interest, in the Adcock Farms lease and well in Dawson County, Texas. The sales price for the interest was $95,000. The $95,000 sales price of the Adcock Farms lease and well was recorded as other income as a gain on the sale. There were no reserves in our reserve report associated with this lease.

Executive Compensation

On May 14, 2010, the Effective Date of our exit from bankruptcy, we paid one-time bonuses of $55,000 to our Chief Executive Officer and to our President and increased the base salary of each to $305,000.

Consulting Agreements and Fees

During 2010, we retained the services of a non-affiliate consulting geophysicist to assist in advanced geophysics applications relating to our exploration development program and retained the services of a non-affiliate finance and business development consultant to assist in strategic, industry partnering and financial market planning in order to accelerate our development activities. Pursuant to those consulting arrangements, we granted certain stock options and are paying monthly cash consulting fees.

Stock Option Activity

During 2010, our board of directors approved stock option grants, effective on exit from bankruptcy, to purchase an aggregate of 845,000 shares of common stock to our directors and to various key employees, including an aggregate of 50,000 stock options granted to directors and 150,000 stock options granted to an officer. The options are exercisable at $3.00 per share for a term of ten years. The options are subject to different vesting periods. 330,000 of the stock options were forfeited during 2010.

In July 2010, we granted stock options to purchase 115,000 shares of common stock to employees, including 40,000 options granted to an officer. The options are exercisable at $1.53 per share for a term of ten years and vest ratably over three years.

In July 2010, we granted stock options to purchase 120,000 shares of common stock to employees, including 100,000 options granted to an officer. The options are exercisable at $1.71 per share for a term of ten years and vest ratably over three years. 20,000 of the stock options were forfeited during 2010.

In July 2010, we granted stock options to purchase 202,500 shares of common stock to consultants. The options are exercisable at $1.71 per share for a term of five years. 2,500 of the options were granted to a consultant for investor relations and vested on the date of grant. 200,000 of the stock options were granted to a consultant for business development services of which 10,000 vested on grant date. The remaining 190,000 options vest as follows: (i) 2,000 options vest each month from August 2010 to December 2010; (ii) 80,000 options vest based on satisfaction of certain performance criteria, and (iii) 25,000 options vest on each of June 30, 2011, December 31, 2011, December 31, 2012 and December 31, 2013 provided that the consultant continues to provide services to the Company as of those dates.

In August 2010, we granted stock options to purchase 10,000 shares of common stock to a consultant. The options are exercisable at $1.39 per share for a term of five years and vest in full on February 28, 2011.

Warrant

In April 2010, we sold to a service provider, for a purchase price of $100, a warrant to purchase 40,000 shares of common stock. The warrant is exercisable at $3.00 per share for a term of five years.

Production Handling Fees

During 2010, we discovered an error in third party billings for production handling services we provided between 2006 and 2009. In October 2010, we received a one-time payment of $1.1 million in full satisfaction of underbilled production handling services.

The underbillings resulted in an understatement of our revenue in 2006, 2007, 2008 and 2009. We assessed the materiality of this error on our financial statements for the years ended December 31, 2006, 2007, 2008 and 2009 in accordance with SEC Staff Accounting Bulletin (SAB) No. 99, Materiality and SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108, using both the roll-over method and iron-curtain method as defined in SAB 108. We concluded that the effect of this error was not material to our financial statements for any prior period and, as such, those financial statements are not materially misstated. However, the error was deemed to be material to the current period, and as a result, the prior year financial statements presented in this Form 10-K were corrected to pursuant to SAB NO. 108.

Elimination of Hedges

In February 2010, the administrative agent under our credit facilities liquidated all of our existing hedge contracts and applied the proceeds thereof to amounts owed under the facilities. As a result, our production is currently unhedged. Under the terms of our amended credit facilities, we are permitted to enter into hedges provided that no more than 60% of our production may be hedged without the consent of the administrative agent under those facilities.

Critical Accounting Policies

We prepare our consolidated and combined financial statements in this report using accounting principles that are generally accepted in the United States (GAAP). GAAP represents a comprehensive set of accounting and disclosure rules and requirements. We must make judgments, estimates, and in certain circumstances, choices between acceptable GAAP alternatives as we apply these rules and requirements. The most critical estimate we make is the engineering estimate of proved oil and gas reserves. This estimate affects the application of the successful efforts method of accounting, the calculation of depreciation, depletion, and amortization of oil and gas properties and the estimate of the impairment of our oil and gas properties. It also affects the estimated lives used to determine asset retirement obligations. In addition, the estimates of proved oil and gas reserves are the basis for the related standardized measure of discounted future net cash flows.

Estimated Oil and Gas Reserves

The evaluation of our oil and gas reserves is critical to management of our operations and ultimately our economic success. Decisions such as whether development of a property should proceed and what technical methods are available for development are based on an evaluation of reserves. These oil and gas reserve quantities are also used as the basis of calculating the unit-of-production rates for depreciation, evaluating impairment and estimating the life of our producing oil and gas properties in our asset retirement obligations. Our proved reserves are classified as either proved developed or proved undeveloped. Proved developed reserves are those reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves include reserves expected to be recovered from new wells from undrilled proven reservoirs or from existing wells where a significant major expenditure is required for completion and production. We also report probable reserves and possible reserves, each of which reflects a lower degree of certainty of realization than proved reserves.

Independent reserve engineers prepare the estimates of our oil and gas reserves presented in this report based on guidelines promulgated under GAAP and in accordance with the rules and regulations of the Securities and Exchange Commission. The evaluation of our reserves by the independent reserve engineers involves their rigorous examination of our technical evaluation and extrapolations of well information such as flow rates and reservoir pressure declines as well as other technical information and measurements. Reservoir engineers interpret these data to determine the nature of the reservoir and ultimately the quantity of proved, probable and possible oil and gas reserves attributable to a specific property. Our proved reserves in this report include only quantities that we expect to recover commercially using current prices, costs, existing regulatory practices and technology. While we are reasonably certain that the proved reserves will be produced, the timing and ultimate recovery can be effected by a number of factors including completion of development projects, reservoir performance, regulatory approvals and changes in projections of long-term oil and gas prices. Revisions can include upward or downward changes in the previously estimated volumes of proved reserves for existing fields due to evaluation of (1) already available geologic, reservoir, or production data or (2) new geologic or reservoir data obtained from wells. Revisions can also include changes associated with significant changes in development strategy, oil and gas prices, or production equipment/facility capacity.

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows relies on these estimates of oil and gas reserves using commodity prices and costs. Effective for the year ending December 31, 2009 and later, commodity prices are based on the average prices as measured on the first day of each of the last twelve calendar months. In our 2010 year-end reserve report, we used an average oil price of $78.79 per Bbl, and a natural gas price of $5.11 per Mcf which includes adjustments by property for energy content, quality, transportation fees, and regional price differentials. While we believe that future operating costs can be reasonably estimated, future prices are difficult to estimate since the market prices are influenced by events beyond our control. Future global economic and political events will most likely result in significant fluctuations in future oil and gas prices. Application of the new reserve rules resulted in the use of lower prices at December 31, 2010 for both oil and gas than would have resulted under the previous rules.

Revenue Recognition

We recognize oil and gas revenue from interests in producing wells as the oil and gas is sold. Revenue from the purchase, transportation, and sale of natural gas is recognized upon completion of the sale and when transported volumes are delivered. We recognize revenue related to gas balancing agreements based on the entitlement method. Our net imbalance position at December 31, 2010 was immaterial.

Derivative Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance which requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we utilize are to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price risk management activities as accounting hedges under the accounting guidance and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings.

Oil and Gas Operations

Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for the classification of reserves as proved, the associated leasehold costs are reclassified to proved properties.

Oil and gas exploration costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or suspended, on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while we seek government or co-venture approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

Oil and gas development costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Assets are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and crude oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and do not have a future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable and estimable.

Debt Modification

Under the Amended and Restated Term Credit Agreement, our term credit facility was revised to reflect the total amount borrowed and owing thereunder of $127.5 million and to provide for accrual of interest at 11.25% per annum payable interest only on a monthly basis with all amounts owing under the agreement being due and payable in full on April 30, 2012. The principal amount owing under the term note includes interest expense and certain reorganization costs totaling $30.0 million that were capitalized as part of the aggregate principal amount payable on the term loan.

In evaluating the accounting for the debt restructuring under the Plan, we were required to make a determination as to whether the debt restructuring should be accounted for as a Troubled Debt Restructuring (TDR) or as an extinguishment or modification of debt. The relevant accounting guidance required us to determine first whether the exchanges of debt instruments should be accounted for as a TDR. A TDR results when it is determined that a debtor is experiencing financial difficulties and the creditors grant a concession; otherwise, such exchanges should be accounted for as an extinguishment or modification of debt. The assessment of this critical accounting estimate required management to apply a significant amount of judgment in evaluating the inputs, estimates, and internally generated forecast information to conclude on the accounting for the debt restructuring.

We then evaluated if the debt restructuring constituted a material modification, in which case the debt restructuring would be accounted for as an extinguishment of the original debt and the creation of new debt, resulting in the recognition of a gain or loss on the extinguishment of debt. If it was determined that the debt restructuring was a TDR, then there is no recognition of gain or loss on the extinguishment of debt, and the carrying amount of the debt is adjusted for any premium or discount that is amortized over the modification period.

Based on analysis performed and after the consideration of the applicable accounting guidance, management concluded that the debt restructuring was deemed to be a TDR. The debt restructuring was determined to be a TDR based on the creditors being deemed to have granted a concession since our effective borrowing rate of 13.93% on the restructured debt is less than the 22.15 % effective borrowing rate of the old debt immediately prior to the restructuring. Accordingly, the effects of the restructuring were accounted for prospectively from the time of the restructuring, and the restructured debt has been recorded with premiums which reflect the carrying value of the old debt less the fair value of 2,000,000 warrants for common stock issued to the creditors.

Results of Operations

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

As noted previously in this report, we operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code from March 31, 2009 until our exit from bankruptcy on May 14, 2010. Our operation over that period under Chapter 11 significantly affected our operating results, including, among other things, our incurrence of substantial expenses directly and indirectly related to our bankruptcy and the curtailment or delay of investments in our development program and normal field maintenance operations arising from the cumbersome and slow process of obtaining various approvals required for use of cash and our inability to draw on our revolving credit facility.

Oil and Gas Revenue

Oil and gas revenue for the year ended 2010 increased to $52.4 million from $47.4 million in 2009. The increase in revenue was attributable to a 25% increase in average hydrocarbon prices realized during 2010 partially offset by a 12% decrease in production volumes. The following table discloses the oil and gas sales revenues, net oil and natural gas production volumes, and average sales prices for the years ended December 31, 2010 and 2009:

		2010		2009
Revenues				
Oil	$	44,141,235	$	39,349,843
Gas		8,592,972		8,041,449
Total oil and gas revenues	$	52,734,207	$	47,391,292
Production				
Oil (Bbls)		550,000		626,900
Gas (Mcf)		1,882,800		2,114,600
Total production (Boe)		863,800		979,333
Average sales price				
Oil (per Bbl)	$	80.26	$	62.77
Gas (per Mcf)		4.56		3.80
Total average sales price (per Boe)	$	61.05	$	48.39

The decrease in production during 2010 was due to (i) limitations on our ability to offset natural production declines through development of our properties during the pendency of our bankruptcy, (ii) the unusually cold weather during the first quarter of 2010 that resulted in line freezes and a temporary cessation of production, and (iii) deferred maintenance and third party facilities capacity limitations that resulted in the shut-in or curtailment of production from a number of wells. Following our exit from bankruptcy in May 2010, we renewed our development program, although at a curtailed level supported by operating cash flow, and commenced efforts to address deferred maintenance and third party production and handling issues in order to restore shut-in, and curtailed, production. We anticipate that those efforts will begin to offset natural production declines and to grow production volumes in 2011.

The increase in average prices realized from the sale of oil and gas reflected the recovery and stabilization of oil and natural gas prices following the sharp worldwide economic decline that began during the second half of 2008 and continued to cause depressed oil and gas prices during the first half of 2009. At December 31, 2010, we were fully unhedged and, during the fourth quarter of 2010, benefited from rising oil prices.

Other Revenues

Other revenues consist principally of (i) a net profits interest attributable to operating the Breton Sound 31 field, for which we receive a percentage of profits, (ii) production handling fees from our Vermilion 16 field, and (iii) in 2010, proceeds from the sale of our Adcock Farms lease and well. For 2010, other revenues increased to $2.3 million from $1.8 million in 2009. The increase in other revenues was principally attributable to an increase in revenues relating to net profits interest from the Breton Sound 31 field and the 2010 sale of the Adcock Farms lease. During 2009, there were no net profits from the Breton Sound 31 field due to repairs as a result of the 2008 hurricane season.

Operating Expenses

Operating expenses increased to $49.2 million for 2010 from $48.8 million in 2009. The following table sets forth the components of operating expenses, in total and on a per Boe basis, for 2010 and 2009:

	2010		2009	
	Total	**Per Boe**	**Total**	**Per Boe**
Lease operating expense	$ 14,106,320	$ 16.33	$ 17,760,824	$ 18.14
Workover expense	2,154,482	2.49	2,112,090	2.16
Exploration expense	1,590,029	1.84	1,145,724	1.17
Depreciation, depletion and amortization	16,001,826	18.52	14,577,949	14.89
Accretion expense	1,668,268	1.93	1,439,437	1.47
General and administrative expenses	8,476,124	9.81	6,063,497	6.19
Production and severance taxes	5,214,677	6.04	5,672,312	5.79
	$ 49,211,726	$ 56.97	$ 48,771,833	$ 49.80

As more fully described below, the change in operating expenses was primarily attributable to increased depreciation, depletion and amortization expense, and lesser increases in workover expenses, exploration expense, accretion expense, and general and administrative expenses, partially offset by decreased lease operating expense and severance taxes.

Lease Operating Expenses

Lease operating expenses for 2010 decreased to \$14.1 million, or \$16.33 per Boe, from \$17.8 million, or \$18.14 per Boe, in 2009.

Operating costs in our fields have historically been relatively high due to water handling, the need for gas lift to maintain oil production and due to the need for marine transportation in the shallow water, bay environment. We have been actively engaged in field management efforts to reduce our lease operating expenses. A general reduction in lease operating expenses resulting from our field management efforts and the absence of certain expenses incurred during 2009 were the primary causes of reductions in lease operating expenses, and lease operating expenses per Boe, during 2010.

Workover Expense

Workover expense for 2010 increased to \$2.2 million from \$2.1 million in 2009. The increase in workover expense was attributable to extended work and development of previously producing zones from our oil and gas properties.

Exploration Expense

Exploration expense for 2010 increased to \$1.6 million from \$1.1 million in 2009. The increase in exploration expense was attributable to our ongoing full field studies on our properties for evaluation of our assets, which studies commenced in 2009 and were completed in 2010, and our purchase of a seismic license in May 2010 which accounted for \$745,000 of exploration expenses during 2010.

Depreciation, Depletion and Amortization (DD&A)

Depreciation, depletion and amortization for 2010 increased to \$16.0 million from \$14.6 million in 2009. Changes in DD&A were attributed to different production rates and added capital expenditures. DD&A is computed on the units-of-production method separately on each individual property and includes the accrual of future plugging and abandonment costs.

Accretion expense

Accretion expense for 2010 increased to $1.7 million from $1.4 million in 2009. The increase in accretion expense was attributable to increased revisions to asset retirement obligations during the prior year end causing a future impact on accretion expense compared to prior years.

General and Administrative Expenses and Other

General and administrative expense for 2010 increased to $8.5 million from $6.1 million in 2009. The increase in general and administrative expense was attributable to increases in legal expenses and consulting fees, cash bonuses paid on exit from bankruptcy, increases in salary commencing on exit from bankruptcy, and an increase in stock-based compensation due to 2010 stock option grants, all relating to increased levels of activity relating to our exit from bankruptcy and a ramp up in activities post-bankruptcy. Non-cash G&A expense, associated principally with stock-based compensation, totaled $2.5 million and $0.6 million in 2010 and 2009, respectively.

Severance Taxes

Severance taxes for 2010 decreased to $5.2 million from $5.7 million in 2009. The decrease was primarily due to refunds in severance taxes as a result of amending our states severance taxes for prior years relating to severance tax incentives. During 2010, we began taking advantage of Louisiana state severance tax incentives providing a five year severance tax exemption for previously inactive wells and, as a result we have amended prior severance tax returns through 2007 and continue to manage our monthly severance tax returns for current production. During 2010, we recorded as a reduction in production taxes certain Louisiana severance tax refunds in the amount of $0.3 million (net of $0.2 million in fees). These refunds pertain to wells certified for the incentive in 2010 and the related overpayment of severance taxes in the years 2007 and 2008. Additional refunds are expected related to the years 2007 through 2010 that will be recorded when the refund is estimable and collection is certain.

Other Income (Expense), Net

Net other income (expenses) totaled $(22.8 million) of expenses for 2010 and $(31.5 million) of expenses for 2009. The following table sets forth the components of net other income (expenses) for 2010 and 2009:

		2010		**2009**
Commodity derivative income (expense)	$	696,550	$	(4,030,004)
Loss on settlement of accounts payable		(990,786)		-
Interest income		115,350		35,811
Interest expense		(22,584,934)		(27,517,956)
	$	(22,763,820)	$	(31,512,149)

As more fully described below, the favorable changes in other income (expense), net, was principally attributable to the liquidation of our commodity derivates at a gain during the 2010 first quarter, a decrease in our interest expense based on the settled terms under our amended credit facilities and increased interest income partially offset by the incurrence during 2010 of a loss on settlement of accounts payable arising from the issuance of shares of common stock to certain creditors under our plan of reorganization.

Commodity Derivative Income (Expense)

Commodity derivative income (expense) reflects changes within a period in the prices of commodities underlying our crude oil and natural gas hedges. Pursuant to the terms of our prior term credit agreement and revolving credit agreement, we entered into certain derivative contracts to reduce the impact of changes in prices of oil and natural gas, in particular the impact of falling prices. In general, to the extent of our hedging activities, where prices of underlying commodities rise during a period we would recognize commodity derivative expense and where prices of underlying commodities decrease during a period we would recognize commodity derivative income. In the first quarter of 2010, the administrative agent for the lenders under both our term credit facility and our revolving credit facility liquidated all of our then existing commodity derivatives and applied the proceeds to amounts owed under the credit facilities. As a result of the liquidation of such positions, we realized commodity derivative income of $0.7 million during 2010 as compared to commodity derivative expense of $4.0 million during 2009. Commodity derivative expense during 2009 reflected rising oil and gas prices beginning in the second quarter of 2009.

Loss on Settlement of Accounts Payable

Loss on settlement of accounts payable is a non-recurring charge reflecting the fair value of the common stock issued to our vendors as part of the settlement terms in the Plan of Reorganization during 2010.

Interest Income (Expense), Net

Interest income (expense), net, reflects interest incurred on debt under our term credit agreement and revolving credit agreement, partially offset by interest earned on cash balances held. Net interest expense decreased to $22.5 million in 2010 from $27.5 million in 2009. The decrease in net interest expense was attributable to a decrease in our stated interest rate on our Amended and Restated Term Credit Agreement from 20% to 11.25%.

Reorganization Expenses

Reorganization expenses reflect payments to professionals and other fees incurred in connection with our Chapter 11 case. Reorganization expenses decreased to $2.2 million in 2010 from $5.7 million in 2009 due to our exit from bankruptcy in May 2010.

Income Tax Provision

For 2010, we recorded an income tax expense of $0.3 million compared to an income tax benefit of $9.7 million for 2009. The income tax expense for 2010 was attributable to Louisiana state franchise taxes. For 2010, we had a deferred tax asset and a 100% valuation allowance for federal income tax provision (benefit); therefore, we recorded no tax benefit for federal tax provision (benefit) for 2010.

The effective tax rates for 2010 and 2009 were 1.5% and 26.5%, respectively. Our effective tax rates were different than our federal statutory tax rate due to state income taxes associated with income from various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Financial Condition

Liquidity and Capital Resources

Our principal requirements for capital are to fund our day-to-day operations and exploration, development and acquisition activities and to satisfy our contractual obligations, primarily for the repayment of debt. During the pendency of our bankruptcy, we funded our operations, limited capital expenditures and debt service obligations through operating cash flow and cash on hand. Since prior to our bankruptcy filing in March 2009, we have not had access to available capital under our revolving credit agreement.

Since exit from bankruptcy, under the terms of the Plan of Reorganization, we paid out to our creditors approximately $17.3 million on exit from bankruptcy, $2.3 million during the balance of 2010, and will pay approximately $2.0 million to creditors over the first half of 2011.

We have developed a layered multi-faceted development and maintenance program designed to achieve short-, mid- and long-term objectives. Short-term, our focus is on restoration of shut-in and curtailed production through investments in infrastructure and deferred maintenance and recompletions, workovers and thru-tubing plugbacks each designed to increase or restore production volumes during the first half of 2011 from wells producing below capacity and an inventory of 63 proved developed non-producing opportunities. Mid-term, following or in conjunction with execution of short-term opportunities, our focus is on the development of an inventory of 91 proved undeveloped opportunities targeting normally pressured oil and gas. Long-term, following or in conjunction with the execution of our short- and mid-term opportunities, our focus is on continuing development of our reserves and exploratory drilling of deep shelf opportunities.

We believe that our cash flows from operations and cash on hand are sufficient to support our liquidity needs for the next twelve months, including funding all of our short-term objectives targeted for completion in 2011, including investments in planned infrastructure and deferred maintenance, recompletions, workovers and thru-tubing plugbacks. We believe that our cash flows from operations and cash on hand will also be sufficient to pursue our 2011 mid-term objectives relating to development of proved undeveloped opportunities. Our development of proved undeveloped opportunities is scalable. Depending upon the results of our short-term development initiatives, initial development efforts relating to our proved undeveloped opportunities and anticipated capital efforts, we may accelerate our planned development of proved undeveloped opportunities or otherwise adjust the nature or rate of our development program. Pursuit of our long-term plans for exploratory drilling of deep shelf prospects is expected to require funding in excess of our current resources and projected operating cash flow. At December 31, 2010, we were in active discussing with potential funding sources and drilling partners with a view to securing funding commitments to conduct initial exploratory drilling operations on our deep shelf prospects. We currently have no commitments to provide funding to support our exploratory drilling plans and there is no assurance that funding to pursue such opportunities will be available on satisfactory terms or at all. Further unexpected declines in commodity prices or production levels, or failures in achieving production increases through our short- and mid-term development plans could result in our inability to support our operations and drilling and development plans.

Beyond 2011, and in addition to our development plans, our current term and revolving credit facilities mature in April 2012. We anticipate that we will be required to retire those facilities on maturity. We do not presently have available financial resources to retire our credit facilities and will be required to seek and secure alternative financing sources to retire such facilities. At December 31, 2010, we were actively exploring and evaluating viable alternative financing sources to retire our current credit facilities when they come due in April 2012, or before. There is no assurance that we will be able to secure financing to retire our current credit facilities on acceptable terms or at all. In the event we are unable to secure sufficient financing to retire our maturing credit facilities, we may be required to liquidate some or all of our assets or may otherwise face actions by our current lender the net effect of which might be the foreclosure or other loss of some or all of our assets.

Cash, Cash Flows and Working Capital

We had a cash balance of $4.4 million and working capital of $2.6 million at December 31, 2010 as compared to a cash balance of $21.6 million and working capital of $2.8 million at December 31, 2009. The decrease in cash on hand is primarily attributable to payment to creditors on our exit from bankruptcy as provided for in our Plan of Reorganization. The decrease in working capital was primarily attributable to the reclassification of liabilities subject to compromise to payables and payment of the vast majority of such amounts on, and following, exit from bankruptcy and partially offset by the generation of cash from operations. At December 31, 2009, liabilities subject to compromise totaled $19.6 million.

Operations used cash flow of $1.4 million during 2010 as compared to providing $18.7 million during 2009. The change in operating cash flows was principally attributable to payment to creditors on our exit from bankruptcy as provided for in our Plan of Reorganization.

Investing activities used cash flows of $10.2 million during 2010 as compared to $4.4 million used during 2009. Cash used in investing activities related principally to development of oil and gas properties and reflected increased development activity in 2010 following exit from bankruptcy.

Financing activities used cash flows of $5.6 million during 2010 as compared to $1.5 million used during 2009. The change in cash flows used in financing activities was primarily attributable to $5.5 million paid toward reduction of the principal balance outstanding under our revolving credit facility on exit from bankruptcy partially offset by financing for our insurance premiums.

Debt and Non-Current Liabilities

At December 31, 2010, we had $131.8 million of indebtedness outstanding (reflecting a $4.1 million debt discount), consisting of $127.5 million under our Amended and Restated Term Credit Agreement, $7.8 million under our Amended Revolving Credit Agreement, and $0.6 million owing to officers.

Letters of credit totaling approximately $10.2 million were outstanding at December 31, 2010.

The principal terms of our debt and non-current liabilities, after giving effect to our Plan of Reorganization, were as follows:

Amended Revolving Credit Agreement. On May 14, 2010, we entered into an Amended Revolving Credit Agreement reflecting the terms described in the Plan of Reorganization. Under the Amended Revolving Credit Agreement, our revolving credit facility was revised to provide for total outstanding principal under the facility of $18.0 million, including $10.2 in letters of credit and after payment of $5.5 million. No further borrowings can be made under the Amended Revolving Credit Agreement.

The Amended Revolving Credit Agreement provides for payments of interest only on a monthly basis at a floating rate of prime plus 2% with all amounts owing under the agreement being due and payable in full on April 30, 2012.

Amended and Restated Term Credit Agreement. On May 14, 2010, we entered into an Amended and Restated Term Credit Agreement reflecting the terms described in the Plan of Reorganization. Under the Amended and Restated Term Credit Agreement, our term credit facility was revised to reflect the total amount borrowed and owing thereunder of $127.5 million and to provide for accrual of interest at 11.25% per annum payable interest only on a monthly basis with all amounts owing under the agreement being due and payable in full on April 30, 2012. The principal amount owing under the term note includes interest expense and certain reorganization costs totaling $30.0

million that were capitalized as part of the aggregate principal amount payable on the term loan.

State Lessor Audit Royalty Liability. Pursuant to the Plan of Reorganization, we are obligated to pay amounts owing with respect to a state lessor royalty audit. The total royalty audit liability of $1.3 million (includes $0.4 million in penalties) is payable over 24 equal monthly installments of $71,235 commencing February 2010.

Officer Notes. Pursuant to the Plan of Reorganization, notes payable to our Chief Executive Officer and to our President, in the aggregate amount of $0.6 million will bear compound interest at 10% per annum and are due and payable in full, with interest, in September 2013.

Capital Expenditures

Our capital spending for 2010 was $10.2 million relating primarily to development of our oil and gas properties. As a result of our operation as debtor-in-possession and inability to access our revolving credit facility, planned capital expenditures under our drilling and development program and well maintenance program were curtailed or deferred during the period through our exit from bankruptcy in May 2010.

Having exited from bankruptcy, beginning in the third quarter 2010, we restarted our development and drilling program, and a program to bring current deferred well maintenance. Our capital budget for the 2011 is focused on those projects that we believe will generate and lay the foundation for production growth and include $2.6 million budgeted for short-term deferred maintenance work planned during the first half of 2011 and targeted at bringing shut-in production back on line or increasing production from wells that are producing below capacity. Our preliminary exploration, development and other capital expenditures budget for currently planned development activities on proved undeveloped opportunities during 2011 is approximately $13.6 million. As noted, we have the operational flexibility to react quickly with our capital expenditures to changes in our cash flows from operations. Actual levels of capital expenditures in any year may vary significantly due to many factors, including the extent to which properties are acquired, drilling results, oil and gas prices, industry conditions and the prices and availability of goods and services.

Contractual Obligations

The following table details our long-term debt and contractual obligations as of December 31, 2010:

	Payments due by period				
	Total	**2011**	**2012 2013**	**2014 2015**	**Thereafter**
Debt [1]	$ 138,455,917	$ 2,673,045	$ 135,782,872	$ -	$ -
Debt related parties (includes current portion)	605,428	-	605,428	-	-
Operating leases	351,944	209,588	84,924	57,432	-
Capital leases	-	-	-	-	-
Asset retirement obligations	31,855,000	291,000	1,072,000	2,600,000	27,892,000
Total	$ 171,268,289	$ 3,173,633	$ 137,545,224	$ 2,657,432	$ 27,892,000

(1)

Debt includes (a) amounts borrowed under our amended term credit facility, in the amount of $127.5 million; (b) amounts borrowed under our amended revolving credit facility, in the amount of $7.8 million; (c) amounts payable pursuant to our Plan of Reorganization to certain unsecured creditors and oil lien claim creditors, in the amount of $1.6 million; (d) amounts payable pursuant to our Plan of Reorganization to the Louisiana Department of Mineral Resources for underpaid royalties, in the amount of $1.3 million (includes $0.4 million in penalties); and (e) installment obligations incurred relating to the acquisition of a seismic license, in the amount of $0.2 million.

Risk Management Activities   Commodity Derivative Instruments

Due to the volatility of oil and natural gas prices and requirements under our prior revolving credit agreement, historically we periodically entered into price-risk management transactions (e.g., swaps, and floors) for a portion of our oil and natural gas production. In certain cases, this allowed us to achieve a more predictable cash flow, as well as to reduce exposure from price fluctuations. The commodity derivative instruments applied to only a portion of our production, and provided only partial price protection against declines in oil and natural gas prices, and partially limited our potential gains from future increases in prices. None of these instruments were used for trading purposes.

During the first quarter of 2010, the administrative agent under our prior revolving credit agreement liquidated all of our commodity derivative instruments and applied the proceeds to indebtedness owed thereunder. Under the Amended Revolving Credit Agreement, we may not, without the consent of our lender, hedge more than 60% of our production. At December 31, 2010, we had no commodity derivative instruments in place. We intend to evaluate and, based on such evaluation, market conditions and available terms, enter into commodity derivative instruments in the future in order to manage our exposure to commodity price risk.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements or guarantees of third party obligations at December 31, 2010.

Inflation

We believe that inflation has not had a significant impact on our operations since inception.

Item 7A.

Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market-risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. Prices have fluctuated significantly during the last five years and such volatility is expected to continue, and the range of such price movement is not predictable with any degree of certainty. In the normal course of business we periodically enter into commodity derivative transactions, including fixed price and ratio swaps to mitigate exposure to commodity price movements, but not for trading or speculative purposes.

As noted above, during the first quarter of 2010, all of our natural gas and oil derivative instruments were liquidated by the administrative agent under prior credit facilities and the proceeds applied to reduction of amounts owing under those credit facilities. Under our Amended Revolving Credit Agreement, we may not, without the consent of the administrative agent for our lenders, hedge more than 60% of our production. At December 31, 2010, we had no commodity derivative instruments in place.

Interest Rate Risk

We consider our interest rate risk exposure to be minimal as a result of fixing interest rates on approximately 90 percent of our debt. At December 31, 2010, total debt included approximately $7.8 million of floating-rate debt. As a result, our annual interest cost in 2011 will fluctuate based on short-term interest rates on what is presently approximately ten percent of our total debt outstanding at December 31, 2010.

Item 8.

Financial Statements and Supplementary Data

Our financial statements appear immediately after the signature page of this report. See Index to Financial Statements on page 62 of this report.

Item 9.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A.

Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation as of December 31, 2010 of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2010.

Management s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as that term is defined in Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external reporting purposes in accordance with generally accepted accounting principles (GAAP). Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk. In addition, 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 order to evaluate the effectiveness of our internal control over financial reporting as of December 31, 2010, as required by Section 404 of the Sarbanes-Oxley Act of 2002, our management conducted an assessment, including testing, based on the criteria set forth in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO Framework). A material weakness is a control deficiency, or a combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of our annual or interim financial statements will not be prevented or detected.

Based on the evaluation performed, management concluded that our internal control over financial reporting was effective as of December 31, 2010.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management s report was not subject to attestation by our registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit smaller reporting companies to provide only management s report in this annual report.

Changes in Internal Control over Financial Reporting

No change in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) occurred during the fourth quarter of fiscal 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B.

Other Information

Not applicable

PART III

Item 10.

Directors, Executive Officers and Corporate Governance

Executive Officers and Directors

The following table sets forth the names, ages and offices of our present executive officers and directors.

Name	Age	Position
Thomas F. Cooke	62	Chief Executive Officer and Chairman
Andrew Clifford	56	President and Director
Edward Hebert	38	Vice President Finance
Brian Daigle	51	Vice President Operations
Kevin Smith	66	Director
Rex White	78	Director

The following is a biographical summary of the business experience of our directors and executive officers:

Thomas F. Cooke co-founded our company in 1990 and has served as our Chief Executive Officer and Chairman since October 2007. Mr. Cooke served as our President, Chief Executive Officer and Chairman from 1996 to 2007. In addition, Mr. Cooke has been self-employed as an independent oil and gas producer and investor for more than 20 years.

Andrew C. Clifford has served as our President and a Director since October 2007. He is a petroleum geologist/geophysicist with over 25 years of experience. Mr. Clifford s experience includes providing professional geological services on prospects throughout the United States and around the world as an independent consultant, as Vice President of Exploration for BHP Petroleum and as a Senior Geophysicist for BHP Petroleum, Kuwait Foreign Petroleum and Esso Exploration. Prior to joining the company, Mr. Clifford was a co-founder and Executive Vice President of Aurora Gas, LLC, an independent gas developer and producer with gas production operations in Cook Inlet, Alaska. Mr. Clifford holds a B.Sc, with honors, in Geology with Geophysics from London University and is a frequent speaker and published author on a variety of energy industry topics.

Edward Hebert has served as our Vice President Finance and Chief Accounting Officer since September 2008. Mr. Hebert is a CPA with broad energy industry experience. Prior to joining the company, Mr. Hebert served as Vice President of Finance for Internet REIT, Inc., a privately held internet media company, from 2006 to 2008; and, as Vice President and Controller of Particle Drilling Technologies, Inc., a Nasdaq-listed oilfield services company, from 2004 to 2006. Previously, Mr. Hebert held accounting, auditing and financial consulting positions, both within and outside of the energy industry, with Prejean Company, Arena Energy and the Energy Division of Arthur Andersen.

Brian Daigle has served as our Vice President Operations since July 2010. Previously, Mr. Daigle served as Operations Manager of the Harvest Companies since 2006 and is responsible for the day-to-day management of the companies physical assets. Prior to joining the Harvest Companies, from 2004 to 2006 Mr. Daigle was self-employed as a consultant to various operators providing operations management, technical support for facility installation, and managing daily production operations. Mr. Daigle served as Production Superintendent for Denbury Resources from 2001 to 2004. Mr. Daigle has more than 25 years of diversified experience in the oil and gas industry focused on production operations, facility design, regulatory compliance, and project management in the Gulf of Mexico and inland waters of the State of Louisiana.

Kevin M. Smith has served as a Director of our company since 1997. Mr. Smith has in excess of 35 years experience as an exploration geophysicist. Since 1984 Mr. Smith's work experience has been exclusively devoted to his own geophysical consulting firm (Kevin M. Smith, Inc.). Mr. Smith received a Bachelor of Science degree with a dual major of Geology and Geophysics from the University of Houston. He also did post graduate studies in Geology and Geophysics at the University of Houston.

Rex H. White has served as a Director of our company since 2006. Mr. White is an attorney, Board Certified in Oil, Gas and Mineral Law, with over 45 years of experience in the energy industry. Prior to commencing his legal career, Mr. White worked as a petroleum geologist/geophysicist for approximately 10 years. Mr. White s career in the energy industry includes service as Special Counsel to the Texas Railroad Commission, Assistant Attorney General of the State of Texas, President of the Texas Independent Producer and Royalty Owners Association, and a Presidential appointment to The National Petroleum Council. Mr. White holds a B.S. in Geology, a M.A. in Geology with a minor in Petroleum Engineering and a law degree all from the University of Texas.

There are no family relationships among the executive officers and directors. Except as otherwise provided in employment agreements, each of the executive officers serves at the discretion of the Board.

Advisory Directors

In addition to our officers, directors and key employees, we maintain a board of advisors that provide advice to our management team and consulting services on an as needed basis.

Bill Rhea. Since October 2007, J.W. Bill Rhea has served as an advisory director. Mr. Rhea has over 30 years of business, financial and petroleum engineering experience in all phases of the upstream oil and gas industry, onshore and offshore, both domestically and internationally on four continents. Mr. Rhea is a second-generation oil and gas businessman and, in addition to serving in senior management and chief executive roles in several independent oil and gas companies (public and private), has also been a consultant to industry. Mr. Rhea is steeply versed in the prospect generation and assembly process using state of the art remote sensing and focusing technologies coupled with more traditional 2D and 3D seismic technologies to assemble, drill, and develop world class prospects. Over his career, Mr. Rhea has also worked on acquisitions, mergers, and divestitures of oil and gas assets and companies. Mr. Rhea is currently a petroleum exploration consultant.

Fred Aminzadeh, Ph.D. Since September 2010, Dr. Fred Aminzadeh has served as an advisory director and, through his consulting firm, has provided technical consulting services to our company. Dr. Aminzadeh is a research professor at the University of Southern California s Center for Integrated Smart Oil Fields (CiSoft) and is associated with USC Energy Institute. Before joining USC, he served as president and CEO of dGB Earth Sciences USA, a leading seismic services and software company, worked in various technical and management positions with Unocal for 17 years and held a number of full time and part time academic positions, including serving as an adjunct professor in the Geosciences Department at Rice University. Dr. Aminzadeh holds a Ph. D. from University of Southern California. He is a member of, and has served in, numerous industry and professional organizations, including service as president of Society of Exploration Geophysicists, fellow of the IEEE, chairman of SEG Research Committee, chairman of the advisory board of Western Standard Energy Corp. and a member of DOE s Unconventional Resources Technology Advisory Committee, the Russian Academy of Science, the Azerbaijan Oil academy, and the National Research Council s Committee on Seismology. Dr. Aminzadeh holds three patents and is extensively published in diverse areas including eleven books on areas such as Reservoir Characterization, Petroleum Geology of South Caspian Basin, 3-D Seismic Modeling Advances in Seismic Data Processing, Geophysics for Engineers, and Petroleum Industry Applications of Pattern Recognition and Soft Computing. During 2010, Dr. Aminzadeh, through his consulting firm, provided paid consulting services to our company in evaluating the application of specific technologies to evaluate our deep gas objectives and developing technical studies to enhance existing exploration and production activities.

David Wilde. Since September 2010, David Wilde has served as an advisory director and, through his consulting firm, has provided financial consulting services to our company. Mr. Wilde is a seasoned oil and gas industry veteran with more than 20 years of broad experience in capital market transactions, asset acquisitions and divestitures, corporate development, strategic planning and other financial functions. Since 2008, Mr. Wilde has been President and CFO of Terramar Resources, Inc. and Managing Member of Terramar Partners, LLC. Mr. Wilde co-founded and became a director of Millennium Offshore Group in 2000 where he participated in the successful development and execution of an acquire and exploit strategy. Mr. Wilde assumed the positions of President and CFO of Millennium Offshore Group in 2005 where he led a restructuring that included a $25 million capital infusion, a 40% reduction in operating costs while managing a $60 million drilling budget and the ultimate divestiture of its assets. From 1995 to 2005, Mr. Wilde served as Director of Corporate Development of KCS Energy, Inc. Mr. Wilde previously held positions with Union Texas Petroleum and Plains Resources. Mr. Wilde holds a B.A. in Management Sciences from Duke University and an M.B.A. in Finance and Management from the University of Texas. During 2010, Mr. Wilde, through Terramar Resources, provided paid consulting services to our company in enhancing our market position, optimizing financial structures to support accelerated development of existing reserves, establishing key industry partnerships to accelerate drilling of deep gas prospects and identifying and negotiating strategic acquisition opportunities.

Key Employees

Elizabeth Goodman. Ms. Goodman has served as Geophysical Supervisor for the Harvest Companies since 2005 and is responsible for evaluating the oil and gas potential of the companies asset base by assimilation of geological and 3D seismic data. Prior to joining the Harvest Companies, from 2002 to 2005 Ms. Goodman served as an independent consultant to operators utilizing her geophysical expertise to identify remaining oil and gas potential. Ms. Goodman has also served in various positions at Denbury Resources, Matrix Oil & Gas, and Texaco Exploration & Production. Ms. Goodman has more than 25 years experience in oil and gas development, specializing in the integration of geological, geophysical and engineering data for prospect delineation and risk evaluation.

Steve Freeman. Mr. Freeman has served as Senior Production Engineer for the Harvest Companies since 2005 and is responsible for the planning, coordinating and supervision of well work operations, as well as working closely with reservoir engineers, geologists and operations managers/production superintendents to optimize production and identify new well work opportunities. Mr. Freeman served as Production Engineer for Forest Oil Corporation from 2004 to 2005 and as Area Operations Engineer for Denbury Resources from 2001 to 2004. Mr. Freeman also served in various positions at Matrix Oil & Gas and Chevron. Mr. Freeman has more than 25 years experience in domestic oil and gas operations, specializing in production, workover, and completion operations.

Mindy Stuart. Ms. Stuart has served as Asset Evaluation Manager since July 2010 and is responsible for all reservoir engineering functions within our company, including reserve evaluation as well as acquisitions and divestitures. Ms. Stuart has more than 25 years of industry experience in reservoir engineering and asset management in the Gulf Coast region with Bayou Bend Petroleum, Coldren Oil and Gas, Stone Energy and Chevron, and provided reservoir engineering services to our company as a consultant from early 2009 until joining our company in 2010.

Board Committees

The board currently has, and appoints members to, two standing committees: the audit committee and the compensation committee. Each member of these committees is independent as defined by applicable AMEX and SEC rules. Each of the committees has a written charter approved by the board.

Audit Committee

The audit committee is composed of two non-employee directors, Messrs. Smith and White, each of whom meets the independence and financial literacy requirements as defined by applicable AMEX rules. The audit committee assists the Board in general oversight of our financial reporting, internal controls, legal compliance, ethics programs and audit functions, and is directly responsible for the appointment, evaluation, retention and compensation of the registered public accounting firm. The Board has determined that none of the present members of the audit committee qualifies as an audit committee financial expert in accordance with the applicable rules and regulations of the SEC.

Compensation Committee

The compensation committee is composed of two non-employee directors, Messrs. Smith and White, each of whom meets the independence requirement as defined by applicable AMEX rules. The committee is responsible for establishing and administering the policies that govern annual compensation. It reviews and approves salaries, bonus and incentive compensation, perquisites, equity compensation, and all other forms of compensation for our executive officers, including the chief executive officer. The compensation committee is also responsible for reviewing and administering our incentive compensation plans, equity incentive programs and other benefit plans. It periodically reviews and makes recommendations to the Board with respect to director compensation.

Nomination of Directors

The board of directors does not maintain a standing Nominating Committee. Instead, the Board has adopted, by resolution, a process of nominating directors wherein nominees must be selected, or recommended for the Board s selection, by a majority of the independent directors with independence determined in accordance with AMEX standards. Because of the relatively small size of the Board and the current demands on the independent directors, the Board determined that the nomination process would best be carried out, while maintaining the independence of the nominating process, by drawing upon the resources of all Board members with the requirement that nominees be selected by a majority of the independent directors.

In the event of a vacancy on the Board, the process followed by the independent directors in nominating and evaluating director candidates includes requests to Board members and others for recommendations, meetings from time to time to evaluate biographical information and background material relating to potential candidates and interviews of selected candidates by members of the Board.

In considering whether to recommend any particular candidate for inclusion in the Board s slate of recommended director nominees, the independent directors apply criteria adopted by the Board. These criteria include the candidate s integrity, business acumen, knowledge of our business and industry, experience, diligence, absence of conflicts of interest and the ability to act in the interests of all stockholders. No specific weights are assigned to particular criteria and no particular criterion is a prerequisite for each prospective nominee. The Board does not have a formal policy with respect to diversity of nominees. We believe that the backgrounds and qualifications of our directors, considered as a group, should provide a composite mix of experience, knowledge and abilities that will best allow the board to fulfill its responsibilities.

The Board may utilize the services of a search firm to help identify candidates for director who meet the qualifications outlined above.

Stockholders may recommend individuals to the independent directors for consideration as potential director candidates by submitting their names, together with appropriate biographical information and background materials and a statement as to whether the stockholder or group of stockholders making the recommendation has beneficially owned more than 5% of our common stock for at least a year as of the date such recommendation is made, to Independent Directors, c/o Corporate Secretary, Saratoga Resources, Inc., 7500 San Felipe, Suite 675, Houston, Texas 77063. Assuming that appropriate biographical and background material has been provided on a timely basis, the stockholder-recommended candidates will be evaluated by following substantially the same process, and applying substantially the same criteria, as it follows for candidates recommended by our Board or others. If the Board determines to nominate a stockholder-recommended candidate and recommends his or her election, then his or her name will be included in the proxy card for the next annual meeting.

Board Leadership Structure and Risk Oversight Role

Our Chief Executive Officer also serves as Chairman of our Board of Directors and we do not presently maintain a Lead Independent Director . We believe that such a leadership structure is appropriate for our company given the small size of our company and our need to control costs and facilitate rapid response to matters arising in the course of our operations.

Our Board provides high level oversight to our risk management activities, consisting principally of interfacing with management with regard to proper risk management policies and implementation of those policies through commodity derivative transactions. In general, the Board familiarizes itself with the risk management policies being pursued and the actual transactions carried out in that regard so as to assure that the policy is sound and the transactions undertaken are consistent with the policy. Given the contractual limitations of our revolving credit facility, the Board believes that our company and management has little discretion with regard to risk management transactions.

Code of Ethics

The Board of Directors has adopted a Code of Business Ethics covering all of our officers, directors and employees. We require all employees to adhere to the Code of Business Ethics in addressing legal and ethical issues encountered in conducting their work. The Code of Business Ethics requires that our employees avoid conflicts of interest, comply with all laws and other legal requirements, conduct business in an honest and ethical manner and otherwise act with integrity and in the company's best interest.

The Board of Directors has also adopted a separate Code of Business Ethics for the CEO and Senior Financial Officers. This Code of Ethics supplements our general Code of Business Ethics and is intended to promote honest and ethical conduct, full and accurate reporting, and compliance with laws as well as other matters.

The Code of Business Ethics for the CEO and Senior Financial Officers was filed as an exhibit to the Annual Report on Form 10-KSB for the year ended December 31, 2005 and is available for review at the our web site at www.saratogaresources.net.

Compliance with Section 16(a) of Exchange Act

Under the securities laws of the United States, our directors, executive officers, and any person holding more than ten percent of our common stock are required to report their initial ownership of common stock and any subsequent changes in that ownership to the Securities and Exchange Commission. Specific due dates for these reports have been established and we are required to disclose any failure to file by these dates during fiscal year 2010. To our knowledge, all of the filing requirements were satisfied on a timely basis in fiscal year 2010. In making these disclosures, we have relied solely on copies of reports provided to us.

Item 11.

Executive Compensation

Named Executive Officers

The following table sets forth in summary form the compensation earned during each of the two years ended 2010 by our named executive officers and highest paid employees:

Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards ($)	Option Awards ($)[1]	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)[2]	Total ($)
Thomas Cooke, CEO	2010	258,125	55,000					8,333	321,458
	2009	180,000	15,000					8,400	203,400
Andy Clifford, President	2010	258,125	55,000					20,916	334,041
	2009	180,000	15,000					8,400	203,400
Edward Hebert, Vice President Finance	2010	167,500			621,000			6,701	795,201
	2009	155,000							155,000
Brian Daigle, Vice President Operations (3)	2010	165,000			241,200			6,352	412,552
	2009	150,000		66,300				5,500	221,800

---

(1)

The amounts included in the Option Awards column reflect the grant date fair value calculated in accordance with FASB ASC Topic 718. The Company s FASB ASC Topic 718 assumptions used in these calculations are set forth in Note 11 to the Financial Statements included in this annual report on Form 10-K. See Grants of Plan-Based Awards for details with respect to the terms of the stock options awarded during 2010.

(2)

All other compensation consists of:

Name and Principal Position	Year	Auto Allowance	401k Plan Contribution
Thomas Cooke	2010	8,333	
	2009	8,400	
Andy Clifford	2010	8,388	12,528
	2009	8,400	
Edward Hebert	2010		6,701
	2009		
Brian Daigle	2010		6,352
	2009		5,500

(3)

Mr. Daigle was appointed Vice President Operations of the company on July 1, 2010. Prior to that date, Mr. Daigle was employed by the company in a non-executive capacity. The compensation shown includes all compensation paid to Mr. Daigle, including amounts paid prior to his appointment as an executive officer.

Grants of Plan-Based Awards

The following table sets forth information regarding plan-based awards to our named executive officers in 2010.

Name	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units (#)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($)(1)
Edward Hebert	07/15/10		100,000	1.71	171,000
	04/14/10		150,000	3.00	450,000

Brian Daigle	07/01/10	40,000	1.53	61,200
	04/14/10	60,000	3.00	180,000

(1)

Reflects the grant date fair value calculated in accordance with FASB ASC Topic 718. The company s FASB ASC Topic 718 assumptions used in these calculations are set forth in Note 11 to the Financial Statements included in this annual report on Form 10-K.

Outstanding Equity Awards at Fiscal Year-End

The following table includes certain information with respect to the number of all unexercised options previously awarded to the named executive officers at December 31, 2010.

	Option Awards				
Name	Number of Securities Underlying Unexercised Options Exercisable (#)	Number of Securities Underlying Unexercised Options Unexercisable (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date
Edward Hebert	-	100,000[(1)]	-	1.71	07/15/20
	150,000	-	-	3.00	04/14/20
Brian Daigle	-	40,000[(2)] [(3)]	-	1.71	07/01/20
	30,000	30,000	-	3.00	04/14/20

(1)

Options become exercisable over a three year period with 33% vesting on July 15, 2011, an additional 33% vesting on July 15, 2012 and the remaining 33% vesting on July 15, 2113.

(2)

Options become exercisable over a three year period with 33% vesting on July 1, 2011, an additional 33% vesting on July 1, 2012 and the remaining 33% vesting on July 1, 2113.

(3)

Options become exercisable July 1, 2011.

Employment Agreements

Thomas F. Cooke. In October 2007, we entered into an employment agreement with Thomas F. Cooke pursuant to which Mr. Cooke serves as our Chairman and Chief Executive Officer for the duration of the term of said employment agreement. The employment agreement provides for an annual salary, participation in all of our executive benefit programs and discretionary raises and bonuses as determined by our board of directors. The employment agreement provided for an initial term of three years with automatic one year renewals thereafter unless we notify Mr. Cooke of our intent not to renew the employment agreement. The current term of the employment agreement expires in October 2011, subject to the automatic renewal provision, and the current annual salary under the employment agreement is $305,000.

Andrew C. Clifford. In October 2007, we entered into an employment agreement with Andy Clifford pursuant to which Mr. Clifford serves as our President for the duration of the term of said employment agreement. The employment agreement provides for an annual salary, participation in all of our executive benefit programs and discretionary raises and bonuses as determined by our board of directors and an initial restricted stock grant. The employment agreement provided for an initial term of three years with automatic one year renewals thereafter unless we notify Mr. Clifford of our intent not to renew the employment agreement. The current term of the employment agreement expires in October 2011, subject to the automatic renewal provision, and the current annual salary under the employment agreement is $305,000.

2006 Employee and Consultant Stock Plan

In January 2006, our Board of Directors adopted the Saratoga Resources, Inc. 2006 Employee and Consultant Stock Plan (the Stock Plan).

Pursuant to the Stock Plan, 1,200,000 shares of common stock were reserved for issuance to employees and consultants as compensation for past or future services or the attainment of goals. In October 2007, the Stock Plan was amended to increase the shares reserved thereunder to 2,525,000.

The Stock Plan is administered by the Board of Directors subject to the right of the Board of Directors to appoint a committee of the Board of Directors to administer the same.

2008 Long-Term Incentive Plan

Effective October 17, 2008, we adopted the Saratoga Resources, Inc. 2008 Long-term Incentive Plan (the 2008 Plan). The 2008 Plan reserves a total of 3,000,000 for issuance to eligible employees, officers, directors and other service providers pursuant to grants of options, restricted stock, performance stock and other equity based compensation arrangements. As of December 31, 2010, no awards had been made under the 2008 Plan.

Directors

The following table sets forth the compensation paid to directors during 2010:

	Fees Earned or Paid in Cash ($)	Stock Awards ($)	Option Awards ($)(1)(2)	Non-Equity incentive Plan Compensation ($)	All other Compensation ($)	Total ($)
Kevin Smith			75,000			75,000
Rex White			75,000			75,000

(1)

The dollar amounts reflect the aggregate grant date fair value of the options computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of this amount are included in Note 11 to our audited financial statements for the fiscal year ended December 31, 2010.

(2)

The following are the aggregate number of option awards outstanding that have been granted to each of our non-employee directors as of December 31, 2010: Mr. Smith: 50,000; and Mr. White: 50,000.

Beginning in 2009, the only compensation paid for services of non-employee directors, other than reimbursement of expenses associated with service as such, is the annual grant of 25,000 stock options. We may consider payment of certain additional amounts for services of directors in the future.

Item 12.

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth information as of March 8, 2011, based on information obtained from the persons named below, with respect to the beneficial ownership of shares of our common stock held by (i) each person known by us to be the owner of more than 5% of the outstanding shares of our common stock, (ii) each director, (iii) each named executive officer, and (iv) all executive officers and directors as a group:

Name and Address of Beneficial Owner [1]	Number of Shares Beneficially Owned [1]	Percentage of Class [2]
Thomas F. Cooke [4]	6,140,422(3)	35.4%
Andrew C. Clifford [4]	2,635,059(5)	15.2%
Kevin Smith	303,643(6)	1.7%
Rex H. White	102,500(7)	*
Brian Daigle	90,000(8)	*
Edward Hebert	150,000(9)	*
Macquarie Americas Corp. [10]	3,300,000	19.0%
All directors and officers as a group (6 persons)	9,421,624	53.5%

---

*

Less than 1%.

(1)

Unless otherwise indicated, each beneficial owner has both sole voting and sole investment power with respect to the shares beneficially owned by such person, entity or group. The number of shares shown as beneficially owned include all options, warrants and convertible securities held by such person, entity or group that are exercisable or convertible within 60 days of March 8, 2011.

(2)

The percentages of beneficial ownership as to each person, entity or group assume the exercise or conversion of all options, warrants and convertible securities held by such person, entity or group which are exercisable or convertible within 60 days, but not the exercise or conversion of options, warrants and convertible securities held by others shown in the table.

(3)

Includes 104,148 shares held by June Cooke, Mr. Cooke s spouse, of which Mr. Cooke disclaims beneficial ownership.

(4)

Address is c/o Saratoga Resources, Inc., 7500 San Felipe, Suite 675, Houston, Texas.

(5)

Includes 4,173 shares held by his spouse in a SEP-IRA and 5,886 shares held by his SEP-IRA. Includes 2,500,000 shares held by CPK Resources, LLC of which Mr. Clifford is the principal officer and owner.

(6)

Includes 20,000 shares held by Sandra Smith, Mr. Smith s spouse, of which Mr. Smith disclaims beneficial ownership, and 50,000 shares underlying presently exercisable stock options.

(7)

Includes 50,000 shares underlying presently exercisable stock options.

(8)

Includes 30,000 shares underlying presently exercisable stock options.

(9)

Includes 150,000 shares underlying presently exercisable stock options.

(10)

Address is 125 W. 55th Street, 22nd Floor, NY, NY. Based upon information regarding holdings reported on a Schedule 13D filed with the SEC on July 24, 2008 by Macquarie Americas Corp.

(11)

Includes 280,000 shares underlying presently exercisable stock options.

Item 13.

Certain Relationships and Related Transactions, and Director Independence

Officer Loans

In conjunction with the closing of the Harvest Acquisitions, during 2008, we issued subordinated promissory notes to Thomas F. Cooke and Andrew C. Clifford, our principal shareholders and officers, evidencing accrued salaries and expenses owing to those officers. The notes were subordinated to the rights of our senior lenders, accrued interest at 10% per annum and were repayable in equal monthly installments of principal and interest over three years.

Pursuant to our bankruptcy filing, no payments were made on the notes to Messrs. Cooke and Clifford following the Petition Date. As part of the Plan of Reorganization, the notes owing to Messrs. Cooke and Clifford were modified to eliminate the payment of monthly installments, to provide that interest would be accrued and compounded annually and to provide for the payment in full of the notes, including accrued interest, forty months following the Effective Date of the Plan, and subject to the prior payment of all amounts owed with respect to allowed claims in the bankruptcy.

At December 31, 2010, principal amounts owing under the notes (excluded accrued and unpaid interest) to Messrs. Cooke and Clifford totaled $482,932 and $122,500, respectively. During 2010, interest in the amount of $84,678 and $21,479, respectively, was accrued on the notes to Messrs. Cooke and Clifford. No payments of principal or interest were made on the notes during 2010. During 2009, we made payments of interest on the notes to Messrs. Cooke and Clifford in the amounts of $12,333 and $3,128, respectively.

Transactions with Macquarie and Affiliates

In connection with the Harvest Acquisitions, we issued 3,300,000 shares of common stock to Macquarie Americas Corp., making Macquarie Americas Corp. a principal shareholder of our company. Also, in conjunction with the Harvest Acquisitions, we entered into the 2008 Revolving Credit Agreement with Macquarie Bank Limited, an affiliate of Macquarie Americas Corp. Pursuant to the terms of the Revolving Credit Agreement, Macquarie Bank Limited agreed to provide a revolving credit loan facility in an amount up to $25,000,000 and we granted to Macquarie Bank Limited a first lien on substantially all of our assets. Macquarie Bank subsequently sold all of its right and interest under the 2008 Revolving Credit Agreement.

Interest paid to Macquarie Bank totaled approximately $569,000 during 2009. No interest payments were made to Macquarie Bank during 2010 and no amounts were owing to Macquarie Bank at December 31, 2010.

Item 14.

Principal Accountant Fees and Services

The following table presents fees billed for professional services rendered by our principal accountants for the audit of our annual financial statements for the years ended December 31, 2010 and 2009 and fees billed for other services rendered by that firm during those periods.

	2010	2009
Audit fees [1]	$ 255,813	$ 171,333
Audit related fees		-
Tax fees	34,521	20,613
All other fees		-
Total	$ 290,334	$ 191,946

(1)

Audit fees consist of fees billed for professional services rendered for the audit of our consolidated annual financial statements and review of the interim consolidated financial statements included in quarterly reports and services that are normally provided in connection with statutory and regulatory filings or engagements.

The policy of our board Audit Committee is to pre-approve all audit and non-audit services provided by the independent auditors.

PART IV

Item 15.

Exhibits and Financial Statement Schedules

1.

Financial statements. See Index to Financial Statements on page 62 of this report.

2.

Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date Filed	Number	Filed Herewith
2.1	Third Amended Plan of Reorganization of Saratoga Resources, Inc. and its affiliated debtors, Modified March 31, 2010	10-K	4/14/10	2.1	
3.1	Restated Articles of Incorporation of Saratoga Resources, Inc. with amendments, dated May 14, 2010	8-K	5/18/10	3.1	
3.2	Bylaws of Saratoga Resources, Inc.	10-SB	10/6/99	3(ii)	
10.1	Saratoga Resources, Inc. 2006 Employee and Consultant Stock Plan*	8-K	1/30/06	10.2	
10.2	Amendment No. 1 to 2006 Employee and Consultant Stock Plan*	8-K	10/11/07	10.1	
10.3	Saratoga Resources, Inc. 2008 Long-term Incentive Plan*	10-Q	11/19/08	10.1	
10.4	Employment Agreement, dated October 9, 2007, with Thomas Cooke*	8-K	10/11/07	10.2	
10.5	Employment Agreement, dated October 8, 2007, with Andrew Clifford*	8-K	10/11/07	10.3	
10.6	Stock Grant Agreement, dated October 8, 2007, with Andrew Clifford*	8-K	10/11/07	10.4	
10.7	Amended and Restated Credit Agreement, dated July 14, 2008, between Saratoga Resources, Inc. and Macquarie Bank Limited	8-K	7/18/08	10.4	
10.8	First Amendment to Amended and Restated Credit Agreement, dated May 14, 2010, between Saratoga Resources, Inc., and its affiliates, and	8-K	5/18/10	10.1	

	Wayzata Investment Partners, LLC				
10.9	Amended and Restated Credit Agreement, dated May 14, 2010, between Saratoga Resources, Inc., and its affiliates, and Wayzata Investment Partners, LLC	8-K	5/18/10	10.2	
10.10	Wayzata Investment Partners LLC Warrant, dated July 14, 2008	8-K	7/18/08	10.5	
10.11	Wayzata Investment Partners LLC Warrant, dated May 14, 2010	8-K	5/18/10	10.3	
10.12	Subordinated Promissory Note, dated July 14, 2008, payable to Thomas F. Cooke	8-K	7/18/08	10.6	
10.13	Subordinated Promissory Note, dated July 14, 2008, payable to Andrew C. Clifford	8-K	7/18/08	10.7	
14.1	Code of Ethics for CEO and Senior Financial Officers	10-KSB	1/25/06	14.1	
21.1	List of subsidiaries	10-K	4/14/10	21.1	
23.1	Consent of Malone & Bailey, P.C.				X
23.2	Consent of Collarini Associates				X
31.1	Section 302 Certification of CEO				X
32.2	Section 302 Certification of CFO				X
32.1	Section 906 Certification of CEO				X
32.2	Section 906 Certification of CFO				X
99.1	Reserve Report of Independent Engineer				X

*

Compensatory plan or arrangement.

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.

SARATOGA RESOURCES, INC.

Dated:	By:	/s/ Thomas F. Cooke
March 10, 2011		Thomas F. Cooke Chairman 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/ Thomas F. Cooke Thomas F. Cooke	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	Dated: March 10, 2011
/s/ Andrew C. Clifford Andrew C. Clifford	President and Director	Dated: March 10, 2011
/s/ Kevin Smith Kevin Smith	Director	Dated: March 10, 2011
/s/ Rex H. White Rex H. White	Director	Dated: March 10, 2011
/s/ Edward Hebert	Vice President Finance	Dated:

		March 10, 2011
Edward Hebert	(Principal Accounting and Financial Officer)	

SARATOGA RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Saratoga Resources, Inc

Houston, Texas

We have audited the consolidated balance sheets of Saratoga Resources, Inc. and subsidiaries (Company) as of December 31, 2010 and 2009, and the related consolidated statements of operations, shareholders equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on the 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2010 and 2009, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ MALONEBAILEY, LLP

www.malone-bailey.com

Houston, Texas

March 10, 2011

Saratoga Resources, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2010	**2009**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 4,409,984	$ 21,575,483
Accounts receivable	9,039,836	7,379,654
Prepaid expenses and other	888,717	1,184,468
Derivative asset	-	328,980
Other current asset	300,000	-
Total current assets	14,638,537	30,468,585
Property and equipment:		
Oil and gas properties - proved (successful efforts method)	170,870,775	160,709,425
Other	561,572	537,280
	171,432,347	161,246,705
Less: Accumulated depreciation, depletion and amortization	(37,597,980)	(21,596,154)
Total property and equipment, net	133,834,367	139,650,551
Other assets, net	2,870,379	3,719,405
Total assets	$ 151,343,283	$ 173,838,541
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 4,655,874	$ 2,673,078
Revenue and severance tax payable	5,071,508	3,773,503
Accrued liabilities	1,649,994	19,910,354
Short-term notes payable	285,298	414,257
Asset Retirement Obligation - current	332,863	873,103
Total current liabilities	11,995,537	27,644,295
Long-term liabilities		
Asset retirement obligation	11,653,212	9,316,970
Derivative liabilities	-	764,029
Long-term debt, net of discount of $4,140,662 and $1,217,578, respectively	131,200,209	108,811,300
Long-term debt related parties	605,428	-
Total long-term liabilities	143,458,849	118,892,299
Liabilities subject to compromise	-	19,631,567
Commitment and contingencies (see notes)		
Stockholders' equity (deficit):		

Common stock, $0.001 par value; 100,000,000 shares authorized 17,298,598 and 16,690,292 shares issued and outstanding at December 31, 2010 and 2009, respectively		17,298		16,690
Additional paid-in capital		27,547,251		19,887,814
Retained earnings		(31,675,652)		(12,234,124)
Total stockholders' equity (deficit)		(4,111,103)		7,670,380
Total liabilities and stockholders' equity (deficit)	$	151,343,283	$	173,838,541

See notes to consolidated and combined financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31, 2010	2009
Revenues:		
Oil and gas revenues	$ 52,734,207	$ 47,391,292
Other revenues	2,284,008	1,834,999
Total revenues	55,018,215	49,226,291
Operating Expense:		
Lease operating expense	14,106,320	17,760,824
Workover expense	2,154,482	2,112,090
Exploration expense	1,590,029	1,145,724
Depreciation, depletion and amortization	16,001,826	14,577,949
Accretion expense	1,668,268	1,439,437
General and administrative	8,476,124	6,063,497
Severance taxes	5,214,677	5,672,312
Total operating expenses	49,211,726	48,771,833
Operating income	5,806,489	454,458
Other income (expense):		
Commodity derivative income (expense), net	696,550	(4,030,004)
Loss on settlement of accounts payable	(990,786)	-
Interest income	115,350	35,811
Interest expense	(22,584,934)	(27,517,956)
Total other expense	(22,763,820)	(31,512,149)
Net loss before reorganization expenses and income taxes	(16,957,331)	(31,057,691)
Reorganization expenses	2,198,359	5,656,499
Net loss before income taxes	(19,155,690)	(36,714,190)
Income tax provision (benefit)	285,838	(9,719,825)
Net loss	$ (19,441,528)	$ (26,994,365)
Net loss per share basic and diluted	$ (1.14)	$ (1.62)
Weighted average number of common shares outstanding basic and diluted	16,996,166	16,687,561

See notes to consolidated and combined financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (DEFICIT)

	Common Stock			Additional Paid-in		Net Income		Total Stockholders
	Shares		**Amount**		**Capital**		**(Loss)**		**Equity (Deficit)**
Balance, December 31, 2008	16,877,792	$	16,878	$	19,309,658	$	14,760,241	$	34,086,777
Common stock issued for services	12,500		12		3,593		-		3,605
Restricted stock forfeited	(200,000)		(200)		200		-		-
Fair value of warrants issued for services	-		-		2,525		-		2,525
Stock-based employee compensation	-		-		571,838		-		571,838
Net loss	-		-		-		(26,994,365)		(26,994,365)
Balance December 31, 2009	16,690,292		16,690		19,887,814		(12,234,124)		7,670,380
Common stock issued to settle accounts payable	483,306		483		990,302		-		990,785
Common stock issued for services	125,000		125		287,375		-		287,500
Fair value of warrants issued in connection with debt restructuring	-		-		4,099,116		-		4,099,116
Fair value of warrants issued for services	-		-		120,000		-		120,000

Stock-based employee compensation	-		-		2,162,644		-		2,162,644
Net loss	-		-		-		(19,441,528)		(19,441,528)
Balance December 31, 2010	17,298,598	$	17,298	$	27,547,251	$	(31,675,652)	$	(4,111,103)

See notes to consolidated and combined financial statements.

F-4

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ (19,441,528)	$ (26,994,365)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation, depletion and amortization	16,001,826	14,577,949
Accretion expense	1,668,268	1,439,437
Amortization of debt issuance costs	526,397	751,738
Amortization of debt discount	1,965,993	522,672
Commodity derivative (income) expense	(473,962)	8,812,571
Stock-based compensation	2,570,144	577,968
Loss on settlement of accounts payable	990,785	-
Abandonment costs	(153,655)	-
Deferred taxes	-	(9,838,825)
Changes in operating assets and liabilities:		
Accounts receivable	(1,660,182)	660,243
Prepaids and other	295,751	1,622
Accounts payable	(11,556,869)	1,051,123
Revenue and severance tax payable	(841,880)	5,134,090
Accrued liabilities	8,742,503	22,043,934
Net cash provided (used) by operating activities	(1,366,409)	18,740,157
Cash flows from investing activities:		
Additions to oil and gas property	(9,417,471)	(3,838,118)
Additions to other property and equipment	(24,293)	(32,810)
Other assets	(767,381)	(485,774)
Net cash used by investing activities	(10,209,145)	(4,356,702)
Cash flows from financing activities:		
Issuance of warrants	100	-
Proceeds from short-term notes payable	1,260,276	-
Repayment of short-term notes payable	(1,389,234)	(1,966,650)
Proceeds from debt borrowings	-	1,799,071
Repayment of debt borrowings	(5,500,000)	-
Repayment of debt borrowings - related party	-	(82,117)
Settlement of commodity hedges recorded in purchase accounting	38,913	1,763,730
Net cash provided (used) by financing activities	(5,589,945)	1,514,034
Net increase (decrease) in cash and cash equivalents	(17,165,499)	15,897,489

Cash and cash equivalents - beginning of period		21,575,483		5,677,994
Cash and cash equivalents - end of period	$	4,409,984	$	21,575,483
Supplemental disclosures of cash flow information:				
Cash paid for income taxes	$	902,491	$	-
Cash paid for interest		10,537,405		3,306,907
Non-cash investing and financing activities:				
Accounts payable for oil and gas additions	$	181,933	$	2,796,041
Accrued liabilities for oil and gas additions		280,556		-
Revisions to asset retirement obligations		281,389		(374,081)
Accrued interest converted to long-term debt		30,811,843		-
Debt issuance costs from issuance of warrants		4,099,016		-

See notes to consolidated and combined financial statements.

Saratoga Resources, Inc.

NOTES TO THE CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

NOTE 1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

Saratoga Resources, Inc., is an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of natural gas and crude oil properties.

Our financial statements include the accounts of Saratoga Resources, Inc., a Texas corporation, and its subsidiaries. We proportionately consolidate our interests in oil and gas exploration and production ventures and partnerships in accordance with industry practice. All significant intercompany balances and transactions have been eliminated. Unless otherwise specified or the context otherwise requires, all references in these notes to Saratoga, , Company we, us or our are to Saratoga Resources, Inc., and its subsidiaries.

Accounting for Reorganization

On March 31, 2009, Saratoga and its subsidiaries, all of which are 100%-owned: Harvest Oil and Gas, LLC, The Harvest Group, LLC, Lobo Operating, Inc. and Lobo Resources, Inc. (collectively the Debtors), filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code. The Debtors operated under Chapter 11 protection from the filing date on March 31, 2009 until the effective date of the Debtors plan of reorganization (the Plan of Reorganization) and exit from Chapter 11 on May 14, 2010. The accompanying consolidated financial statements of Saratoga have been prepared in accordance with FASB ASC 852, *Reorganizations*.

The accompanying consolidated financial statements reflect the Company s exit from bankruptcy on the terms set out in its Plan of Reorganization, including (1) the reclassification of amounts previously classified as Liabilities Subject to Compromise (LSTC) to current liabilities and payment, in part, of such amounts as provided for in the Plan of Reorganization, (2) the reclassification of previously deferred interest expense as long term debt, and (3) the issuance of common stock and warrants pursuant to the Plan of Reorganization. See Note 3 Chapter 11 Reorganization and Note 5 Liabilities Subject to Compromise .

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of 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. Material estimates that are particularly susceptible to significant change in the near term include the determination of depreciation, depletion and amortization, plugging and abandonment liabilities, and the valuation of oil and gas property.

Reclassifications

Certain reclassifications have been made to prior years reported amounts in order to conform with the current year presentation. These reclassifications did not impact our net income, stockholders equity or cash flows.

Dependence on Oil and Gas Prices

As an independent oil and gas producer, our revenue, profitability and future rate of growth are substantially dependent on prevailing prices for natural gas and oil. Historically, the energy markets have been very volatile, and there can be no assurance that oil and gas prices will not be subject to wide fluctuations in the future. Prices for oil and gas declined materially in 2008 and early 2009. Any recurrence of such decline in oil or gas prices could have a material adverse effect on our financial position, results of operations, cash flows and access to capital and on the quantities of oil and gas reserves that we can economically produce.

Revenue Recognition

We recognize oil and gas revenue from interests in producing wells using the sales method. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where we have taken less than our share of production. Our net imbalance position at December 31, 2010, was immaterial.

Derivative Instruments

We account for our derivative activities by applying authoritative accounting and reporting guidance which requires that every derivative instrument be recorded on the balance sheet as either an asset or a liability measured at its fair value and that changes in the derivative s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Substantially all of the derivative instruments that we have utilized have been to manage the price risk attributable to our expected oil and gas production. We have elected not to designate price risk management activities as accounting hedges under the accounting guidance and, accordingly, account for them using the mark-to-market accounting method. Under this method, the changes in contract values are reported currently in earnings.

See Note 6, Commodity Derivative Instruments , for a more detailed discussion of our hedging activities.

Concentration of Credit Risk

Financial instruments that potentially subject the Company to a concentration of credit risk include cash, cash equivalents and any marketable securities. The Company had cash deposits of approximately $4.2 million in excess of FDIC insured limits at the period end. The Company has not experienced any losses on its deposits of cash and cash equivalents.

Major Customers

Sales of oil and gas production to each of Conoco, Shell and Chevron accounted for 11%, 68% and 16%, respectively of our consolidated revenues in 2010. We believe that the loss of any of these customers would not have a material adverse effect on us because alternative purchasers are readily available.

Cash and Cash Equivalents

For the purpose of the Statement of Cash Flows, we consider all highly liquid investments with a maturity of three months or less to be cash equivalents.

Accounts Receivable

Receivables are carried at original invoice amount. Uncollectible accounts receivable are charged directly against earnings when they are determined to be uncollectible. Use of this method does not result in a material difference from the valuation method required by generally accepted accounting principles. At December 31, 2010, no reserve for allowance for doubtful accounts was needed.

Oil and Gas Operations

Oil and gas exploration and development costs are accounted for using the successful efforts method of accounting.

Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for the classification of reserves as proved, the associated leasehold costs are reclassified to proved properties.

Oil and gas exploration costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or suspended, on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while we seek government or co-venture approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

Oil and gas development costs incurred to drill and equip development wells, including unsuccessful development wells, are capitalized.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Assets are grouped in accordance with the Extractive Industries - Oil and Gas Topic of the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC). The basis for grouping is a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Amortization rates are updated quarterly to reflect: 1) the addition of capital costs, 2) reserve revisions (upwards or downwards) and additions, 3) property acquisitions and/or property dispositions and 4) impairments.

When circumstances indicate that an asset may be impaired, Saratoga compares expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on Saratoga s estimate of future natural gas and crude oil prices, operating costs, anticipated production from proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate.

We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset.

Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and do not have a future economic benefit, are expensed. Liabilities for environmental expenditures are recorded on an undiscounted basis (unless acquired in a purchase business combination) when environmental assessments or cleanups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties, such as state reimbursement funds, are recorded as assets when their receipt is probable and estimable.

See Note 7 Oil and Gas Assets .

Depreciation of Other Property and Equipment

Furniture, fixtures, equipment, and other are depreciated using the straight-line method over the estimated useful lives of the assets. The estimated life of these assets ranges from three to five years.

Stock Based Compensation

In accordance with the provisions of the Stock Compensation Topic of the ASC (ASC Topic 718), Saratoga measures the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award.

Income Taxes

We account for income taxes under the provisions of the Income Taxes Topic of the ASC (ASC Topic 740). ASC Topic 740 requires the asset and liability approach for accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax basis (see Note 12 Income Taxes).

Net Income Per Share

Basic net income per share is computed on the basis of the weighted-average number of common shares outstanding during the periods. Diluted net income per share is computed based upon the weighted-average number of common shares plus the assumed issuance of common shares for all potentially dilutive securities (see Note 11 Common Stock).

Recently Issued Accounting Standards and Developments

In December 2008, the SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting* (ASC 2010-3), which amended the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, and added a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which was eliminated. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 are now required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning for financial statements for fiscal years ending on or after December 31, 2009. The Company adopted SEC Release No. 33-8995 effective December 31, 2009. The impact on the Company's operating results, financial position and cash flows has been recorded in the financial statements and additional disclosures were added to the accompanying notes to the consolidated financial statements for the Company's supplemental oil and gas disclosure. See *Supplemental Oil and Gas Information* for more details.

In January 2010, the Financial Accounting Standards Board (FASB) issued FASB Accounting Standards Update (ASU) No. 2010-03 *Oil and Gas Estimation and Disclosures* (ASU 2010-03). This update aligns the current oil and natural gas reserve estimation and disclosure requirements of the Extractive Industries Oil and Gas topic of the FASB Accounting Standards Codification (ASC Topic 932) with the changes required by the SEC final rule ASC 2010-3. As discussed above, ASU 2010-03 expands the disclosures required for equity method investments, revises the definition of oil- and natural gas-producing activities to include nontraditional resources in reserves unless not intended to be upgraded into synthetic oil or natural gas, amends the definition of proved oil and natural gas reserves to require 12-month average pricing in estimating reserves, amends and adds definitions in the Master Glossary that is used in estimating proved oil and natural gas quantities and provides guidance on geographic area with respect to disclosure of information about significant reserves. ASU 2010-03 must be applied prospectively as a change in accounting principle that is inseparable from a change in accounting estimate and is effective for entities with annual reporting periods ending on or after a change in accounting estimate and is effective for entities with annual reporting periods ending on or after December 31, 2009. The Company adopted ASU 2010-03 effective December 31, 2009. See *Supplemental Oil and Gas Information* for more details.

In January 2010, the FASB issued ASU No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06 did not impact the Company's operating results, financial position or cash flows, but did impact the Company's disclosures on fair value measurements. See Note 6, *"Fair Value Measurements."*

In April 2010, the FASB issued ASU No. 2010-12, *Accounting for Certain Tax Effects of the 2010 Health Care Reform Acts* (ASU 2010-12). This update clarifies questions surrounding the accounting implications of the different signing dates of the Health Care and Education Reconciliation Act (signed March 30, 2010) and the Patient Protection and Affordable Care Act (signed March 23, 2010). ASU 2010-12 states that the FASB and the Office of the Chief Accountant at the SEC would not be opposed to view the two Acts together for accounting purposes. The adoption of ASU 2010-12 did not impact the Company's operating results, financial position, cash flows or disclosures.

In December 2010, the FASB issued ASU No. 2010-28, *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts* (ASU 2010-28). This codification update modifies Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts and requires reporting units with such carrying amounts to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. ASU 2010-28 is effective for fiscal years and interim periods beginning after December 15, 2010 and early adoption is not permitted. The Company will adopt the provisions of this update in its Quarterly Report on Form 10-Q for the three months ended March 31, 2011. The Company is currently evaluating the impact that this adoption will have on its operating results, financial position, cash flows or disclosures but does not expect a material impact if any, as a result of the adoption.

In December 2010, the FASB issued ASU No. 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations* (ASU 2010-29). ASU 2010-29 requires a public entity who discloses comparative pro forma information for business combinations that occurred in the current reporting period to disclose revenue and earnings of the combined entity as though the business combination(s) occurred as of the beginning of the comparable prior annual period only. This update also expands the supplemental pro forma disclosures required to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. ASU 2010-29 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010 and early adoption is permitted. The Company will adopt the provisions of this update for any business combinations that occur after January 1, 2011.

NOTE 2. CORRECTION OF AN ERROR

During 2010, the Company discovered an error in third party billings for production handling services provided between 2006 and 2009. In October 2010, the Company received a one-time payment of $1.1 million in full satisfaction of underbilled production handling services.

The underbilling resulted in an understatement of revenue in 2006, 2007, 2008 and 2009. The Company assessed the materiality of this error on its financial statements for the years ended December 31, 2006, 2007, 2008 and 2009, in accordance with SEC Staff Accounting Bulletin (SAB) No. 99, Materiality and SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, or SAB 108, using both the roll-over method and iron-curtain method as defined in SAB 108. The Company concluded the effect of this error was not material to its financial statements for any prior period and, as such, those financial statements are not materially misstated. However, the error was deemed to be material to the current period, and as a result, the prior year financial statements presented in this Form 10-K were corrected to pursuant to SAB NO. 108.

The following tables show the changes reflected in the 2009 and 2008 financial statements:

Year ended December 31, 2009

	As reported	Adjustment	As restated
Oil and gas revenues	47,391,292	-	47,391,292
Other revenues	1,478,219	356,780	1,834,999
Total revenues	48,869,511	356,780	49,226,291
Operating income	97,678	356,780	454,458
Net loss before reorganization expenses and income taxes	(31,414,471)	356,780	(31,057,691)
Net loss before income taxes	(37,070,970)	356,780	(36,714,190)
Net loss	(27,351,145)	356,780	(26,994,365)
Net loss per share (basic and diluted)	(1.64)	0.02	(1.62)

Year ended December 31, 2009

	As reported	Adjustment	As restated
Net loss	(27,351,145)	356,780	(26,994,365)
Changes in accounts receivable	1,017,023	(356,780)	660,243
Net cash provided by operating activities	18,740,157	-	18,740,157

As of December 31, 2009

	As reported	Adjustment	As restated
Assets receivable	6,375,864	1,003,790	7,379,654
Total current assets	29,464,795	1,003,790	30,468,585
Total assets	172,834,751	1,003,790	173,838,541
Retained earnings	(13,237,914)	1,003,790	(12,234,124)
Total stockholders equity	6,666,590	1,003,790	7,670,380
Total liabilities and stockholders equity	172,834,751	1,003,790	173,838,541

As of December 31, 2008

	As reported	Adjustment	As restated
Retained earnings	14,113,231	647,009	14,760,240
Total stockholders' equity	33,439,767	647,009	34,086,776
Total liabilities and stockholders' equity	176,412,725	647,009	177,059,734

NOTE 3. CHAPTER 11 REORGANIZATION

On March 31, 2009, Saratoga and its subsidiaries, all of which are 100%-owned: Harvest Oil and Gas, LLC, The Harvest Group, LLC, Lobo Operating, Inc. and Lobo Resources, Inc. (collectively the Debtors), filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code.

On May 14, 2010, the Company satisfied all of the conditions set forth in its Plan of Reorganization, the Plan of Reorganization became effective and the Company exited from bankruptcy. The principal terms of the Plan of Reorganization were as follows:

.

the existing revolving credit agreement was amended as to maturity date and interest rate and claims under the revolving credit agreement were allowed in the amount of $23.5 million (including outstanding letters of credit), of which $5.5 million was paid on exit from bankruptcy; (See Note 4 – “Debt”)

.

the existing term credit agreement was amended and restated as to maturity and interest rate and claims under the term credit agreement were allowed in the amount of $127.5 million (including $30 million of accrued interest and reorganization costs capitalized and added to the principal balance of the term note); (See Note 4 – “Debt”)

.

all allowed claims of unsecured creditors and oil lien claim creditors are payable in full, with unsecured creditors receiving 75% in cash on exit from bankruptcy and the balance in quarterly installments over one year, and oil lien claim creditors receiving 80% in cash on exit from bankruptcy and the balance in quarterly installments over one year;

.

State lessor audit royalty claims were allowed 100% and are payable in monthly installments over twenty-four months;

.

amounts owing on notes payable to officers are payable in full, including compound accrued interest, in forty months;

.

a warrant to purchase 2,000,000 shares of our common stock was issued to the administrative agent for the revolving and term credit facilities; the warrant is exercisable at $0.01 per share and vested 111,111 shares on exit from bankruptcy and 111,111 shares per month thereafter; and

.

483,310 shares of common stock were issued pro rata among the oil lien claim creditors, other secured creditors and unsecured creditors.

Reorganization expense for the years ended 2010 and 2009 was $2.2 million and $5.7 million, respectively.

NOTE 4. DEBT

As of the indicated dates, debt consisted of the following:

	December 31, 2010	December 31, 2009
Senior secured credit facility due 2011	$ -	$ 12,528,878
Senior secured credit facility due 2012	7,840,871	-
20% subordinated secured note due 2011	-	96,282,422
11.25% subordinated secured note due 2012	123,359,338	-
	$ 131,200,209	$ 108,811,300

On May 14, 2010, the Company and Wayzata Investment Partners entered into an amendment to the prior revolving credit agreement and amended and restated the prior term credit agreement to reflect the terms of the Plan of Reorganization. See Note 3 Chapter 11 Reorganization. As so amended, the principal terms of the Amended Revolving Credit Agreement and the Amended and Restated Term Credit Agreement are as follows:

Amended Revolving Credit Agreement

Under the Amended Revolving Credit Agreement, the Company s revolving credit facility was revised to provide for total outstanding principal under the facility of $18.0 million, including $10.2 million in letters of credit and after payment of $5.5 million. No further borrowings can be made under the Amended Revolving Credit Agreement.

The Amended Revolving Credit Agreement provides for payments of interest only on a monthly basis at a floating rate of prime plus 2% with all amounts owing under the agreement being due and payable in full on April 30, 2012. The average interest rate paid during 2010 on amounts borrowed under the Amended Revolving Credit Agreement was 5.25%. Interest paid on amounts borrowed under the Amended Revolving Credit Agreement totaled $598,068 during 2010 and $0 of interest on amounts borrowed under that agreement was accrued and payable at December 31, 2010.

Amended and Restated Term Credit Agreement and Trouble Debt Restructuring

Under the Amended and Restated Term Credit Agreement, the Company s term credit facility was revised to reflect the total amount borrowed and owed thereunder of $127.5 million and to provide for accrual of interest at 11.25% per annum payable interest only on a monthly basis with all amounts owing under the agreement being due and payable in full on April 30, 2012. The principal amount owing under the term note includes interest expense and certain reorganization costs totaling $30.0 million that were capitalized as part of the aggregate principal amount payable on the term loan.

In evaluating the accounting for the debt restructuring under the Plan of Reorganization, management of the Company was required to make a determination as to whether the debt restructuring should be accounted for as a Troubled Debt Restructuring ("TDR") or as an extinguishment or modification of debt. The relevant accounting guidance required us to determine first whether the exchanges of debt instruments should be accounted for as a TDR. A TDR results when it is determined that a debtor is experiencing financial difficulties and the creditors grant a concession; otherwise, such exchanges should be accounted for as an extinguishment or modification of debt.

The Company then evaluated if the debt restructuring constituted a material modification, in which case the debt restructuring would be accounted for as an extinguishment of the original debt and the creation of new debt, resulting in the recognition of a gain or loss on the extinguishment of debt. If it was determined that the debt restructuring was a TDR, then there is no recognition of gain or loss on the extinguishment of debt, and the carrying amount of the debt is adjusted for any premium or discount that is amortized over the modification period.

Based on analysis performed and after the consideration of the applicable accounting guidance, management concluded that the debt restructuring was deemed to be a TDR. The debt restructuring was determined to be a TDR based on the creditors being deemed to have granted a concession since our effective borrowing rate of 13.93% on the restructured debt is less than the 22.15% effective borrowing rate of the old debt immediately prior to the restructuring. Accordingly, the effects of the restructuring were accounted for prospectively from the time of the restructuring, and the restructured debt has been recorded with premiums which reflect the carrying value of the old debt less the fair value of 2,000,000 warrants for common stock issued to the creditors.

NOTE 5. LIABILITIES SUBJECT TO COMPROMISE

FASB ASC 852, *Reorganizations* requires prepetition liabilities that are subject to compromise to be reported at the amounts expected to be allowed, even if they may be settled for lesser amounts. The amounts classified as liabilities subject to compromise were subject to future adjustments depending on Court actions, further developments with respect to disputed claims, determinations of the secured status of certain claims, the values of any collateral securing such claims, or other events.

Pursuant to the Plan of Reorganization, notes payable to our Chief Executive Officer and to our President, in the aggregate amount of $605,428 will bear compound interest at 10% per annum and are due and payable in full, with interest, in September 2013.

Liabilities subject to compromise consist of the following:

	December 31,			
	2010		2009	
Accounts payable	$	-	$	13,043,112
Revenue and severance tax payable		-		2,144,046
Accrued interest		-		2,871,856
Accrued liabilities		-		967,125
Notes payable related parties		-		605,428
Total liabilities subject to compromise	$	-	$	19,631,567

See Note 3 Chapter 11 Reorganization for a discussion of the payment of various classes of holders of liabilities subject to compromise.

NOTE 6. COMMODITY DERIVATIVE INSTRUMENTS

We periodically use derivative instruments in connection with anticipated crude oil and natural gas sales to mitigate the variability of cash flows associated with commodity price fluctuations. While the use of these derivative instruments limits the downside risk of adverse price movements, their use also may limit future revenues from favorable price movements.

During the year ended December 31, 2010, we recognized a realized gain of $261,501 due to pricing and a realized gain of $435,049 as a result of the liquidation of all of our derivative instruments by our secured lender. During the year ended December 31, 2009, we recognized a realized gain of $6,546,297 in the Statement of Operations and an unrecognized loss of $10,576,301 as the result of market-to-market valuations.

As of December 31, 2010, the Company had no natural gas or crude oil derivative instruments outstanding.

NOTE 7. OIL AND GAS ASSETS

Property and equipment consisted of the following at:

	December 31,			
		2010		2009
Oil and gas properties (proved):				
Gross oil and gas properties (proved)	$	170,870,775	$	160,709,425
Accumulated depreciation, depletion and amortization		(37,242,966)		(21,379,660)
Net oil and gas properties (proved)		133,627,809		139,329,765
Other property and equipment		561,572		537,280
Accumulated depreciation and amortization		(355,014)		(216,494)
Net other property and equipment		206,558		320,786
Net property and equipment	$	133,834,367	$	139,650,551

NOTE 8. ASSET RETIREMENT OBLIGATIONS

We account for plugging and abandonment costs in accordance with FASB Accounting Standards Codification 410-20, *Accounting for Asset Retirement Obligations.*

We maintain an escrow agreement that has been established for the purpose of assuring maintenance and administration of a performance bond which secures certain plugging and abandonment obligations assumed in the 2008 acquisition of Harvest Oil & Gas, LLC and The Harvest Group, LLC (the Predecessor Companies).

At December 31, 2010 and 2009, the amount of the escrow account totaled $2,533,349 and $2,065,968, respectively and shown as other assets.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations are as follows:

Balance at December 31, 2008	$ 9,124,717
Accretion expense	1,439,437
Additions	-
Revisions	(374,081)
Settlements	-
Balance at December 31, 2009	$ 10,190,073
Accretion expense	1,668,268
Additions	-
Revisions	281,389
Settlements	(153,655)
Balance at December 31, 2010	$ 11,986,075

NOTE 9. RELATED PARTY TRANSACTIONS

During the year ended December 31, 2008, our principal officers advanced funds, provided services and paid costs on our behalf. As of December 31, 2010, we owed Thomas Cooke, our Chairman, Chief Executive Officer and principal shareholder, $482,932 in principal and $84,678 in accrued interest, and owed Andy Clifford, our President, $122,500 in principal and $21,479 in accrued interest for their funding of acquisition expenses and deferred salary. The indebtedness to the principle shareholder bears interest at 10%. No payments of principal or interest were made on the notes during 2010. During 2009, we made payments of interest on the notes to Messrs. Cooke and Clifford in the amounts of $12,333 and $3,128, respectively.

NOTE 10. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

We have commitments under non-cancellable operating lease agreements for our office spaces located in Covington, Louisiana and Houston, Texas.

Rent expense with respect to our lease commitments for office space for the year ended December 31, 2010 and 2009 was $210,349 and $238,038, respectively.

We have certain plugging and abandonment, reclamation, restoration, and clean up liabilities and obligations related to our oil and gas properties. To secure these liabilities, we maintain $10,159,128 at December 31, 2010 in letters of credit. The letters of credit are secured by our amended revolving credit agreement.

At December 31, 2010, total minimum commitments from long-term non-cancelable operating leases, seismic purchase and other purchase obligations are as follows:

	Payments due by period				
	Total	**2011**	**2012 2013**	**2014 2015**	**Thereafter**
Debt [1]	$ 138,455,917	$ 2,673,045	$ 135,782,872	$ -	$ -
Debt related parties (includes current	605,428	-	605,428	-	-

portion)										
Operating leases		351,944		209,588		84,924		57,432		-
Capital leases		-		-		-		-		-
Asset retirement obligations		31,855,000		291,000		1,072,000		2,600,000		27,892,000
Total	$	171,268,289	$	3,173,633	$	137,545,224	$	2,657,432	$	27,892,000

(1)

Debt includes (a) amounts borrowed under our amended term credit facility, in the amount of $127.5 million; (b) amounts borrowed under our amended revolving credit facility, in the amount of $7.8 million; (c) amounts payable pursuant to our Plan of Reorganization to certain unsecured creditors and oil lien claim creditors, in the amount of $1.6 million; (d) amounts payable pursuant to our Plan of Reorganization to the Louisiana Department of Mineral Resources for underpaid royalties, in the amount of $1.3 million (includes $0.4 million in penalties); and (e) installment obligations incurred relating to the acquisition of a seismic license, in the amount of $0.2 million.

Contingencies

From time to time the Company may become involved in litigation in the ordinary course of business. As of December 31, 2010 the Company s management was not aware, and as of the date of this report is not aware, of any such litigation that could have a material adverse effect on its results of operations, cash flows or financial condition.

The Company, as an owner or lessee and operator of oil and gas properties, is subject to various federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. These laws and regulations may, among other things, impose liability on the lessee under an oil and gas lease for the cost of pollution clean-up resulting from operations and subject the lessee to liability for pollution damages. In some instances, the Company may be directed to suspend or cease operations in the affected area. The Company maintains insurance coverage, which it believes is customary in the industry, although the Company is not fully insured against all environmental risks. The Company is not aware of any environmental claims existing as of December 31, 2010, which have not been provided for, covered by insurance or otherwise have a material impact on its financial position or results of operations. There can be no assurance, however, that current regulatory requirements will not change, or past non-compliance with environmental laws will not be discovered on the Company s properties.

In December 2009, the Parish of Plaquemines, State of Louisiana, filed additional assessments against multiple oil and gas companies, including Saratoga, for allegedly underpaid ad valorem taxes. The amount alleged to be due by Saratoga for the years 2009 and 2010 is $1.3 million. We are presently contesting the additional tax assessments in an action styled Aviva America, Inc., The Harvest Group, LLC, Harvest Oil & Gas, LLC, Saratoga Resources, Inc., Lobo Operating, Inc. and Lobo Resources, Inc. v. Robert R. Gravolet, In His Capacity as Assessor for Plaquemines Parish, Louisiana in the 25th Judicial District Court of Louisiana and, as to certain issues relating to such claim, in an administrative proceeding before the Louisiana Tax Commission. We believe the additional assessment is in error and intend to vigorously defend this action.

NOTE 11. COMMON STOCK

Net Income per Common Share

A reconciliation of the components of basic and diluted net income per common share is presented in the tables below:

	For the Year Ended December 31,					
	2010			2009		
	Income (Loss)	**Weighted Average Common Shares Outstanding**	**Per Share**	**Income (Loss)**	**Weighted Average Common Shares Outstanding**	**Per Share**
Basic:						
Income (loss) attributable to common stock	$ (19,441,528)	16,996,166	$ (1.14)	$ (26,994,365)	16,687,561	$ (1.62)

Effective of Dilutive Securities:										
Stock options and other		-	-				-	-		
Diluted:										
Income (loss) attributable to common stock, including assumed conversions	$	(19,441,528)	16,996,166	$	(1.14)	$	(26,994,365)	16,687,561	$	(1.62)

Potentially dilutive securities excluded from the computation of weighted average diluted shares of common stock because the impact of these potentially dilutive securities were antidilutive totaled 4,148,016 and 1,165,516 for the year ended December 31, 2010 and 2009, respectively.

Equity Issuance

During the year ended December 31, 2009, we issued 12,500 shares of common stock for services of a director and 2,500 shares of common stock to a consultant for services. The grant-date value of these shares was approximately $3,600.

During the year ended December 31, 2009, 200,000 shares of restricted common stock were forfeited and cancelled. In addition, 536,000 shares of restricted stock vested during 2009.

During the year ended December 31, 2010, 96,000 shares of restricted stock vested.

The following table summarizes information about restricted share activity for the year ended December 31, 2010 as previously described:

	Number of Restricted Shares		Weighted Average Grant Date Fair Value per Share
Outstanding at December 31, 2008	832,000	$	2.55
Granted	-		-
Forfeited	(200,000)		2.55
Vested	(536,000)		2.55
Outstanding at December 31, 2009	96,000	$	2.55
Granted	-		-
Forfeited	-		-
Vested	(96,000)		2.55
Outstanding at December 31, 2010	-	$	-

Stock-Based Compensation

In January 2006, our Board of Directors adopted the Saratoga Resources, Inc. 2006 Employee and Consultant Stock Plan (the Stock Plan).

Pursuant to the Stock Plan, 1,200,000 shares of common stock were reserved for issuance to employees and consultants as compensation for past or future services or the attainment of goals. In October 2007, the Stock Plan was amended to increase the shares reserved thereunder to 2,525,000. As of December 31, 2010, 1,430,000 shares were available under this plan.

The Stock Plan is administered by the Board of Directors subject to the right of the Board of Directors to appoint a committee of the Board of Directors to administer the same.

Effective October 17, 2008, we adopted the Saratoga Resources, Inc. 2008 Long-term Incentive Plan (the 2008 Plan). The 2008 Plan reserves a total of 3,000,000 for issuance to eligible employees, officers, directors and other service providers pursuant to grants of options, restricted stock, performance stock and other equity based compensation arrangements. As of December 31, 2010, no awards had been made under the 2008 Plan.

During the year ended December 31, 2009, we issued 12,500 shares of common stock for services of consultants.

During the year ended December 31, 2009, stock options to purchase 75,000 shares of common stock, with a grant-date value of $13,386, were granted to directors. The options are exercisable at $0.36 per share for a term of ten years. The options fully vested immediately. The options were valued using the Black-Sholes model with the following assumptions: $0.36 quoted stock price; $0.36 exercise price; 341% volatility; 5 year estimated life; zero dividends; 1.92% discount rate.

Stock based compensation expense attributable to common shares and grants of options was $577,968 during the year ended December 31, 2009.

In April 2010, the Company s board of directors approved stock option grants to purchase an aggregate of 845,000 shares of common stock to the Company s directors and to various key employees, including an aggregate of 50,000 stock options granted to directors and 150,000 stock options granted to an officer of the Company. 330,000 of the options granted in April 2010 were forfeited during 2010. The grant date value of the aggregate 845,000 options was $2,535,000, which includes the grant date value of the 330,000 options forfeited of $990,000. The options are exercisable at $3.00 per share for a term of ten years. The options are subject to different vesting periods. The options were valued using the Black-Sholes model with the following assumptions: $3.00 quoted stock price; $3.00 exercise price; 352% volatility; 5 to 6 year estimated life; zero dividends; 2.61% discount rate.

In July 2010, the Company granted stock options to purchase 115,000 shares of common stock to employees, including 40,000 options granted to an officer. The options are exercisable at $1.53 per share for a term of ten years and vest ratably over three years. The grant date value of the options was $175,950. The options were valued using the Black-Scholes model with the following assumptions: $1.53 quoted stock price; $1.53 exercise price; 345% volatility; 5.8 year estimated life; zero dividends; and 2.12% discount rate.

In July 2010, the Company granted stock options to purchase 120,000 shares of common stock to employees, including 100,000 options granted to an officer. The options are exercisable at $1.71 per share for a term of ten years and vest ratably over three years. The grant date value of the options was $205,200, which includes the grand date value of 20,000 options forfeited of $34,200. The options were valued using the Black-Scholes model with the following assumptions: $1.71 quoted stock price; $1.71 exercise price; 344% volatility; 6 year estimated life; zero dividends; and 2.1% discount rate.

In July 2010, the Company granted stock options to purchase 202,500 shares of common stock to consultants. The options are exercisable at $1.71 per share for a term of five years. 2,500 of the options were granted to a consultant for investor relations and vested on the date of grant. 200,000 of the stock options were granted to a consultant for business development services of which 10,000 vested on grant date. The remaining 190,000 options vest as follows: (i) 2,000 options vest each month from August 2010 to December 2010; (ii) 80,000 options vest based on satisfaction of certain performance criteria, and (iii) 25,000 options vest on each of June 30, 2011, December 31, 2011, December 31, 2012 and December 31, 2013 provided that the consultant continues to provide services to the Company as of those dates. The grant date value of the options was $61,070. The options were valued using the Black-Scholes model with the following assumptions: $1.71 quoted stock price; $1.71 exercise price; 344% volatility; 2 to 3 year estimated life; zero dividends; and 0.98% discount rate.

In August 2010, the Company granted stock options to purchase 10,000 shares of common stock to a consultant. The options are exercisable at $1.39 per share for a term of five years and vest in full on February 28, 2011. The grant date value of the options was $13,800. The options were valued using the Black-Scholes model with the following assumptions: $1.39 quoted stock price; $1.39 exercise price; 340% volatility; 2.5 year estimated life; zero dividends; and 0.98% discount rate.

Stock based compensation expense attributable to common shares and grants of options was $2,570,145 during the year ended December 31, 2010. The unamortized amount of stock-based compensation that has not been recorded as of December 31, 2010 was $700,755.

The following table presents the options outstanding at December 31, 2010:

	Number of Shares	**Weighted Average**	**Weighted Average**	**Weighted Average**	**Aggregate Intrinsic**

	Underlying Options		Exercise Price per Share		Grant Date Fair Value per Share	Remaining Contractual Life (in Years)		Value (1)
Outstanding at December 31, 2008	-		-		-	-		-
Granted	75,000	$	0.36	$	0.18	8.2	$	141,750
Exercised	-		-		-	-		-
Forfeited	-		-		-	-		-
Outstanding at December 31, 2009	75,000	$	0.36	$	0.18	8.2	$	141,750
Granted	1,292,500		2.53		2.53	8.6		265,550
Exercised	-		-		-	-		-
Forfeited	(350,000)		1.64		2.93	-		-
Outstanding at December 31, 2010	1,017,500	$	2.24	$	2.23	8.3	$	407,300
Exercisable at December 31, 2010	552,500	$	2.49	$	2.46	8.2	$	204,350

(1)

The intrinsic value of an option is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the warrant. On December 31, 2010, the last reported sales price of our common stock on the OTCBB was $2.25 per share.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2010:

Options Outstanding and Exercisable			
Exercise Price	Number of Shares Underlying Warrants	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Life (in Years)
$ 0.36	75,000	$ 0.36	8.2
1.39	10,000	1.39	4.7
1.71	102,500	1.71	4.5
3.00	365,000	3.00	9.3
	552,500	$ 2.49	8.2

Warrants

In April 2010, the Company sold to a service provider, for a purchase price of $100, a warrant to purchase 40,000 shares of the Company s common stock. The grant date value of the warrants was $120,000 and recorded as legal expense. The warrants are exercisable at $3.00 per share for a term of five years. The warrants are vested immediately. The warrants were valued using the Black-Sholes model with the following assumptions: $3.00 quoted stock price; $3.00 exercise price; 352% volatility; 5 year estimated life; zero dividends; 2.61% discount rate.

In May 2010, pursuant to the Plan of Reorganization, the Company issued 2,000,000 warrants exercisable at $0.01 per share and subject to vesting over an eighteen month period. See Note 3 Chapter 11 Reorganization.

The following table presents the warrants outstanding at December 31, 2010:

	Number of Shares Underlying Warrants	Weighted Average Exercise Price per	Weighted Average Grant Date Fair	Weighted Average Remaining Contractual	Aggregate Intrinsic Value (1)

		Share	Value per Share	Life (in Years)	
Outstanding at December 31, 2008	1,085,516	$ 0.07	$ 1.96	2.5	$ 2,366,756
Granted	5,000	1.50	0.51	2.8	3,750
Exercised	-	-	-	-	-
Forfeited	-	-	-	-	-
Outstanding at December 31, 2009	1,090,516	$ 0.08	$ 1.99	2.5	$ 2,370,506
Granted	2,040,000	0.07	2.07	4.3	4,480,000
Exercised	-	-	-	-	-
Forfeited	-	-	-	-	-
Outstanding at December 31, 2010	3,130,516	$ 0.07	$ 2.03	3.7	$ 6,850,506
Exercisable at December 31, 2010	2,019,045	$ 0.11	$ 2.01	3.3	$ 4,361,617

(1)

The intrinsic value of a warrant is the amount by which the market value of our common stock at the indicated date, or at the time of exercise, exceeds the exercise price of the warrant. On December 31, 2010, the last reported sales price of our common stock on the OTCBB was $2.25 per share.

The following table summarizes information about stock warrants outstanding and exercisable at December 31, 2010:

Warrants Outstanding and Exercisable

Exercise Price	Number of Shares Underlying Warrants	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Life (in Years)
$ 0.01	1,694,405	$ 0.01	3.5
0.17	30,000	0.17	2.4
0.25	250,000	0.25	2.4
1.50	5,000	1.50	2.8
3.00	40,000	3.00	4.3
	2,019,405	$ 0.11	3.3

NOTE 12. INCOME TAXES

The Company is subject to income tax in the United States. Current tax obligations associated with our provision for income taxes are reflected in the accompanying Balance Sheet as component of Accrued liabilities and the deferred tax obligations are reflected in Deferred income taxes .

Our effective tax rates were different than our federal statutory tax rate due to state income taxes associated with income from various locations in which we have operations. Estimates of future taxable income can be significantly affected by changes in oil and natural gas prices, the timing, amount, and location of future production and future operating expenses and capital costs.

Our provision (benefit) for income taxes at December 31, 2010 and 2009 consisted of the following:

	2010	2009
Current:		
Federal	$ -	$ -
State	285,838	212,520
	285,838	212,520

Deferred:				
Federal		-		(8,727,541)
State		-		(1,204,804)
		-		(9,932,345)
Total tax provision (benefit)	$	285,838	$	(9,719,825)

The U.S. federal statutory income tax rate is reconciled to the effective rate at December 31, 2010 and 2009 as follows:

	2010	**2009**
Income tax expense at U.S. federal statutory rate	35.0%	35.0%
Valuation allowance	(31.0)%	(11.0)%
State and local income taxes, net of federal income tax benefit	3.3%	3.3%
Permanent differences	(6.9)%	(4.6)%
Other differences	(1.9)%	3.5%
Provision for income taxes	(1.5)%	26.2%

The components of the net deferred tax assets (liabilities) at December 31, 2010 and 2009 are as follows:

	2010	2009
Deferred tax asset		
Net operating loss	$ 10,236,257	$ 9,594,084
Stock-based compensation	1,557,763	592,019
Debt issuance cost (amortization)	456,484	360,936
Depreciation and amortization	18,582	-
Other	-	8,455
Capital loss carryover	103,752	103,752
Charitable contributions	7,048	5,116
Total deferred tax assets	12,379,886	10,664,362
Deferred tax liability		
Depletion on oil and gas properties	2,386,333	6,438,650
Derivatives	-	166,407
Total deferred tax liabilities	2,386,333	6,605,057
Less: valuation allowance	(9,993,553)	(4,059,305)
Deferred tax asset (liability)	$ -	$ -

At December 31, 2010, we had $26.8 million of federal net operating loss, or NOL, carryforwards; the federal NOL carryforwards have expiration dates through the year 2030.

At this time, we have established a valuation allowance for uncertainties in realizing the benefit of tax loss and credit carryforwards, and other deferred tax assets; while we expect to realize the deferred tax assets at December 31, 2010, changes in estimates of future taxable income or in tax laws may alter this expectation.

NOTE 13. FAIR VALUE MEASUREMENTS

Certain of our financial and nonfinancial assets and liabilities are reported at fair value in the accompanying balance sheets. Effective January 1, 2008, we adopted the provisions of SFAS No. 157 (ASC 820) for financial assets and liabilities. ASC 820 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, ASC 820 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. ASC 820 requires that an entity give consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value. In accordance with FSP 157-2, we have not applied the provisions of ASC 820 to our asset retirement obligations.

F-21

The following table provides fair value measurement information within the hierarchy for our financial assets and liabilities:

	Fair Value Measurement Classification			
	Quoted Prices in Active Markets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
As of December 31, 2009				
Assets (liabilities):				
Oil and gas derivative option contracts	$ -	$ (616,770)	$ -	$ (616,770)
Oil and gas derivative swap contracts	-	1,051,819	-	1,051,819
Total	$ -	$ 435,049	$ -	$ 435,049
As of December 31, 2010				
Assets (liabilities):				
Oil and gas derivative option contracts	$ -	$ -	$ -	$ -
Oil and gas derivative swap contracts	-	-	-	-
Total	$ -	$ -	$ -	$ -

The estimated fair value of crude oil and natural options and price swaps contracts was based upon forward commodity price curves based on quoted market prices.

NOTE 14. SUPPLEMENTAL OIL AND GAS DISCLOSURES - UNAUDITED

Proved Oil and Gas Reserves

Proved oil and gas reserves were estimated by independent petroleum engineers. The reserves were based on the following assumptions:

.

Future revenues were based on year-end oil and gas prices. Future price changes were included only to the extent provided by existing contractual agreements.

.

Production and development costs were computed using year-end costs assuming no change in present economic conditions.

.

Future net cash flows were discounted at an annual rate of 10%.

Reserve estimates are inherently imprecise and these estimates are expected to change as future information becomes available.

The following summarizes our estimated total net proved reserves for the years in the three-year period ended December 31, 2010:

	Gas (Mcf)	Oil (Bbls)	Boe
For the year ended December 31, 2008			
Beginning of year	44,842,000	3,749,000	11,222,667
Acquisition of reserves	-	-	-
Discoveries	2,875,600	482,000	961,267
Extensions	-	-	-
Improved recovery	-	-	-
Revisions	3,521,400	856,000	1,442,900
Production	(1,612,000)	(572,000)	(840,667)
End of year	49,627,000	4,515,000	12,786,167
Proved developed reserves			
Beginning of year	11,064,000	3,308,000	5,152,000
End of year	13,695,200	3,172,600	5,455,133
For the year ended December 31, 2009			
Beginning of year	49,627,000	4,515,000	12,786,167
Acquisition of reserves	-	-	-
Discoveries	-	-	-
Extensions	-	-	-
Improved recovery	-	-	-
Revisions	14,735,500	3,690,000	6,145,917
Production	(2,114,600)	(626,900)	(979,333)
End of year	62,247,900	7,578,100	17,952,751
Proved developed reserves			
Beginning of year	13,695,200	3,172,600	5,455,133
End of year	9,387,400	2,984,800	4,549,367
For the year ended December 31, 2010			
Beginning of year	62,247,900	7,578,100	17,952,751
Acquisition of reserves	887,679	252,047	399,994
Discoveries	-	-	-
Extensions	-	-	-
Improved recovery	-	-	-
Revisions	(377,179)	598,253	535,390
Production	(1,882,800)	(550,000)	(863,800)
End of year	60,875,600	7,878,400	18,024,335
Proved developed reserves			
Beginning of year	9,387,400	2,984,800	4,549,367
End of year	5,112,400	2,656,600	3,508,667

The Company has recognized positive revisions in each of the years ended December 31, 2010, 2009 and 2008. The positive revisions of 535,390 Boe in 2010 and 6,145,917 Boe in 2009 were due to positive price revisions. The 2008 positive revisions were due to improved performance.

In 2010, the Company acquired 3 state leases with proved undeveloped reserves of 399,994 Boe.

Capitalized costs for our oil and gas producing activities consisted of the following at the end of each of the years in the three-year period ended December 31, 2009:

	2010	2009	2008
Proved properties	$ 170,808,035	$ 160,709,425	$ 154,449,346
Unproved properties	62,740	-	-
	170,870,775	160,709,425	154,449,346
Accumulated depreciation, depletion and amortization	(37,242,966)	(21,379,660)	(6,939,036)
Net capitalized costs	$ 133,627,809	$ 139,329,765	$ 147,510,310

Costs incurred for oil and gas property acquisitions, exploration and development for each of the years in the three-year period ended December 31, 2009 are as follows:

	2010	2009	2008
Acquisitions of properties:			
Proved	$ 99,015	$ -	$ 140,071,085
Unproved	44,261	-	-
Exploration	1,590,029	1,145,724	-
Development	9,736,684	6,634,160	12,236,990
	$ 11,469,989	$ 7,779,884	$ 152,308,075

The following table sets forth the consolidated and combined results of operations for the year ended December 31, 2010, 2009 and 2008.

	For the Year Ended December 31, 2010	For the Year Ended December 31, 2009	July 15, 2008 December 31, 2008	January 1, 2008 July 14, 2008 (Predecessor)	For the Year Ended December 31, 2008 (Combined)
Oil and gas sales	$ 52,734,207	$ 47,391,292	$ 22,423,746	$ 46,475,559	$ 68,899,305
Production costs	(14,106,320)	(17,760,824)	(9,639,122)	(17,356,190)	(26,995,312)
Workover expense	(2,154,482)	(2,112,090)	(1,027,547)	-	(1,027,547)
Exploration expense	(1,590,029)	(1,145,724)	-	-	-
Depreciation, depletion and amortization	(15,863,307)	(14,440,621)	(5,245,596)	(2,507,086)	(7,752,682)

Impairments	-	-	(1,693,440)	-	(1,693,440)
Severance taxes	(5,214,677)	(5,672,312)	(2,510,548)	(5,609,040)	(8,119,588)
Income before income taxes	13,805,392	6,259,721	2,307,493	21,003,243	23,310,736
Income tax provision*	285,838	1,640,047	846,812	7,707,848	8,554,660
Results of operations for oil and gas producing activities (excluding corporate overhead and financing costs)	$ 13,519,554	$ 4,619,674	$ 1,460,681	$ 13,295,395	$ 14,756,076

----

*Income tax provision for predecessor represents pro forma data using our effective tax rate. The acquisition of the Harvest Companies occurred on July 14, 2008. The Harvest Companies were limited liability companies and did not have an income tax provision.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information was developed utilizing procedures prescribed by Accounting Standards Codification 932-235 (ASC 932-235), *Disclosures about Oil and Gas Producing Activities.* The information is based on estimates prepared by independent petroleum engineers. The standardized measure of discounted future net cash flows should not be viewed as representative of the current value of our proved oil and gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating us or our performance.

In reviewing the information that follows, we believe that the following factors should be taken into account:

future costs and sales prices will probably differ from those required to be used in these calculations;

actual production rates for future periods may vary significantly from the rates assumed in the calculations;

a 10% discount rate may not be reasonable relative to risk inherent in realizing future net oil and gas revenues; and

future net revenues may be subject to different rates of income taxation.

Under the standardized measure, future cash inflows were estimated by applying year-end oil and gas prices applicable to our reserves to the estimated future production of year-end proved reserves. Future cash inflows do not reflect the impact of open hedge positions. Future cash inflows were reduced by estimated future development, abandonment and production costs based on year-end costs in order to arrive at net cash flows before tax. Future income tax expense has been computed by applying year-end statutory tax rates to aggregate future pre-tax net cash flows reduced by the tax basis of the properties involved and tax carryforwards. Use of a 10% discount rate and year-end prices and costs are required by ASC 932-235.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

The standardized measure of discounted future net cash flows from our estimated proved oil and gas reserves is as follows:

(dollars in thousands)	**2010**	**2009**	**2008**
Future cash inflows	$ 934,061	$ 696,034	$ 402,022
Future production costs	(209,593)	(185,139)	(79,702)
Future development costs	(239,510)	(165,960)	(102,416)
Future net cash flows before income taxes	484,958	344,935	219,904
Future income tax expense	(130,490)	(121,711)	(76,967)
Future net cash flows before 10% discount	354,468	223,224	142,937
10% annual discount for estimating timing of cash flows	(118,811)	(77,638)	(44,943)
Standardized measure of discounted future net cash flows	$ 235,657	$ 145,586	$ 97,994

Set forth in the table below is a summary of the changes in the standardized measure of discounted future net cash flows for our proved oil and gas reserves:

(dollars in thousands)	**2010**	**2009**	**2008**
Beginning of year	$ 145,586	$ 97,994	$ 300,067
Sales of oil and gas produced, net of production costs	(31,270)	(20,705)	(36,956)
Net change in prices and production costs	135,389	29,321	(190,296)
Extension, discoveries, and improved recovery, less related costs	-	-	107,522
Development costs incurred during the year	-	6,634	12,942
Net change in estimated future development costs	(49,840)	(47,115)	(30,937)
Revisions of previous quantity estimates	13,943	90,937	(25,355)
Net change from acquisitions of minerals in place	3,689	-	-
Net change in income taxes	(1,919)	(27,907)	(50,485)
Accretion of discount	22,398	14,695	2,530
Changes in timing and other	(2,319)	1,732	8,962
End of year	$ 235,657	$ 145,586	$ 97,994