SARATOGA RESOURCES INC /TX
Form 10-K
March 27, 2012

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, 2011

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
Common Stock, $0.001 par value	NYSE AMEX

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

None
(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 ý 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. ¨

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, 2011, based on the closing sales price of the registrant s common stock on that date, was approximately $39,101,000. 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 21, 2012 was 27,250,090.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s Proxy Statement for its 2012 Annual Meeting are incorporated by reference into Part III of this Report.

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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.

anticline An arch-shaped fold in rock in which rock layers are upwardly convex. The oldest rock layers form the core of the fold, and outward from the core progressively younger rocks occur.

Bbl One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil and other liquid hydrocarbons.

Bcf One 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.

Boepd Boe per day.

Bopd Bbls per day.

Btu One British thermal unit.

completion The installation of permanent equipment for the production of oil or natural gas, 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 an oil and gas 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 An exploratory or development 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 oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas 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 a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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.

held by production or *HBP* A provision in an oil and gas lease that perpetuates a company s right to operate a property or concession as long as the property or concession produces a minimum paying quantity of oil or gas.

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Henry Hub The pricing point for natural gas futures contracts traded on the NYMEX.

HLS Heavy Louisiana Sweet crude oil, being a high quality low-sulfur content premium crude oil.

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.

LLS Light Louisiana Sweet crude oil, being a high quality low-sulfur content premium crude oil.

MBbl One thousand barrels of 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.

MBoepd 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 per day.

Mcf One thousand cubic feet of natural gas.

Mcfpd Mcf per day.

MMBbl One million barrels of 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 One million British Thermal Units.

MMcf One million cubic feet of natural gas.

net acre Fractional ownership working interest multiplied by gross acres. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

net revenue interest A share of production after all burdens, such as royalty and overriding royalty, have been deducted from the working interest. It is the percentage of production that each party actually receives.

net wells The sum of our fractional interests owned in gross wells.

NGLs Natural gas liquids.

NYMEX The New York Mercantile Exchange.

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.

PDP Proved developed producing.

PDNP Proved developed nonproducing.

plugback To shut off lower formation in a well bore.

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 many 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.

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 After the initial completion of a well, the action and techniques of reentering the well and redoing or repairing the original completion to restore the well s productivity.

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

reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and 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 To close valves on a well so that it stops producing; said of a well on which the valves are closed.

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.

stratigraphic trap A variety of sealed geologic container capable of retaining hydrocarbons, formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

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

through-tubing Pertaining to a range of products, services and techniques designed to be run through, or conducted within, the production tubing of an oil or gas well. The term implies an ability to operate within restricted-diameter tubulars and is often associated with live-well intervention since the tubing is in place.

trap A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate.

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.

workover The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

WTI West Texas Intermediate crude oil, being light, sweet crude oil with high API gravity and low sulfur content used as a benchmark for U.S. crude oil refining and trading.

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

We are an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of crude oil and natural gas properties. Our properties are located exclusively in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana. None of our current properties or operations are in the Gulf of Mexico or subject to oversight of the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). Our properties span 12 fields which are characterized by over 30 years of development drilling and production history, including Grand Bay field which has over 70 years of production history and over 250 MMBoe produced to date, yet remains virtually unexplored at depths greater than 13,000 feet. Our properties, the majority of which were acquired in July 2008, cover an estimated 32,185 gross/net acres and substantially all are held by production (HBP) without near-term lease expirations. Most of our properties offer multiple stacked reservoir objectives with substantial behind pipe potential. We continually seek to enhance our acreage position through leasing and evaluation of opportunistic acquisitions both within the transition zone and beyond.

As of December 31, 2011, our total proved reserves were 19.0 MMBoe, consisting of 8.0 MMBbls of oil and 66.0 Bcf of natural gas. The PV-10 of our proved reserves at December 31, 2011 was $464 million, based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $465 million. Additionally, we had probable reserves of 12.9 MMBoe, consisting of 4.0 MMBbls of oil and 53.2 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities.

During 2011, we added 1,890 MBoe of proved reserves and produced 946 MBoe, of which 64% was oil. As of December 31, 2011, our development opportunities included 55 proved behind pipe and shut-in opportunities in 8 fields, 86 proved undeveloped opportunities within 24 proposed wells in 5 fields and 34 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2011, we had 29 probable undeveloped opportunities, 11 possible behind pipe and shut-in development opportunities and 79 possible undeveloped opportunities. During the year ended December 31, 2011, we completed two development wells, nine recompletions and 25 workovers.

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 Management s Discussion and Analysis of Financial Condition and Results of Operation Chapter 11 Reorganization. As a result of declaring bankruptcy and the absence of availability under our credit facilities, we operated in a liquidity constrained environment from early 2009 through March 2011.

During the year ended December 31, 2011, we raised approximately $34.8 million of equity and $127.5 million of debt financing and retired our prior credit facilities which were scheduled to mature in April 2012.

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

Our Strengths

High-Quality Resource Base. Our assets are located in shallow waters on parish and state leases of south Louisiana in fields that are characterized by over 30 years of development drilling and production history. These assets are in close proximity to several other fields operated by leading industry companies such as Apache Corporation, Energy XXI (Bermuda) Limited, Hilcorp Energy Company, McMoRan Exploration Co. and Swift Energy Company. We believe the quality and location of our properties reduce our development risk and promote operating efficiencies which help to reduce our lifting costs. Additionally, the oil produced by our assets currently commands a premium to WTI crude oil pricing. We also believe that our reserve base has significant undeveloped and exploratory drilling opportunities, which are relatively low risk.

Geographically Focused Assets Without Exposure to Deep Water Operating Risks or BOEMRE Regulation. Our proved reserves are primarily located in the shallow waters of the Grand Bay Field, Vermilion 16 Field and 10 other established fields on state and parish leases of south Louisiana. This focused asset base allows us to leverage our technical knowledge of the geological features and operating dynamics within this region. Our geographic focus also enables us to establish economies of scale in both drilling and production operations, allowing us to manage a greater amount of acreage and minimize the marginal costs associated with development activities. Because our operations are exclusively in shallow state waters, we are not currently subject to the regulations of the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) applicable to federal leases and are not exposed to the extreme risk associated with deep water operations. In addition, we are able to avoid the long lead times to first production and ultra-high costs associated with deep water development.

Extensive Workover and Drilling Inventory. We control approximately 32,185 gross acres that are largely HBP. Approximately 88% of our proved reserves are classified as proved developed nonproducing and proved undeveloped reserves. We believe our properties hold substantial additional behind pipe reserves beyond the amounts quantified in the proved reserves category and provide us with a significant number of exploration prospects. As of December 31, 2011, we had identified 55 proved behind pipe and shut-in development opportunities in 8 fields, 86 proved undeveloped opportunities within 24 proposed wells in 5 fields, 34 probable behind pipe and shut-in development opportunities, 29 probable undeveloped opportunities, 11 possible behind pipe and shut-in development opportunities and 79 possible undeveloped opportunities.

High Net Revenue Interests and Operational Control. We own an average net revenue interest in our properties of approximately 75%, which enhances our returns by reducing royalty payments and provides us flexibility in negotiating potential farm-outs, joint ventures, and other opportunities. Additionally, we own an average working interest of approximately 100% in our properties and operate 100% of the wells that comprise our PV-10 as of December 31, 2011. As an operator, we can more efficiently manage our operating costs, capital expenditures and the timing and method of development of our properties. Our significant operational control and expertise in the area should allow us to operate with a lower cost structure and maximize returns on capital employed.

Control of Infrastructure and Third-Party Processing Revenues. Our extensive infrastructure assets include six production platforms and over 100 miles of pipeline, mostly within the Main Pass and Breton Sound areas. Our infrastructure assets enhance our ability to expand our existing resource base through joint ventures with, and acquisitions of, neighboring producing properties and to generate revenues from third-party handling and processing. We currently receive processing revenues from third parties at the Grand Bay, Main Pass 52 and Vermilion 16 Fields.

Experienced Management Team. Our directors and executive officers have over 200 combined years of industry experience and a proven track record of successfully leading independent oil and natural gas companies. In addition, our management team has extensive major oil company operational expertise with particular emphasis on cost-control and reservoir management.

Our Strategy

We intend to use our competitive strengths to increase our reserves, production and cash flow. The following are key elements of our strategy:

Capitalize on Added Liquidity to Expand and Accelerate Development. From early 2009 through March 2011, our development strategy was carried out at a curtailed level as a result of our bankruptcy and absence of borrowing capacity under our credit facilities. This decreased level of spending suppressed our reserve growth, production and cash flow in 2009 and 2010, relative to the substantial number of low risk development opportunities already present in our proved reserve base. Since April 1, 2011, we have raised approximately $34.7 million of new equity financing and $127.5 million of new debt financing and retired $7.7 million of debt and $10.2 million of letter of credit obligations. As a result of this added liquidity, we have significantly expanded our capital spending from the approximately $17.0 million we spent in 2009 and 2010 combined to $25.9 million in 2011. We intend to add a new revolving credit facility during 2012 to provide us with additional liquidity. In the short term, we plan to deploy our capital to exploit our inventory of workover, recompletion, behind pipe and shut-in projects and development wells, as further described below. Upon completion of those projects, we intend to strategically develop our remaining inventory of prospects.

Grow Through Exploitation, Development and Exploration of Our Properties. We believe that our extensive HBP acreage position will allow us to grow organically through lower-risk development drilling and recompletion work. 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 offer multiple stacked reservoir objectives with substantial behind pipe potential. We intend to focus our efforts on exploiting our inventory of opportunities with a view to growing our production through a combination of field optimization efforts, including infrastructure upgrades, and conversion of PDNP and proved undeveloped reserves to PDP. In order to enhance our organic growth initiatives, we have made significant investments in, and will continue to invest in, our infrastructure to support increased handling capacity and create operating efficiencies to lower handling and other operating costs.

Participation in Ultra-Deep Shelf Prospects. Our current acreage position includes all rights at all depths and, within our acreage, we have identified a number of shallow water ultra-deep shelf prospects (depths in excess of 20,000 feet and water depths of less than 20 feet). We intend to partner with larger operators with ultra-deep drilling experience to explore one or more of our ultra-deep prospects in the Grand Bay and Vermilion 16 fields. To that end, we have entered into joint venture negotiations with McMoRan Exploration Company regarding the formation of a joint venture to explore ultra-deep prospects.

Actively Manage the Risks and Rewards of Our Drilling Program. We operate 100% of the wells that comprise our proved reserves as of December 31, 2011, and we own net revenue interests in our properties that average approximately 75% 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 production marketing. In addition, our high net revenue interests enhance our returns from each successful well we drill by generating a higher percentage of cash flow. We believe our high net revenue interests provide us with a unique opportunity to retain a substantial economic interest in riskier 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, 2011, we either owned or held licenses for 3-D seismic data covering over approximately 500 square miles over all of our properties. 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.

We have conducted and will continue to complete full field studies over all of our properties. Such field studies include an exhaustive review and integration of well data, wellbore utilization analysis, incorporation of 3-D seismic interpretation results and detailed geological mapping of each sand.

Pursue Opportunistic Acquisitions. We are an opportunity driven company and, to that end, evaluate potential acquisitions that are compatible with and enhance our growth objectives. We continually review opportunities to acquire producing properties, leasehold acreage and drilling prospects. When identifying acquisition candidates, we focus primarily on underdeveloped assets with significant growth potential that we believe will allow us to enhance and exploit properties without assuming significant geologic, exploration or integration risk. In particular, we target lease acreage and acquisition of mature producing assets adjacent to our existing acreage and infrastructure where we have available data indicating the presence of undepleted reserves. We believe these areas will provide us with an inventory of low-risk recompletion and extension opportunities in our geographic area of expertise.

We regularly review unleased state acreage and engage in discussions with potential sellers regarding acquisition opportunities. Where opportunities arise that can be funded by our cash flow and existing resources, particularly leasing activity, we may pursue acquisitions that can be completed in a relatively short period of time. Larger acquisitions, particularly acquisitions of producing properties, are likely to involve a substantial period of time and an involved process, including securing of financing arrangements on our part and there can be no assurance that we will be able to secure necessary financing to carry out an acquisition even if we are successful in identifying favorable acquisition opportunities and negotiating acceptable terms. During 2011, we increased our working interest in Grand Bay field through a negotiated re-assignment of a farmout with Clayton Williams Energy, Inc.

Properties

The following table describes our properties and production profile at December 31, 2011:

Property	Barrels of Oil Equivalent (MBoe)	% Oil	PV-10[1] (in thousands)	Net Acreage (estimated)	Net Revenue Interest %	Net Producing Wells	Reserve Life Index[2] (Years)
Grand Bay	6,328	70%	$ 194,091	17,270	62-79%	59	17.5
Vermilion 16	8,728	20%	$ 168,385	4,095	77-83%	1	*
Main Pass 46	1,756	28%	$ 35,024	1,662	64-78%	5	5.2
Other	2,157	60%	$ 66,814	9,158	70-88%	36	6.1
All Properties	18,969	42%	$ 464,314	32,185	62-88%	101	17.7

*

Not meaningful

(1)

PV-10 is a non-GAAP financial measure as defined by the SEC. Based on unweighted average benchmark prices as of the first of each month during 2011 of $96.19 per Bbl and $4.113 per MMBtu and before future income taxes. The average realized price after applying differential to unweighted average benchmark prices was $106.51 per Bbl and $5.13 per Mcf.

(2)

Calculated by dividing total net proved reserves by current net production for December 2011.

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 in a protected in-bay environment on parish and state leases on the east side of the Mississippi River. Gulf Oil Corp. discovered the field in 1938. We are the operator of all of the Grand Bay with 100% working interest and an average 79% net revenue interest. Our leases in the Grand Bay Field, which are all HBP, cover an estimated 17,270 gross and net acres.

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.

This field has produced oil and gas from over 65 different sand formations located at depths between approximately 1,600 and 13,500 feet. Our field holdings include approximately 59 active wellbores, 44 proved developed nonproducing opportunities and 64 proved undeveloped opportunities in 14 proposed drilling locations within the field. There are also 26 probable developed nonproducing, 19 probable undeveloped opportunities in 14 proposed drilling locations, 11 possible developed nonproducing and 51 possible undeveloped opportunities in 14 proposed drilling locations within the field. We have undertaken a comprehensive full field study approach at Grand Bay Field that is still ongoing. We are continuing to evaluate the shallow Pliocene gas potential above 5,000 feet as well as deeper oil and gas potential in the Tex W, Big Hum, Cris I, Lower Tertiary and Cretaceous formations below 13,500 feet. We own a license to 90 square miles of proprietary 3-D seismic data relating to the Grand Bay Field, which was originally acquired by Greenhill in 1994 and reprocessed by Saratoga in 2008. We expect to use 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-content 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 in a 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. We are the operator with a 100% working interest and a net revenue interest ranging from 75% to 83%. The seven existing state leases cover an estimated 4,095 gross/net acres, of which 3,573 net acres are HBP.

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 performed in order to identify unswept hydrocarbons within existing wellbores. There are five wellbores associated with this field and eight proved undeveloped drilling locations within the field. NuTech Energy Alliance completed a full field study of the Vermilion 16 Field in early 2010. We licensed 25 square miles of 3D seismic data in 2008, which we expect to use to better locate proposed development wells.

Facilities include a central platform and the five wellbores associated with the field.

During the fourth quarter of 2011, we entered into joint venture discussions with McMoRan Exploration Company to target exploration of ultra-deep prospects (below approximately 20,000 feet) in Vermilion 16. Joint venture discussions with McMoRan were continuing as of late-March 2012.

Main Pass 46 Field. The Main Pass 46 Field is located in the transitional coastline in a protected in-bay environment on state leases offshore Plaquemines Parish, approximately 80 miles south-southeast of New Orleans, Louisiana. The field is situated in approximately six feet of water, immediately north of Grand Bay Field. We are the operator with a 100% working interest and a net revenue interest ranging from 64% to 78%. The four existing state leases cover an estimated 1,663 gross/net acres and are all HBP.

The field is a faulted anticlinal structure with outlying stratigraphic traps. There are multiple stacked reservoirs 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 platform and the 5 active wellbores associated with the field. All of the 11 proved undeveloped opportunities in 3 proposed new wellbores are located within Grand Bay State Lease 195.

Other Fields. We hold interests in nine other fields, all of which are located in shallow waters on state leases in Plaquemines, St. Bernard and St. Mary parishes of southern Louisiana, with working interests ranging from 40% to 100%. Our net revenue interests in these fields range from 31% to 88%, except for Breton Sound 31 Field, where we have a 36% net profit interest, and the Main Pass 47 Field, where we have a 7.5% overriding royalty interest in one producing well. The leases, which are mostly HBP, 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 significant infrastructure assets that are used to service our properties and third-party customers, including over 100 miles of pipeline connecting several of the fields as well as outlying wellheads. There are six platform facilities plus 89 active producing wellbores associated with these fields, including ten saltwater disposal wells. Facilities at the Grand Bay Field include four tank batteries, a compressor station, various flowlines and a bunk house. In addition to serving our wells and improving field economics, we generate processing and production handling revenues from third-party customers including McMoRan Oil and Gas, LLC and Martin-Marks Minerals, LLC. In 2011, those revenues totaled approximately $0.7 million.

Oil and Natural Gas Reserves

Reserve Estimates

SEC Case. The following tables sets forth, as of December 31, 2011, 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 (MBbls)**	**Natural Gas (MMcf)**	**Total[2]** (MBoe)
Proved			
Developed			
Producing	1,504	4,766	2,298
Shut-in	66	781	196
Behind Pipe	1,011	4,554	1,770
Total Proved Developed	2,581	10,101	4,264
Undeveloped	5,394	55,861	14,705
Total Proved	7,975	65,962	18,969
Probable[3]			
Developed	1,115	5,148	1,973
Undeveloped	2,940	48,100	10,957
Possible[3]			
Developed and Undeveloped	13,656	120,210	33,691
PV-10[1] (in thousands)			$ 464,314
Standardized Measure[4] (in thousands)			$ 330,884

(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, 2011. 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, 2011 which were $96.19 per Bbl and $4.113 per MMBtu. The prices utilized for purposes of estimating our proved reserves were $106.51 per Bbl and $5.13 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 2011 12-month average prices reflected in our reported reserve estimates and the 10-year average future NYMEX strip prices as of December 31, 2011.

	Oil	**Gas**	**Total**	**PV-10**
	(MBbls)	**(MMcf)**	**(MBoe)(1)**	**(in thousands)**
SEC Case	7,975	65,962	18,969	$464,314
NYMEX Strip Price Case(2)	7,958	65,951	18,950	$465,423

(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, 2011, as benchmark prices for 2011 through 2017, and continued to use the 2017 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 $106.51 per barrel of oil and $5.13 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 30 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 25 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. Their 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, 2011, our proved undeveloped reserves totaled 5.4 MMBbls of oil and 55.9 Bcf of natural gas, for a total of 14.7 MMBoe compared to 5.2 MMBbls of oil and 55.8 Bcf of natural gas, for a total of 14.5 MMBoe as of December 31, 2010.

All of our proved undeveloped reserves at December 31, 2011 were associated with our Louisiana properties.

We incurred costs relating to the development of proved undeveloped reserves in 2011 of $11.3 million. We incurred no costs relating to the development of proved undeveloped reserves in 2010. Our development of proved undeveloped reserves was deferred during 2010 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.

All proved undeveloped locations are scheduled to be drilled or otherwise converted to proved developed reserves before the end of 2016. 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, 2011.

	2009	**2010**	**2011**
Net Production:			
Oil (Bbl)	626,900	550,000	605,900
Natural gas (Mcf)	2,114,600	1,882,800	2,038,000
Combined volumes (Boe)	979,332	863,800	945,567
Average sales price per Boe	$48.39	$61.05	$80.54
Average production cost per Boe(1)	$20.29	$18.44	$20.93

(1)

Average production cost per Boe excludes severance taxes.

Drilling and Development Activity

Historical

For the year ended December 31, 2011, we completed two productive developmental wells and drilled one exploratory well as a dry hole. We completed no developmental or exploratory wells for the year ended December 31, 2010. A well s completion is reported in the year of completion regardless of when drilling was initiated. 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.

In addition to the wells completed, during 2011 we completed recompletion and/or workover operations on 34 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 2010 and the first quarter of 2011 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, 2011, no wells were being drilled, but two recompletion and/or workover operations were being conducted.

Future Activities

With the addition of liquidity from our capital raising efforts in 2011, together with our improved profitability, commencing in the second quarter of 2011 we increased our development budget and accelerated our development schedule. We have prioritized our inventory of development opportunities to initially focus on development of what we believe are low risk, high return projects, including workovers, recompletions, behind pipe and shut-in projects and development wells, after which we intend to strategically develop our remaining inventory of prospects. During 2012 we plan to use our added liquidity to drill up to 6 development wells and undertake 18 recompletions and/or through-tubing plugbacks. This development work would be spread over four fields with the capital expenditures associated with these projects expected to be approximately $48 million. Our drilling plans and budgets are adjusted periodically based on changing circumstances and results. Depending on the results achieved in pursuing our development projects, the number of projects undertaken during 2012 may increase or decrease, along with the costs of carrying out those projects and the results realized from the same.

Delivery Commitments

At December 31, 2011, 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 oil and natural gas 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 twelve-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. At December 31, 2011, we had no hedges in place. Subject to market conditions, we intend to evaluate reinstituting an active hedging program in conjunction with our efforts to put in place a new revolving credit facility.

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, 2011:

	Gross	**Net**
Oil wells	84	81
Gas wells	23	23
Total	107	104

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, 2011 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, 2011, all of which is located in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana:

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross	Net	Gross	Net	Gross	Net
31,222	31,222	963	963	32,185	32,185

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, 2011, 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, 2012	845	845
December 31, 2013	165	165
December 31, 2014	-	-
December 31, 2015	-	-
December 31, 2016 and later	-	-
Total	1,010	1,010

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.

Sales of oil and gas production to Shell Trading (US) Company and Shell Energy North America (US), L.P. (collectively Shell) accounted for 94% and 68% of our consolidated revenues in 2011 and 2010, respectively. We believe that the loss of Shell 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, 2011, we had 40 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 positive. From time to time, we utilize the services of independent contractors to perform various field and other services.

Regulation of the Oil and Gas Industry

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.

Regulation of Transportation and Sale of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (FERC) regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Interstate oil pipeline rates are typically set based on a cost of service methodology (Cost-Based Rates); however, they may also be set based on the competitive market (Market-Based Rates) or by agreement between the pipeline and its shippers (Settlement Rates). Some oil pipeline rates may be increased pursuant to an index methodology, whereby the pipeline may increase its rates up to a ceiling set by reference to the Producer Price Index for Finished Goods (unless the rate increase is shown to be substantially in excess of the actual cost increases incurred by the pipeline). Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated.

Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states on shore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

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.

We routinely obtain permits for our facilities and operations in accordance with 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 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.

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

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

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

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

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

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

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;

Endangered Species Act and Migratory Bird Treaty Act, which prohibit certain actions that adversely affect endangered or threatened species and migratory birds and their habitat;

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

Occupational Safety and Health Act (OSHA) and comparable state laws and regulations that establish workplace standards for the protection of the health and safety of employees.

The following is a summary of certain existing laws, rules and regulations to which our business operations are subject:

Waste Handling

The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are not currently regulated under RCRA or state hazardous waste provisions though our operations may produce waste that does not fall within this exemption. However, these oil and gas production wastes may be regulated as solid waste under state law or RCRA. It is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation, and Liability Act

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the Superfund Law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

In the course of our operations, we generate wastes that may fall within CERCLA s definition of hazardous substances. Further, we currently own, lease or operate properties that have been used for oil and natural gas exploration and production for many years. Hazardous substances or petroleum may have been released on, at, under or from the properties owned, leased or operated by us, or on, at, under or from other locations, including off-site locations, where such hazardous substances or other wastes have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances, petroleum, or other materials or wastes were not under our control. These properties and the substances or materials disposed or released on, at, under or from them may be subject to CERCLA, RCRA or analogous or other state laws. Under such laws, we could be required to remove previously disposed hazardous substances and address any resulting impacts.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, or OPA, which amends and augments the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. In addition, OPA and regulations promulgated pursuant thereto impose a variety of regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. OPA also requires certain oil and natural gas operators to develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance.

Air Emissions

The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations. Oil and gas operations may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants, including volatile organic compounds, nitrous oxides, and hydrogen sulfide.

Endangered Species, Wetlands and Damages to Natural Resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration or production or seek damages to species, habitat, or natural resources resulting from filling or construction or releases of oil, wastes, hazardous substances or other regulated materials.

Climate Change Legislation and Greenhouse Gas Regulation

Federal, state and local laws and regulations are increasingly being enacted to address concerns about the effects the emission of greenhouse gases may have on the environment and climate worldwide. These effects are widely referred to as climate change. Since its December 2009 endangerment finding regarding the emission of greenhouse gases, the EPA has begun regulating sources of greenhouse gas emissions under the federal Clean Air Act. Among several regulations requiring reporting or permitting for greenhouse gas sources, the EPA finalized its tailoring rule in May 2010 that determines which stationary sources of greenhouse gases are required to obtain permits to construct, modify or operate on account of, and to implement the best available control technology for, their greenhouse gases. In November 2010, the EPA also finalized its greenhouse gas reporting requirements, beginning in March 2012, for certain oil and gas production facilities.

Moreover, in recent past the U.S. Congress has considered establishing a cap-and-trade program to reduce U.S. emissions of greenhouse gases. Under past proposals, the EPA would issue or sell a capped and steadily declining number of tradable emissions allowances to certain major sources of greenhouse gas emissions so that such sources could continue to emit greenhouse gases into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The net effect of such legislation, if ever adopted, would be to impose increasing costs on the combustion of carbon-based fuels such as crude oil, refined petroleum products, and natural gas. In addition, while the prospect for such cap-and-trade legislation by the U.S. Congress remains uncertain, several states have adopted, or are in the process of adopting, similar cap-and-trade programs.

As a crude oil and natural gas company, the debate on climate change is relevant to our operations because the equipment we use to explore for, develop and produce crude oil and natural gas emits greenhouse gases. Additionally, the combustion of carbon-based fuels, such as the crude oil and natural gas we sell, emits carbon dioxide and other greenhouse gases. Thus, any current or future federal, state or local climate change initiatives could adversely affect demand for the crude oil and natural gas we produce by stimulating demand for alternative forms of energy that do not rely on the combustion of fossil fuels, and therefore could have a material adverse effect on our business. Although our compliance with any greenhouse gas regulations may result in increased compliance and operating costs, we do not expect the compliance costs for currently applicable regulations to be material. Moreover, while it is not possible at this time to estimate the compliance costs or operational impacts for any new legislative or regulatory developments in this area, we do not anticipate being impacted to any greater degree than other similarly situated competitors.

Web Site Access to Reports

Our Web site address is *www.saratogaresources.com.* 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. Information contained on, or accessible through, our website is not incorporated by reference into this Form 10-K.

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 then 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.

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

At December 31, 2011, our indebtedness under our term loan totaled $127.5 million (includes unamortized discount of $2.1 million), all of which matures in July 2016. Additionally, we expect to establish a new revolving credit facility in 2012 under which we may incur additional indebtedness.

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, and our anticipated revolving credit facility is expected to include, certain financial covenants that require, among other things, that we satisfy certain interest coverage and asset to liability ratios 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, we may be required to seek alternative financing in order to retire amounts owing under our 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, or are expected to 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 previously resulted in curtailment of our development plans from early 2009 until refinancing of our indebtedness in mid-2011.

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, including proceeds from our 2011 equity capital raises. Since early 2009, we have not had access to borrowing capacity under a revolving credit facility and at December 31, 2011 we lacked a revolving credit facility. The lack of credit availability under our prior revolving credit facility resulted in curtailment of our development program from early 2009 through early 2011. While we resumed our full development plan following receipt of funding from our 2011 equity raises, we continued to lack a revolving credit facility at December 31, 2011. In order to optimize our development program and cash management, we intend to seek to establish a new revolving credit facility in 2012. If our capital requirements vary materially from those reflected in our projections, we may require additional financing provided by a revolving credit facility or other financing sources. 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 may 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 anticipated cash flows from our current and future oil and gas properties.

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. We expect to enter into a revolving credit facility during 2012 and, separately or as part of such facility, to enter into new hedging arrangements. We anticipate that any new revolving credit facility will place limits on our ability to hedge and possibly establish minimum hedging obligations. 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 Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), which was signed into law on July 21, 2010, establishes, among other provisions, federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Commodities Futures Trading Commission (the "CFTC") is required to implement rules relating to these activities by July 16, 2012. On October 18, 2011, the CFTC approved regulations to set position limits for certain futures and option contracts in the major energy markets, which regulations are presently being challenged in federal court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association. The Dodd-Frank Act may also require us to comply with margin requirements and with certain clearing and trade execution requirements in our future derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the counterparties we might otherwise deal with. The schedule for promulgation of final rules has changed repeatedly, but the current schedule published by the Commodities Futures Trading Commission contemplates finishing final regulations in 2012.

The Dodd-Frank Act 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), 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 our use of derivatives is curtailed in the future as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

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.

We may be limited in our ability to maintain or book additional proved undeveloped reserves under the SEC s rules.

We have included in this Form 10-K certain estimates of our proved reserves as of December 31, 2011 prepared in a manner consistent with our and our independent petroleum consultant s interpretation of the SEC rules relating to modernizing reserve estimation and disclosure requirements for oil and natural gas companies. Included within these SEC reserve rules is a general requirement that, subject to limited exceptions, proved undeveloped reserves may only be classified as such if a development plan has been adopted indicating that they are scheduled to be drilled within five years of the date of booking. This rule may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program. Further, if we postpone drilling of proved undeveloped reserves beyond this five-year development horizon, we may have to write off reserves previously recognized as proved undeveloped. During the year ended December 31, 2011 we did not reduce our proved reserve estimates due to the five year development rule.

As of December 31, 2011, approximately 71% of our total proved reserves were undeveloped and approximately 13% of our total proved reserves were developed non-producing. There can be no assurance that all of those reserves will ultimately be developed or produced.

While we have plans or are in the process of developing plans for exploiting and producing a majority of our proved reserves, there can be no assurance that all of those reserves will ultimately be developed or produced. To the extent that we are not the operator of any portion of our proved undeveloped reserves, we may not be in a position to control the timing of all development activities. Furthermore, there can be no assurance that all of our undeveloped and developed non-producing reserves will ultimately be produced during the time periods we have planned, at the costs we have budgeted, or at all, which could result in the write-off of previously recognized reserves.

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 was curtailed from early 2009 until mid-2011 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. While we substantially increased our drilling and development budget following our receipt of equity financing in 2011, we did not have a revolving credit facility in place at December 31, 2011 and, accordingly, fund our drilling and development budget from our funds on hand and operating cash flows. 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.

Our offshore operations involve special risks that could affect our operations adversely.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions, or result in loss of equipment and properties. In particular, we are not intending to put in place business interruption insurance due to its high cost. We therefore may not be able to rely on insurance coverage in the event of such natural phenomena.

Our participation in, and realization of value from, shallow water ultra-deep shelf wells is subject to certain financing and operating risks that may prevent us from realizing the value of our deep reserve potential and expose us to delays, unexpected costs and other adverse financial consequences.

We have identified potential ultra-deep prospects underlying our acreage. The cost of exploration of such prospects, even when limited to our proportionate interest in such costs, is likely beyond that which we could fund from our current financial resources. Accordingly, we intend to seek additional partners to absorb a substantial portion of our share of such exploration costs. To that end, we have entered into discussions with McMoRan Exploration with respect to the potential formation of a joint venture to explore one or more ultra-deep prospects. We have not, as of March 2012, entered into a definitive agreement with McMoRan or any other prospective partner to fund or participate in the exploration of our ultra-deep prospects. In the event that we enter into such a joint venture arrangement but are unable to make satisfactory arrangements to fund our portion of exploration costs, our interests in some of our ultra-deep prospects may be substantially reduced or lost with little or no benefit from such interests accruing to our benefit. Further, the shallow water ultra-deep wells are expected to be some of the deepest wells ever drilled in the world and are subject to very high pressures and temperatures. The drilling, logging and completion techniques are near the limits of existing technologies. As a result, new technologies and techniques are being developed to deal with these challenges. The use of advanced drilling technologies involves a higher risk of technological failure and potentially higher costs. In addition, there can be delays in completion due to necessary equipment that is specially ordered to handle the challenges of ultra-deep wells. Even if we are able to participate in drilling ultra-deep wells there is no assurance that such wells will be commercially viable. Such wells are presently expected to be natural gas wells and, based on the low price of natural gas at December 31, 2011, there is no assurance that the wells can be operated in an economically feasible manner even if successfully completed.

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 us. 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 nature and age of our wells may result in fluctuations in our production resulting from mechanical failures and other factors*.**

The majority of our wells have been in operation and have produced for many years. As a result of the age of those wells and their location in bay environments, those wells typically experience higher maintenance requirements than newer wells and wells located onshore. As a result, some of our wells may periodically be shut-in to perform maintenance or to restore optimal production levels or as a result of maintenance by third parties that operate facilities that serve our wells. Due to the periodic need to shut-in wells, we experience routine fluctuations in production levels with production declining below normal operating capacity during periods of maintenance. Further, because of their location in a bay environment, we sometimes experience delays in identifying and addressing production declines.

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 and Gustav, which required the prior owners of the properties, in the case of Hurricane Katrina, and us, in the case of Hurricane Gustav, 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.

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 presently focused in the shallow waters of the Gulf Coast region and 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.

Proposed legislation may eliminate certain federal income tax deductions currently available with respect to oil and natural gas exploration and development.

President Obama s proposed Fiscal Year 2012 Budget of the U.S. Government includes proposed legislation that would, if enacted, eliminate certain federal income tax deductions currently available with respect to oil and natural gas development. If the United States Congress were to pass legislation eliminating those deductions in accordance with the President s proposal, we would likely experience increased tax liability. This could have a material adverse effect on us, our financial condition and our results of operations.

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 supplemental assessments against multiple oil and gas companies, including Saratoga, for allegedly omitting or undervaluing oil producing assets on the annual self-reporting tax renditions used in calculating ad valorem taxes. In short, the difference between what was reported by the oil and gas companies and what the assessor taxed boiled down to how depreciation of the oil and gas related equipment was calculated and how certain equipment was classified. The amount alleged to be due by Saratoga for the years 2006, 2007, and 2008 is $1.3 million in Parish taxes. Also at issue are the increased assessment valuations for the years 2009, 2010, and 2011 brought by the Parish under the same theory. 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 for the Parish of Plaquemines, Louisiana, and, as to certain issues relating to such claim, in a number of administrative proceedings before the Louisiana Tax Commission. We believe the additional assessment is in error and intend to vigorously defend this action.

On or about January 24, 2010, a vessel operated by Y&S Marine, Inc. ("Y&S") allided (the running of one vessel against another) with the well-head of The Harvest Group, LLC's Well No. 22, located on Breton Sound 32 in Louisiana territorial waters. On July 26, 2010, Y&S filed a complaint for limitation of liability seeking to limit its liability to The Harvest Group, LLC to the value of the vessel, which Y&S claims is approximately $240,000. The Harvest Group, LLC filed an answer and counterclaim in the limitation proceeding against Y&S seeking losses sustained as a result of the allision. The Harvest Group, LLC is seeking damages for all of its uninsured losses, which include approximately $515,000 plus lost production revenue resulting from the shut in of the No. 22 Well. The amount of the lost production has not yet been determined. The Harvest Group, LLC, along with its subrogation insurer St. Paul Surplus Line Insurance Company, filed motions for summary judgment against Y&S on March 6, 2012 seeking the dismissal of certain of Y&S affirmative defenses. Y&S filed a cross motion regarding same. The hearing on the cross motions is set for April 15, 2012. If The Harvest Group, LLC and St. Paul prevail on their summary judgment motions, they will be entitled to move forward to trial, which is currently set for mid-June, 2012.

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 or nonpayment of royalties to the State of Louisiana for periods prior to Saratoga s acquisition of the Harvest Companies and related claims for damages. Specifically, the complaint alleges that the underpayment or nonpayment 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 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 its amended complaint, Saratoga named Henry Calongne and Professional Oil & Gas Marketing as additional defendants 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 with the total principal claims against all defendants being $1.4 million. In addition, certain of the former owners have asserted a counterclaim for $0.2 million for improper collection of joint interest billing credits and Professional Oil & Gas Marketing has asserted counterclaims against Saratoga for $0.2 million for unpaid fees and reimbursable tax payments. Saratoga has concluded settlements with Barry Ray Salsbury, Shell Sibley, Willie Willard Powell and Carolyn Monica Greer. In furtherance of the settlement agreement, Willie Willard Powell has paid Saratoga $77,175.95; Carolyn Monica Greer has paid Saratoga $88,201.08; Barry Ray Salsbury has paid Saratoga $302,062.10; and Shell Sibley has paid Saratoga $302,062.10. Saratoga and these defendants have dismissed the claims and counterclaims asserted against each other. Litigation is still pending as to the remaining defendants, including Brian Carl Albrecht, Professional Oil and Gas Marketing, and Henry Calongne. Presently, the remaining defendants have a motion pending to withdraw the reference from the United States Bankruptcy Court for the Western District of Louisiana to the United States District Court for the Western District of Louisiana.

In February 2011, Saratoga and Harvest Oil & Gas, LLC filed an Original Complaint for money damages in the United States District Court for the Eastern District of Louisiana, citing Key Energy Services, Inc. (Key) as a defendant. Within the complaint, Saratoga and Harvest Oil & Gas, LLC alleged that a master service agreement entered into by the parties for recompletion work was breached when Key did not complete the work in accordance with the agreement. Saratoga and Harvest Oil & Gas, LLC further alleged breach of workmanlike performance, negligence, willful misconduct/gross negligence, and negligent supervision on the part of Key as a result of damage to the well caused by a piece of pipe that was dropped into the well bore. Key filed its answer to the complaint and a counterclaim against Saratoga and Harvest Oil & Gas, LLC. In its counterclaim, Key sought payment of unpaid invoices on the project totaling $0.3 million and foreclosure of its materialman s lien filed in conjunction therewith. The Company reached an out-of court settlement with Key and no cash payments were exchanged. All claims and counterclaims in the lawsuit have been dismissed with prejudice with each party to bear its own costs. Key has released the lien filed against Saratoga s property and the lis pendens (a notice that a law suit is pending that may affect title to property) filed in connection with the litigation.

In March 2011, Harvest Holdings, LLC (Holdings), a Louisiana limited liability company owned by the former owners of The Harvest Group, LLC, filed a petition with the 16th Judicial District Court for the Parish of St. Mary, State of Louisiana, claiming that it owns a production barge located in the Little Bay Field which services The Harvest Group, LLC s production emanating therefrom. On April 26, 2011, Saratoga and The Harvest Group, LLC filed their answer and reconventional demand. In the filing, Saratoga and The Harvest Group, LLC denied the allegations asserted by Holdings and sought a declaratory judgment that The Harvest Group, LLC is the owner of the production barge. In addition, Saratoga and The Harvest Group, LLC asserted a counterclaim in the reconventional demand for a return of certain rental payments actually made by Saratoga and/or The Harvest Group, LLC to Holdings. The parties have reached an out-of-court settlement and dismissed all claims and the reconventional demand. As such, Saratoga stipulated that Holdings is the owner of the production barge and agreed to continue to lease the barge from Harvest Holdings, LLC. The Harvest Group, LLC paid $105,000 in past due rental payments prior to October 1, 2011. In addition, The Harvest Group LLC paid $120,000 for rental payments for October 2011 through March 2012, and will pay $20,000 per month going forward for the balance of the lease of the barge.

We may from time to time be a party to lawsuits incidental to our business. As of December 31, 2011, 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.

Mine Safety Disclosures

Not applicable.

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 NYSE Amex (AMEX) under the symbol SARA . Prior to July 20, 2011, our common stock 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 2011	Fourth Quarter	$	7.40	$	4.13
	Third Quarter		6.51		4.06
	Second Quarter		11.00		2.31
	First Quarter		3.50		2.25
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

At March 21, 2012, the closing price of our common stock on AMEX was $6.64.

As of March 21, 2012, there were approximately 1,542 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. 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, 2011 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)	260,000	4.85	2,740,000
Equity compensation plans not approved by security holders (2)	722,500	2.46	-
Total	982,500	3.09	2,740,000

(1)

Consists of 3,000,000 shares reserved for issuance under the Saratoga Resources, Inc. 2011 Omnibus Incentive Plan (the 2011 Plan). Grants under the 2011 Plan are subject to shareholder approval of the plan, which is expected to be sought at our 2012 annual shareholders meeting.

(2)

Consists of non-plan stand alone stock option grants to directors, employees and consultants. The options are exercisable on terms generally described in Note 10. Common Stock Stock-Based Compensation to our financial statements included herein.

Item 6.

Selected Financial Data

Not applicable.

Item 7.

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

Overview

We are an independent oil and natural gas company engaged in the production, development, acquisition and exploitation of crude oil and natural gas properties. Our properties are located exclusively in the transitional coastline in protected in-bay environments on parish and state leases in south Louisiana. None of our current properties or operations are in the Gulf of Mexico or subject to oversight of the U.S. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE). Our properties span 12 fields which are characterized by over 30 years of development drilling and production history, including Grand Bay field which has over 70 years of production history and over 250 MMBoe produced to date, yet remains virtually unexplored at depths greater than 15,000 feet. Our properties, the majority of which were acquired in July 2008, cover an estimated 32,185 gross/net acres and substantially all are held by production (HBP) without near-term lease expirations. Most of our properties offer multiple stacked reservoir objectives with substantial behind pipe potential.

As of December 31, 2011, our total proved reserves were 19.0 MMBoe, consisting of 8.0 MMBbls of oil and 66.0 Bcf of natural gas. The PV-10 of our proved reserves at December 31, 2011 was $464.3 million based on SEC pricing. The PV-10 of our proved reserves, based on NYMEX strip pricing, was $465.4 million. Additionally, we had probable reserves of 12.9 MMBoe, consisting of 4.0 MMBbls of oil and 53.2 Bcf of natural gas. Moreover, our reserve base includes significant undeveloped and exploratory drilling opportunities.

During 2011, we added 1,889.8 MBoe of proved reserves and produced 945.6 MBoe, of which 64.1% was oil. As of December 31, 2011, our development opportunities included 55 proved behind pipe and shut-in opportunities in 8 fields, 86 proved undeveloped opportunities within 24 proposed wells in 5 fields and 34 probable behind pipe and shut-in development opportunities. Additionally, at December 31, 2011, we had 29 probable undeveloped opportunities, 11 possible behind pipe and shut-in development opportunities and 79 possible undeveloped opportunities. During the year ended December 31, 2011, we completed 2 development wells, 9 recompletions and 25 workovers.

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. As a result of declaring bankruptcy and the absence of availability under our credit facilities, we operated in a liquidity constrained environment from early 2009 through March 2011.

2010 and 2011 Developments

The following significant events, among others, affected our operations and financial position during 2010 and 2011:

Operation in, and Exit from, Bankruptcy

As noted above, from March 31, 2009 until May 14, 2010, we operated as debtors-in-possession under Chapter 11 of the U.S. Bankruptcy Code. During that period, and continuing into 2011, our operations and financial position were characterized by limited access to capital and limited flexibility in carrying out development plans and increased legal, administrative and other costs associated with operations in bankruptcy, including the incurrence of $0.4 million and $2.2 million of reorganization costs in 2011 and 2010, respectively.

On May 14, 2010, our plan of reorganization (the Plan) became effective, our existing debt facilities were amended and we exited bankruptcy.

Under the Plan (1) our revolving credit facility was amended (the Amended Revolving Credit Facility) as to maturity date and interest rate and claims under the facility 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) our term credit facility was amended and restated (the Amended Term Credit Facility) as to maturity and interest rate and claims under the term credit agreement were allowed in the amount of $127.5 million; (3) mineral royalties with accrued interest and penalties owing the Louisiana Department of Mineral Resources were allowed in the amount of $2.0 million (the Mineral Royalty Claims) and were payable in 24 monthly installments; (4) amounts owing on notes payable (the Management Notes) to officers were allowed in the amount of $0.7 million and were payable in full, including compound accrued interest, in 40 months; (5) allowed claims (the Other Allowed Claims) of substantially all other secured and unsecured creditors, totaling approximately $15.0 million were payable, with interest and legal fees, in full with between 75% and 80% of the allowed claims being paid on exit from bankruptcy and the balance being payable in quarterly installments over one year; (6) a warrant (the 2010 Warrant) to purchase 2,000,000 shares of our common stock was issued to the administrative agent for the revolving and term credit facilities; and (6) 483,310 shares of common stock were issued pro rata among the holders of Other Allowed Claims.

During 2011, all remaining unpaid allowed claims under the Plan were paid in full, including the Mineral Royalty Claims, the Management Notes and the Other Allowed Claims and all amounts owing under the Amended Revolving Credit Facility and the Amended Term Credit Facility were repaid in full, and the facilities were terminated, in July 2011 (see Retirement of Debt and Cancellation of Second Warrant below).

Drilling and Development Activities

From early 2009, and continuing following our May 2010 exit from bankruptcy, through the end of the first quarter 2011, we pursued development activities at a curtailed pace supported by our operating cash flow and cash on hand. With our receipt of equity funding (discussed below) in April and July 2011 and improved profitability we increased our capital budget in 2011.

Supplemented by our increased liquidity and capital budget, we accelerated the pace of our development program beginning in April 2011. During 2011, we invested $25.9 million in our drilling and development program and infrastructure projects, up from $9.9 million invested in 2010, summarized as follows:

Development Drilling. During 2011, we drilled two development wells.

The Catina SL 20436 #1 well commenced drilling in July 2011 and was completed during August 2011. The well logged 15 net feet of oil pay in the 10,000 foot sand. The well began production on August 29, 2011 and was tied back to our Main Pass 46 facilities.

The Roux MP 47 SL 195 QQ #24 well (formerly known as QQ #15 Updip well) in Main Pass 47 field reached a total depth of 10,085 feet measured depth (9,200 feet true vertical depth) and encountered 13 pay sands with over 100 net feet of pay. The well was tested and completed in the 21 sand in October 2011. Of the sands encountered, six were previously reflected in our reserves as proved undeveloped, one was reflected as probable undeveloped and six were not previously reflected in our reserves. The well has been tied back to our Main Pass 52 facility for high pressure gas sales and to Grand Bay facilities for low pressure gas and liquids.

Exploratory Drilling. During 2011, we drilled one exploratory well, the Rio Grande well which was a dry hole.

Recompletion and Workover Program. During 2011, we carried out 9 recompletions and 25 workovers. Seven of the nine recompletions were successful, with two recompletions not reaching their objectives due to mechanical issues, although the reserves will stay on the books and be accessed through future development drilling.

Infrastructure Program. During 2011, we invested $5.6 million in infrastructure improvements and additions to support existing production and anticipated increases in production. Principal infrastructure projects during 2011 included installation of a replacement compressor at the Main Pass 25 Field to support higher production from wells supported by that facility through increased compression for gas lift, installation of an 8-mile high pressure pipeline to re-direct production from certain wells and commencing expansion of our Breton Sound 32 facility with increased compression.

Drilling and Development Plans. We have an extensive inventory of drilling opportunities, including numerous proved behind pipe and proved undeveloped opportunities as well as a number of exploratory opportunities. Our near term development plans are focused on proved undeveloped opportunities and conversion of PDNP opportunities. At December 31, 2011, permitting had been completed on five proved undeveloped wells and permitting was underway on five additional proved undeveloped wells, including three wells in our Vermilion 16 field. We presently anticipate drilling six proved undeveloped wells during 2012 and five to six development wells annually thereafter from an existing inventory of 46 proved undeveloped wells. In anticipation of development of our Vermilion 16 field, we are presently undertaking efforts to expand our handling and infrastructure capacity in the field.

In addition to our program of converting proved undeveloped and PDNP opportunities, during 2011 we continued efforts to secure partners for the exploration and development of ultra-deep prospects in our Grand Bay and Vermilion 16 fields. Those efforts resulted in entry into discussions with McMoRan Exploration Company with regard to the possible formation of a joint venture to explore ultra-deep prospects. As of March 2012, we had not yet entered into a joint venture agreement with McMoRan.

We continually evaluate our holdings with a view to optimizing our drilling and development plans based on ongoing development efforts, new geological and operating data, identification or acquisition of new opportunities and other factors. Accordingly, our drilling and development plans are fluid and subject to continuous revision and may vary from the plans described herein.

Leasehold and Seismic Activity

Termination of Clayton Williams Energy Farmout in Grand Bay Field. During 2011, we terminated our farmout agreement with Clayton Williams Energy covering approximately 2,000 gross acres in the northwest portion of our Grand Bay Field. Pursuant to the termination of that farmout, we paid to Clayton Williams Energy $506,425 and assumed full control, operation and ownership of 100% of the working interest in the subject acreage.

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, made monthly installments of $80,000 for ten months ending March 2011.

Production Handling Fees

During 2010, we discovered an error in third party billings for production handling services we provided between 2006 and 2009. In 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 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 was unhedged from February 2010 through year end 2011 and is currently unhedged.

Compensation

In March 2011, our board of directors approved a revised compensation program for non-employee directors, consisting of annual stock option grants to acquire 35,000 shares of stock, together with cash retainers for board service and committee chairs. Pursuant to the revised compensation program, we granted stock options to purchase an aggregate of 105,000 shares of common stock to our non-employee directors, including options granted to a newly appointed director. 70,000 of the options are exercisable at $3.05 per share and 35,000 of the options are exercisable at $2.80 per share, the grant date closing price of our stock. The options are exercisable for terms of seven years and vest 50% on the grant date and 50% on the first anniversary of the grant date.

In July 2011, we paid one-time bonuses totaling $225,000 to five officers and key employees principally involved in our financing efforts described below.

In March 2012, our compensation committee approved bonuses totaling $200,000 to two officers relating to services during 2011. Those bonuses were recorded as compensation expense and are reflected in general and administrative expenses during 2011.

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 were subject to different vesting periods.

In addition to the option grants on exit from bankruptcy described above, during 2010, we granted stock options to purchase an aggregate of 447,500 shares of common stock to newly hired and existing employees and consultants, including 140,000 stock options granted to two officers, with exercise prices ranging from $1.39 to $1.71 per share. The options were subject to different vesting periods, including performance based vesting with respect to options granted to a consultant.

As a result of the stock option grants during 2010 (including non-employee director grants), we recorded $471,946 of compensation charges that are reflected in general and administrative expense.

During 2010, a total of 350,000 stock options were forfeited.

During 2011, we granted stock options to purchase an aggregate of 105,000 shares of common stock to non-employee directors, including one newly appointed director. The options had exercise prices ranging from $2.80 to $3.05 per share and vested 50% on the grant date and 50% one year from the grant date

In addition to the option grants to non-employee directors described above, during 2011, we granted stock options to purchase an aggregate of 290,000 shares of common stock to newly hired employees, including one newly hired executive, with exercise prices ranging from $2.75 to $5.63 per share.

As a result of the stock option grants during 2011 (including non-employee director grants), we recorded $471,173 of compensation charges that are reflected in general and administrative expense.

During 2011, a total of 201,667 stock options were forfeited.

As of December 31, 2011, total compensation cost related to unvested stock option awards not yet recognized in earnings was approximately $1.2 million, which is expected to be recognized over a weighted average period of approximately 0.93 years.

Warrant

During 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.

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 paid monthly cash consulting fees.

During 2011, we terminated the consulting agreement for finance and business development services.

Share Issuances for Cash

In April 2011, we sold to U.S. and non-U.S. accredited investors, in a private placement, an aggregate of 2,481,316 shares of common stock and warrants to purchase 1,240,658 shares of common stock. The shares and warrants were offered in units of two shares and one warrant at $6.00 per unit for aggregate gross proceeds of $7,443,948. The warrants are exercisable for two years to purchase shares of common stock at $5.00 per share. Pursuant to the offering, we issued 84,600 shares of common stock and warrants to purchase 42,300 shares of common stock to a placement agent with respect to units sold to non-U.S. investors.

In July 2011, we sold to U.S. and non-U.S. accredited investors, in a private placement, an aggregate of 5,650,000 shares of common stock at a price of $5.00 per share. Net proceeds from the sale of shares were approximately $27.3 million of which $20.0 million was deposited directly into a third party escrow account to be applied to retirement of indebtedness under our prior credit facilities. Pursuant to the offering, we issued 38,200 shares of common stock to a placement agent with respect to units sold to non-U.S. investors.

During 2011, we sold 45,000 shares of common stock for $43,200 in cash pursuant to the exercise of outstanding stock options.

Sale of 2016 Notes

In July 2011, we and our subsidiaries (the Guarantors) entered into a Purchase Agreement with Imperial Capital, LLC, relating to the issuance and sale of $127.5 million in aggregate principal amount of our 12.5% Senior Secured Notes due 2016 (the 2016 Notes). The 2016 Notes were sold at 98.221% of par. The 2016 Notes were offered and sold in a transaction exempt from the registration requirements of the Securities Act of 1933 and were resold to qualified institutional buyers in reliance on Rule 144A of the Securities Act and to persons outside of the U.S. pursuant to Regulation S.

The 2016 Notes are our senior secured obligations and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with our and the Guarantors existing and future senior indebtedness.

The 2016 Notes mature on July 1, 2016, and interest is payable on the 2016 Notes on January 1 and July 1 of each year, commencing January 1, 2012.

The indenture (the Indenture) pursuant to which the 2016 Notes were issued includes customary events of default and places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

We have the option to redeem all or a portion of the 2016 Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture plus accrued and unpaid interest. We may also redeem the 2016 Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to January 1, 2014. Within each twelve-month period commencing on July 12, 2012 and ending January 1, 2014, we may also redeem up to 10% of the aggregate principal amount of the 2016 Notes at a price equal to 106.25% of the principal amount thereof, plus accrued and unpaid interest. In addition, we may redeem up to 35% of the 2016 Notes prior to January 1, 2014 under certain circumstances with the net cash proceeds from certain equity offerings and at a price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest.

Registration Rights Agreements

In connection with the issuance and sale of the 2016 Notes, we and the Guarantors entered into a registration rights agreement (the Registration Rights Agreement) with Imperial Capital. Pursuant to the Registration Rights Agreement, we and the Guarantors agreed to file a registration statement with the Securities and Exchange Commission (the SEC) so that holders of the 2016 Notes can exchange the 2016 Notes for registered notes that have substantially identical terms as the 2016 Notes. In addition, we and the Guarantors agreed to exchange the guarantee related to the 2016 Notes for a registered guarantee having substantially the same terms as the original guarantee. We and the Guarantors agreed to use reasonable best efforts to cause a registration statement with respect to the exchange to be filed within 90 days after the issuance of the 2016 Notes and declared effective under the Securities Act within 180 days after the issuance of the 2016 Notes. In the event of a failure to comply with our obligations to register the 2016 Notes within the specified time periods or to continue to maintain the effectiveness of the registration (a Registration Default), the interest rate on the 2016 Notes will be increased by 0.25% for each 90 days that such Registration Default continues, provided that the increase in interest rate shall in no event exceed an aggregate of 1.0% and provided, further, that upon cure of any such Registration Default the interest rate on the 2016 Notes will be reduced to its original rate. A registration statement relating to the exchange of the 2016 Notes was filed on September 26, 2011 and was declared effective by the Securities and Exchange Commission on October 19, 2011. Following the effectiveness of the registration statement, the Company completed the exchange of registered notes for the unregistered 2016 Notes.

In connection with the July 2011 issuance and sale of shares, we entered into a registration rights agreement (the Equity Registration Rights Agreement) with the purchasers of the shares. Pursuant to the Equity Registration Rights Agreement, the holders of a majority of the shares will have a demand registration right pursuant to which we may be required to file with the SEC one or more registration statements covering the resale of the shares. Additionally, the Equity Registration Rights Agreement provides piggyback registration rights to the holders of the shares pursuant to which the holders are entitled to notice of the filing of certain registration statements and inclusion of some or all of the shares in any such registration statements.

Retirement of Debt and Cancellation of Second Warrants

In July 2011, we repaid in full all outstanding indebtedness under our prior credit facilities with a portion of the proceeds from the July 2011 sale of 2016 Notes and shares and, in conjunction therewith, retired letter of credit obligations totaling $10.2 million. Further, the warrants (the Second Warrants) to purchase 2,000,000 shares issued to the administrative agent of those facilities, dated May 14, 2010, were cancelled in connection with the repayment of the indebtedness. As a result of retirement of the debt and cancellation of the Second Warrants, the Company realized a gain on extinguishment of debt of $7.7 million, wrote off $2.8 million of unamortized debt discount and debt issuance costs and reduced additional paid-in capital by $10.6 million.

Share Issuance on Exercise of Warrants

During 2011, we issued an aggregate of 1,055,516 shares of common stock pursuant to the exercise of warrants. A warrant to acquire 805,516 shares of common stock at $0.01 per share was exercised on a cashless basis pursuant to which the intrinsic value of the warrant was delivered in lieu of a cash payment of the exercise price, resulting in the issuance of 803,764 shares and a warrant to acquire 250,000 shares of common stock at $0.25 per share was exercised on a cashless basis pursuant to which the intrinsic value of the warrant was delivered in lieu of a cash payment of the exercise price, resulting in the issuance of 239,984 shares.

Retirement of Uncontested Bankruptcy Claims

During 2011, we paid the balance owing with respect to the state lessor royalty audit (excluding penalties with respect to which we received a waiver) and notes payable to officers, being the last of the unpaid uncontested claims under our Plan of Reorganization. Amounts paid in settlement of uncontested claims under our Plan of Reorganization totaled $3.2 million during 2011.

Critical Accounting Policies

We prepare our consolidated 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. Commodity prices are based on the average prices as measured on the first day of each of the last twelve calendar months. In our 2011 year-end reserve report, we used an average oil price of $106.51 per Bbl, and a natural gas price of $5.13 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.

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, 2011 was immaterial.

Derivative Instruments

We account for 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

Pursuant to the provisions of our Plan of Reorganization and under the terms of an Amended and Restated Term Credit Agreement, our term credit facility was revised during 2010 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 included 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, 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, 2011 Compared to Year Ended December 31, 2010

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. During that period, and continuing through completion of our capital raising efforts in mid-2011, our operations, and operating results, were significantly affected by, 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 2011 increased by 44.6% to $76.2 million from $52.7 million in 2010.

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The increase in revenue was attributable to a 31.9% increase in average hydrocarbon prices realized during 2011 and a 9.5% increase 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, 2011 and 2010:

		2011		**2010**
Revenues				
Oil	$	67,601,949	$	44,141,235
Gas		8,557,319		8,592,972
Total oil and gas revenues	$	76,159,268	$	52,734,207
Production				
Oil (Bbls)		605,900		550,000
Gas (Mcf)		2,038,000		1,882,800
Total production (Boe)		945,567		863,800
Average sales price				
Oil (per Bbl)	$	111.57	$	80.26
Gas (per Mcf)		4.20		4.56
Total average sales price (per Boe)	$	80.54	$	61.05

The increase in production during 2011 was attributable to our recompletion and workover program, drilling of our Catina and Roux wells and efforts during 2011 to address deferred maintenance and third party facilities capacity limitations that resulted in the resumption of production or increase in production from shut-in wells and wells producing below capacity. The increase in production during 2011 reflects additional investment in, and acceleration of, our development and drilling plan commencing in the second quarter of 2011 which, in turn, reflected our strengthened cash position attributable to capital raising efforts and improved operating cash flows. Investments in our drilling and development program totaled $20.3 million in 2011 as compared to $7.7 million in 2010.

The increase in average prices realized from the sale of oil and gas reflected a sharp rise in global commodity prices, in particular crude oil prices, beginning in late 2010 and continuing through 2011. Our increase in average prices realized also reflects a premium to prevailing WTI prices as a result of the quality of our LLS and HLS oil production. At December 31, 2011, we were fully unhedged and, during 2011, benefited from rising oil prices and premiums to prevailing WTI prices while also being exposed to declining natural gas 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, (iii) in 2010, proceeds from the sale of our Adcock Farms lease and well, and (iv) in 2011, refunds of severance taxes under a Louisiana incentive program relating to previously inactive wells. For 2011, other revenues increased to $6.2 million from $2.3 million in 2010. The increase in other revenues was principally attributable to severance tax refunds of $2.6 million received during 2011.

Operating Expenses

Operating expenses increased by 16.0% to $57.1 million for 2011 from $49.2 million in 2010. The following table sets forth the components of operating expenses, in total and on a per Boe basis, for 2011 and 2010:

	2011		**2010**	
	Total	**Per Boe**	**Total**	**Per Boe**

Lease operating expense	$ 17,123,890	$ 18.11	$ 13,774,406	$ 15.95
Workover expense	2,666,600	2.82	2,154,482	2.49
Exploration expense	596,065	0.63	1,921,943	2.22
Loss on plugging and abandonment	393,599	0.42	-	-
Dry hole costs	3,912,823	4.14	-	-
Depreciation, depletion and amortization	15,591,048	16.49	16,001,826	18.52
Impairment expense	641,791	0.68	-	-
Accretion expense	1,672,900	1.77	1,668,268	1.93
Gain on revision of asset retirement obligations	(303,633)	(0.32)	-	-
Gain on purchase price adjustment	(1,426,778)	(1.51)	-	-
Loss on settlement of accounts payable	-	-	990,786	1.15
General and administrative expenses	8,704,536	9.21	8,476,124	9.81
Production and severance taxes	6,090,666	6.44	5,214,677	6.04
	$ 55,663,507	$ 58.87	$ 50,202,512	$ 58.12

As more fully described below, the change in operating expenses was primarily attributable to increased lease operating expense, workover expense, loss on plugging and abandonment, dry hole costs and production and severance taxes, partially offset by decreased exploration expense.

Lease Operating Expenses

Lease operating expenses for 2011 increased 24.3% to $17.1 million, or $18.11 per Boe, from $13.8 million, or $15.95 per Boe, in 2010.

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. The increase in lease operating expenses during 2011 was primarily attributable to increases in equipment rental, transportation expense and field personnel.

Workover Expense

Workover expense for 2011 increased 23.8% to $2.7 million from $2.2 million in 2010. The increase in workover expense was attributable to more workover activity in 2011.

Exploration Expense

Exploration expense for 2011 decreased 69.0% to $0.6 million from $1.9 million in 2010. The decrease in exploration expense was attributable to the completion of our full field study program in early 2011 and the 2010 purchase of a seismic data license ($0.7 million).

Loss on plugging and abandonment

Loss on plugging and abandonment was $0.4 million in 2011 due to the cost of plugging and abandoning wells in the Breton Sound 51 field that exceeded those estimated in our calculation of asset retirement obligation liabilities

Depreciation, Depletion, Amortization and Impairment (DD&A)

Depreciation, depletion and amortization for 2011 increased 1.4% to $16.2 million from $16.0 million in 2010. Changes in DD&A were attributable 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. During the year ended December 31, 2011, Saratoga recorded an impairment expense of $0.6 million relating to one property when development costs incurred during the year combined with the existing carrying value exceeded the fair value.

Accretion expense

Accretion expense for 2011 remained unchanged from 2010 at $1.7 million.

Gain on revision of asset retirement obligation

Gain on revision of asset retirement obligation was $0.3 million due to downward revisions in the asset retirement obligations relating to one property which exceeded the carrying amount of the property

Gain on purchase price adjustment

Gain on purchase price adjustment was $1.4 million due to adjustments to the original purchase price of certain of Saratoga s assets, relating to site specific trust accounts, which occurred longer than one year after the acquisition date.

Loss on settlement of accounts payable

Loss on settlement of accounts payable reflects the fair value of the common stock issued, on a one-time basis, to our vendors during 2010 as part of the settlement terms in our plan of reorganization.

General and Administrative Expenses and Other

General and administrative expense for 2011 increased 2.7% to $8.7 million from $8.5 million in 2010. The increase in general and administrative expense was attributable to increased compensation expense ($2.6 million) relating to salary increases, additional head count and cash bonuses partially offset by a decrease in stock-based compensation. The change in stock-based compensation was attributable to broad based stock option grants with immediate vesting during 2010 in connection with our exit from bankruptcy. Non-cash G&A expense, associated principally with stock-based compensation, totaled $0.9 million and $2.6 million in 2011 and 2010, respectively.

Severance Taxes

Severance taxes for 2011 increased 16.8% to $6.1 million from $5.2 million in 2010. The increase was primarily due to increased production and prices partially offset by decreased severance tax rates for our natural gas production that began in July 2010 and severance tax incentives relating to previously inactive wells.

Other Income (Expense), Net

Net other expenses totaled $10.8 million for 2011 as compared $21.8 million for 2010. The following table sets forth the components of net other income (expenses) for 2011 and 2010:

		2011		**2010**
Commodity derivative income (expense)	$		$	696,550
Financing expense		(837,364)		
Gain on extinguishment of debt		7,708,486		
Interest expense (net)		(17,698,849)		(22,469,584)
	$	(10,827,727)	$	(21,773,034)

As more fully described below, the changes in other income (expense), net, were principally attributable to the gain realized in the 2011 on the extinguishment of debt, liquidation of our commodity derivates during 2010, resulting in a gain for 2010 compared to no income or expense from commodity derivatives during 2011, financing expenses incurred during 2011 relating to a revolving credit facility and a decrease in interest expense reflecting a lower average interest rate on borrowed funds.

Commodity Derivative Income (Expense). Commodity derivative income decreased to $0 during 2011 from $0.7 million during 2010. The commodity derivative income recognized during 2010 related to the liquidation of our commodity derivatives during 2010. We had no commodity derivative activities during 2011.

Financing Expense. Financing expense consists of commitment fees and costs associated with the planned establishment of a revolving credit facility during 2011. We opted to seek more favorable credit terms in lieu of closing the revolving credit facility resulting in our expensing all costs associated with efforts to establish the facility.

Gain on Extinguishment of Debt. Gain on extinguishment of debt totaled $7.7 million during 2011. The gain on extinguishment of debt relates to the 2011 retirement of indebtedness under our prior credit facilities and reflects the fair market value of the warrants cancelled on retirement of that debt net of unamortized debt issuance costs and debt discount.

Interest Expense, Net. Interest expense, net, reflects interest incurred on debt under our term credit agreement and revolving credit agreement which were retired in July 2011 and our new senior secured notes which were issued in July 2011, partially offset by interest earned on cash balances held. Net interest expense decreased to $17.7 million in 2011 from $22.5 million in 2010. The decrease in net interest expense was attributable to a May 2010 decrease in our stated interest rate on our Amended and Restated Term Credit Agreement from 20% to 11.25% and, to a lesser extent, an increase in interest income resulting from an increase in our cash balances partially offset by an increase in the stated interest rate of our senior secured notes to 12.5% commencing in July 2011.

Reorganization Expenses

Reorganization expenses reflect payments to professionals and other fees incurred in connection with our Chapter 11 case. Reorganization expenses decreased to $0.4 million in 2011 from $2.2 million in 2010 due to our exit from bankruptcy in May 2010.

Income Tax Provision

For 2011, we recorded an income tax benefit of $6.8 million compared to income tax expense of $0.3 million for 2010. The income tax expense for 2010 was attributable to Louisiana state franchise taxes. For 2011, we recognized a deferred tax asset relating to our net operating loss carryforwards.

Our effective tax rates for 2011 and 2010 were (49.1)% and (1.5)%, 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.

Following our exit from bankruptcy in May 2010, we have continued to fund operations out of operating cash flow and cash on hand, which funds have been supplemented by our receipt of funds from our April and July 2011 capital raises described herein. From prior to our bankruptcy filing in March 2009 through the retirement of our revolving credit facility in July 2011, we did not have access to available capital under our revolving credit agreement. In conjunction with our July 2011 financing, we received a commitment letter with respect to establishing a new revolving credit facility. At December 31, 2011, and continuing as of this writing, we had not yet established a revolving credit facility and continue to evaluate multiple potential options regarding the establishment of such a facility.

Since exit from bankruptcy, under the terms of our Modified Third Amended Plan of Reorganization (the Plan of Reorganization), we made principal and interest payments to our creditors of approximately $17.3 million on exit from bankruptcy, $2.3 million during the balance of 2010, and $3.2 million during 2011. At December 31, 2011, all uncontested claims had been paid in full under the Plan of Reorganization (excluding $0.4 million of penalties with respect to a state lessor royalty audit, which penalties were waived).

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 from wells producing below capacity and an inventory of proved developed nonproducing opportunities. Mid-term, following or in conjunction with execution of short-term opportunities, our focus is on the development of an inventory of proved undeveloped opportunities within our inventory of proved undeveloped wells 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.

As noted, during April 2011, we received $7.4 million from the sale of common stock and warrants. Additionally, during April 2011, we received $1.3 million net of fees from severance tax incentive refunds and $1.3 million from a one-time insurance settlement. We utilized the proceeds from the offering of such stock and warrants and such additional payments to support accelerated investments in our development and maintenance program.

Further, during July 2011, we received $27.3 million of net proceeds from the sale of common stock and $120.9 million of net proceeds from the sale of our 2016 Notes. $20.0 million of the $27.3 million and all of the $120.9 million was deposited into third party escrow accounts for application to repay indebtedness under our prior credit facilities.

We believe that our cash flows from operations and cash on hand, including funds received from our equity and note offerings, one time payments and improved profitability, are sufficient to support our liquidity needs for the next twelve months, including funding all of our current short-term objectives, including investments in planned infrastructure and deferred maintenance, recompletions, workovers and through-tubing plugbacks. We believe that our cash flows from operations and cash on hand will also be sufficient to pursue our current 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 any further 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, 2011, and as of March 2012, we were in active discussions with McMoRan Exploration regarding the formation of a joint venture to explore our deep shelf prospects. We presently lack the financial resources to carry our proportionate share of the anticipated exploration and development costs associated with such joint venture and will be required to secure additional financing to support our share of such costs and maintain our interest in such ultra-deep prospects. To that end, we expect to seek additional partners to enter into arrangements that will provide the necessary funding to pay some, or all, of our share of the joint venture costs with the effect of reducing our interest in the joint venture. We presently have no commitments to provide funding to cover our share of such costs.

Unexpected declines in commodity prices or production levels, or failures in achieving production increases through short- and mid-term development plans, could result in our inability to support our operations and drilling and development plans.

Further, as noted above, in order to further supplement our liquidity and increase our operating flexibility, we intend to enter into a new revolving credit facility. To that end, we entered into discussions with a potential lender in connection with our July 2011 offerings of 2016 Notes and equity and entered into a commitment letter relating to the establishment of a revolving credit facility in an amount up to $35 million subject to a borrowing base and other conditions commonly associated with such facilities. We continue to pursue efforts in that regard to finalize the terms and enter into a definitive agreement to provide a revolving credit facility but, as of this writing, have not yet established such a facility and there can be no assurance that we will be successful in establishing a revolving credit facility on terms that we consider to be favorable or at all.

Cash, Cash Flows and Working Capital

We had a cash balance of $15.9 million and working capital of $8.5 million at December 31, 2011 as compared to a cash balance of $4.4 million and working capital of $2.6 million at December 31, 2010. The increase in cash on hand and working capital is primarily attributable to the receipt of proceeds from our April 2011 placement of common stock and warrants and our July 2011 placements of common stock and 2016 Notes, receipt of one time payments of $2.6 million from an insurance settlement and from severance tax refunds and improved profitability associated with improved commodity prices partially offset by retirement of indebtedness under our prior credit facilities, payments to creditors as provided for in our plan of reorganization, and increased development expenditures.

Operations provided cash flow of $33.8 million during 2011 as compared to using $1.4 million during 2010. The change in operating cash flows during 2011 was principally attributable to increased revenues and decreased payments related to the bankruptcy. During 2010, we paid approximately $14.1 million to creditors from cash flows from operating activities.

Investing activities used cash flows of $30.5 million during 2011 as compared to $10.2 million used during 2010. The increase in cash used in investing activities during 2011 was attributable to acceleration of our development and drilling plans and investments in infrastructure projects following our receipt of funding from our April 2011 common stock and warrant placement.

Financing activities provided cash flows of $8.1 million during 2011 as compared to $5.6 million used during 2010. Cash flows provided by financing activities during the 2011 period related to short-term notes payable issued for insurance premiums and funds received from our April 2011 private placement of common stock and warrants and July 2011 private placement of common stock and notes, all partially offset by retirement of indebtedness under our prior credit facilities and payments for insurance premiums. During 2010, we paid $5.5 million toward reduction of the principal balance outstanding under our revolving credit facility. Cash flows from financing activities reflects the net cash received from our July 2011 placement of equity but exclude proceeds from the equity placement and 2016 Note placement that were funded into escrow and applied directly to retire indebtedness. The repayment of amounts owing under our prior credit facilities (totaling $145.2 million), including retirement of letter of credit obligations ($10.2 million), and the receipt of funds from the July 2011 equity placement and placement of 2016 Notes (each to the extent funded into escrow and applied to repayment of the indebtedness) were reported as noncash financing activities.

Debt

At December 31, 2011, we had $125.4 million of indebtedness outstanding, consisting of $127.5 million in face amount of 12.5% Senior Secured Notes due 2016 less $2.1 million of debt discount.

We had no letters of credit outstanding at December 31, 2011.

As noted, in July 2011, we issued our 2016 Notes and retired all obligations owing under our prior credit facilities and all outstanding letter of credit obligations.

The 2016 Notes are our senior secured obligations and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with our and the Guarantors existing and future senior indebtedness. The 2016 Notes mature on July 1, 2016, and interest is payable on the 2016 Notes on January 1 and July 1 of each year, commencing January 1, 2012.

We have the option to redeem all or a portion of the 2016 Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture pursuant to which the 2016 Notes were issued plus accrued and unpaid interest. We may also redeem the 2016 Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to January 1, 2014. Within each twelve-month period commencing on July 12, 2012 and ending January 1, 2014, we may also redeem up to 10% of the aggregate principal amount of the 2016 Notes at a price equal to 106.25% of the principal amount thereof, plus accrued and unpaid interest. In addition, we may redeem up to 35% of the 2016 Notes prior to January 1, 2014 under certain circumstances with the net cash proceeds from certain equity offerings and at a price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest.

Capital Expenditures

Our capital spending for 2011 was $25.9 million relating primarily to development of our oil and gas properties, including drilling two development wells and one exploratory well, nine recompletions and investments in multiple infrastructure projects. Capital expenditures were up from $10.2 million during 2010.

The increase in capital expenditures during 2011 was attributable to improvements in our operating performance and the receipt of $7.4 million from our April 2011 equity offering and receipt of $2.6 million of one-time payments which allowed us to increase our capital expenditure budget beginning in late April 2011.

As of March 1, 2012, we anticipate that our capital budget for 2012 will be approximately $47.6 million, excluding potential acquisitions and capital requirements associated with our proposed joint venture with McMoRan Exploration. 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, 2011:

Payments due by period

	Total	2012	2013 2014	2015 2016	Thereafter
Debt [1]	$ 127,500,000	$ -	$ -	$ 127,500,000	$ -
Operating leases	142,356	84,924	57,432	-	-
Capital leases	-	-	-	-	-
Asset retirement obligations	45,798,500	1,987,500	-	3,525,000	40,286,000
Total	$ 173,440,856	$ 2,072,424	$ 57,432	$ 131,025,000	$ 40,286,000

(1)

Debt consists of amounts owing under our 2016 Notes.

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. At December 31, 2011, 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, 2011.

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. At December 31, 2011, 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.

Interest Rate Risk

We consider our interest rate risk exposure to be minimal as a result of fixing interest rates on our existing debt. In the event that we put in place a new revolving credit facility, we anticipate that borrowings under such a facility will bear interest at a floating rate in which case we would be exposed to risk associated with such fluctuation. Pursuant to the terms of our existing debt, any such new revolving credit facility will initially be limited to no more than $35 million.

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 54 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, 2011 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, 2011.

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, 2011, 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, 2011.

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 2011 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

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Executive Officers

Our executive officers as of December 31, 2011, and their ages and positions as of that date, are as follows:

Name	Age	Position
Thomas F. Cooke	63	Chief Executive Officer and Chairman
Andrew Clifford	56	President
Michael Aldridge	53	Executive Vice President and Chief Financial Officer
Brian Daigle	52	Vice President Operations
Randal McDonald, Jr.	54	Controller

The following is a biographical summary of the business experience of our 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 30 years.

Andrew C. Clifford has served as our President and a Director since October 2007. He is a petroleum geologist/geophysicist with over 33 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.

Michael Aldridge has served as our Executive Vice President and Chief Financial Officer since October 2011. Prior to joining our company, from 2000 to 2008, Mr. Aldridge served in various executive roles with Petroquest Energy, Inc., an NYSE-listed independent oil and gas company, including serving as Chief Financial Officer and a Director commencing in 2000, as Treasurer commencing in 2001 and as Executive Vice President commencing in 2006. From 2009 until joining our company, Mr. Aldridge served as a financial consultant to the energy industry. From 1992 to 1999, Mr. Aldridge served first as Vice President Controller and then as Vice President Corporate Communications for Ocean Energy, Inc., a public oil and gas exploration and development company. From 1991 to 1992, he served as Chief Financial Officer for Fleet Petroleum Partners, an independent exploration and production company. Prior to this, he served the oil and gas industry for eleven years with Ernst & Young LLP, where he attained the level of Senior Manager. Mr. Aldridge earned a Bachelor of Science in Accounting from Louisiana State University and is a Certified Public Accountant.

Brian Daigle has served as our Vice President Operations since July 2010. Previously, Mr. Daigle served as Operations Manager of Harvest Oil and Gas, LLC and The Harvest Group, LLC (together, 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.

Randal McDonald, Jr. has served as our Controller since November 2011. Previously, from 2007 to 2011, Mr. McDonald served as Controller of Baseline Oil & Gas Corp., an independent oil and gas company. From 1998 until 2007, Mr. McDonald served as Chief Financial Officer and a Director of VTEX Energy, Inc., a publicly traded independent oil and gas company. Mr. McDonald holds a B.B.A. degree in Accounting from the University of Texas at Austin and is a licensed Certified Public Accountant.

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.

Item 11.

Executive Compensation

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Item 12.

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

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Equity compensation plan information is set forth in Part II, Item 5 of this Form 10-K.

Item 13.

Certain Relationships and Related Transactions, and Director Independence

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

Item 14.

Principal Accountant Fees and Services

The information required by this Item will be included in a definitive proxy statement, pursuant to Regulation 14A, to be filed not later than 120 days after the close of our fiscal year. Such information is incorporated herein by reference.

PART IV

Item 15.

Exhibits and Financial Statement Schedules

1.

Financial statements. See Index to Financial Statements on page 54 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	Amended and Restated Bylaws of Saratoga Resources, Inc., dated May 16, 2011	8-K	5/20/11	3.1	
4.1	Indenture Agreement, dated July 12, 2011, by and among Saratoga Resources, Inc., the guarantors named therein, and The Bank of New York Mellon Trust Company, N.A., as trustee	8-K	7/15/11	4.1	
4.2	Registration Rights Agreement, dated July 12, 2011, by and among Saratoga Resources, Inc., the guarantors named therein, and Imperial Capital, LLC	8-K	7/15/11	4.2	
4.3	Form of Registration Rights Agreement, dated July 12, 2011, by and among Saratoga Resources and purchasers of common stock	8-K	7/15/11	4.3	
10.1	Form of Securities Purchase Agreement, dated April 2011	8-K	4/27/11	10.1	
10.2	Form of Warrant issued to Investors, dated April 2011	8-K	4/27/11	10.2	
10.3	Employment Agreement, dated October 9, 2007, with Thomas Cooke*	8-K	10/11/07	10.2	
10.4	Employment Agreement, dated October 8, 2007, with Andrew Clifford*	8-K	10/11/07	10.3	
10.5	Form of Securities Purchase Agreement, dated July 11, 2011, by and among Saratoga Resources, Inc. and various purchasers of common stock	8-K	7/15/11	10.1	
10.6		8-K	7/15/11	10.2	

	Form of Securities Purchase Agreement, dated July 11, 2011, by and among Saratoga Resources, Inc. and various purchasers of common stock				
10.7	Investor Rights Agreement, dated July 12, 2011	8-K	7/15/11	10.3	
10.8	Saratoga Resources, Inc. 2011 Omnibus Incentive Plan	S-8	9/13/11	10.1	
10.9	Subordinated Promissory Note, dated July 14, 2008, payable to Thomas F. Cooke	8-K	7/18/08	10.6	
10.10	Subordinated Promissory Note, dated July 14, 2008, payable to Andrew C. Clifford	8-K	7/18/08	10.7	
10.11	Saratoga Resources, Inc. Annual Incentive Plan*	8-K	03/23/12	10.1	
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 MaloneBailey, LLP				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 26, 2012		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)	March 26, 2012
/s/ Andrew C. Clifford Andrew C. Clifford	President and Director	March 26, 2012
/s/ Kevin Smith Kevin Smith	Director	March 26, 2012
/s/ Rex H. White, Jr. Rex H. White, Jr.	Director	March 26, 2012
/s/ John W. Rhea, IV John W. Rhea, IV	Director	March 26, 2012
/s/ Michael Aldridge Michael Aldridge	Executive Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	March 26, 2012

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 its subsidiaries (collectively, the Company) as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders equity (deficit), and cash flows for each of 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 Saratoga Resources, Inc. and its subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of 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 26, 2012

Saratoga Resources, Inc.

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,874,680	$ 4,409,984
Accounts receivable	10,539,757	9,039,836
Prepaid expenses and other	1,189,406	888,717
Deferred tax asset, net	1,400,000	-
Other current assets	150,000	300,000
Total current assets	29,153,843	14,638,537
Property and equipment:		
Oil and gas properties - proved (successful efforts method)	196,101,827	170,870,775
Other	658,113	561,572
	196,759,940	171,432,347
Less: Accumulated depreciation, depletion and amortization	(53,830,820)	(37,597,980)
Total property and equipment, net	142,929,120	133,834,367
Deferred tax asset, net	5,147,962	-
Other assets, net	20,531,218	2,870,379
Total assets	$ 197,762,143	$ 151,343,283
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 4,598,534	$ 4,655,874
Revenue and severance tax payable	5,709,773	5,071,508
Accrued liabilities	8,451,655	1,649,994
Short-term notes payable	344,256	285,298
Asset retirement obligation - current	1,548,945	332,863
Total current liabilities	20,653,163	11,995,537
Long-term liabilities		
Asset retirement obligation	9,852,920	11,653,212
Long-term debt, net of discount of $2,115,195 and $4,140,662, respectively	125,384,805	131,200,209
Long-term debt related parties	-	605,428
Total long-term liabilities	135,237,725	143,458,849
Commitment and contingencies (see notes)		
Stockholders' equity (deficit):		
Common stock, $0.001 par value; 100,000,000 shares authorized 26,714,815 and 17,298,598 shares issued and outstanding at December	26,714	17,298

31, 2011 and 2010, respectively				
Additional paid-in capital		52,674,252		27,547,251
Retained earnings		(10,829,711)		(31,675,652)
Total stockholders' equity (deficit)		41,871,255		(4,111,103)
Total liabilities and stockholders' equity (deficit)	$	197,762,143	$	151,343,283

See notes to consolidated financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Year Ended December 31, 2011	2010
Revenues:		
Oil and gas revenues	$ 76,159,268	$ 52,734,207
Other revenues	4,774,882	2,284,008
Total revenues	80,934,150	55,018,215
Operating Expense:		
Lease operating expense	17,123,890	13,774,406
Workover expense	2,666,600	2,154,482
Exploration expense	596,065	1,921,943
Loss on plugging and abandonment	393,599	-
Dry hole costs	3,912,823	-
Depreciation, depletion and amortization	15,591,048	16,001,826
Impairment expense	641,791	-
Accretion expense	1,672,900	1,668,268
Gain on revision of asset retirement obligations	(303,633)	-
Gain on purchase price adjustment	(1,426,778)	-
Loss on settlement of accounts payable	-	990,786
General and administrative	8,704,536	8,476,124
Severance taxes	6,090,666	5,214,677
Total operating expenses	55,663,507	50,202,512
Operating income	25,270,643	4,815,703
Other income (expense):		
Commodity derivative expense, net	-	696,550
Interest income	248,935	115,350
Interest expense	(17,947,784)	(22,584,934)
Financing expense	(837,364)	-
Gain on extinguishment of debt	7,708,486	-
Total other expense	(10,827,727)	(21,773,034)
Net income (loss) before reorganization expenses and income taxes	14,442,916	(16,957,331)
Reorganization expenses	436,092	2,198,359
Net income (loss) before income taxes	14,006,824	(19,155,690)
Income tax provision (benefit)	(6,839,117)	285,838

Net income (loss)	$	20,845,941	$	(19,441,528)
Net income (loss) per share:				
Basic	$	0.95	$	(1.14)
Diluted	$	0.93	$	(1.14)
Weighted average number of common shares outstanding:				
Basic		21,975,480		16,996,166
Diluted		22,367,696		16,996,166

See notes to consolidated 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, 2009	16,690,292	$	16,690	$	19,887,814	$	(12,234,124)	$	7,670,380
Common stock issued to vendors	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)
Common stock options exercised	118,354		118		43,082		-		43,200
Common stock warrants exercised	1,043,748		1,044		(1,044)		-		-
Common stock issued in private placement	8,254,115		8,254		34,761,844		-		34,770,098

Fair value of warrants cancelled in extinguishment of debt	-		-		(10,620,000)		-		(10,620,000)
Stock-based employee compensation	-		-		943,119		-		943,119
Net income	-		-		-		20,845,941		20,845,941
Balance, December 31, 2011	26,714,815	$	26,714	$	52,674,252	$	(10,829,711)	$	41,871,255

See notes to consolidated financial statements.

Saratoga Resources, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2011	2010
Cash flows from operating activities:		
Net income (loss)	$ 20,845,941	$ (19,441,528)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depreciation, depletion and amortization	15,591,048	16,001,826
Impairment expense	641,791	-
Accretion expense	1,672,900	1,668,268
Amortization of debt issuance costs	526,891	526,397
Amortization of debt discount	1,702,018	1,965,993
Commodity derivative (income) expense	-	(473,962)
Dry hole costs	3,912,823	-
Stock-based compensation	943,119	2,570,144
Loss on settlement of accounts payable	-	990,786
Loss on plugging and abandonment	393,599	-
Gain on purchase price adjustment	(1,426,778)	-
Gain on revision of asset retirement obligations	(303,633)	-
Gain on extinguishment of debt	(7,708,486)	-
Deferred tax benefit	(6,547,962)	-
Changes in operating assets and liabilities:		
Accounts receivable	(1,499,920)	(1,660,182)
Prepaids and other	(150,688)	295,751
Accounts payable	(930,081)	(11,556,869)
Revenue and severance tax payable	641,443	(841,880)
Payments to settle asset retirement obligations	(1,148,655)	(153,655)
Accrued liabilities	6,689,890	8,742,502
Net cash provided (used) by operating activities	33,845,260	(1,366,409)
Cash flows from investing activities:		
Additions to oil and gas property	(29,347,415)	(9,417,471)
Additions to other property and equipment	(96,541)	(24,293)
Other assets	(1,028,048)	(767,381)
Net cash used by investing activities	(30,472,004)	(10,209,145)
Cash flows from financing activities:		
Issuance of warrants	-	100
Proceeds from issuance of common stock	14,813,298	-
Proceeds from short-term notes payable	1,649,068	1,260,276
Repayment of short-term notes payable	(1,590,110)	(1,389,234)
Repayment of debt borrowings	(268,224)	(5,500,000)
Repayment of debt borrowings - related party	(736,633)	-
Debt issuance costs of long term debt	(5,775,959)	-
Settlement of commodity hedges recorded in purchase accounting	-	38,913
Net cash provided (used) by financing activities	8,091,440	(5,589,945)

Net increase (decrease) in cash and cash equivalents		11,464,696		(17,165,499)
Cash and cash equivalents - beginning of period		4,409,984		21,575,483
Cash and cash equivalents - end of period	$	15,874,680	$	4,409,984
Supplemental disclosures of cash flow information:				
Cash paid for income taxes	$	130,000	$	902,491
Cash paid for interest		8,210,196		10,537,405
Non-cash investing and financing activities:				
Accounts payable for oil and gas additions	$	870,186	$	181,933
Accrued liabilities for oil and gas additions		124,712		280,556
Revisions to asset retirement obligations		1,542,172		281,389
Asset retirement obligations acquired		67,728		-
Accrued interest converted to long-term debt		-		30,811,843
Repayment of debt borrowing made directly to then existing lender by new lender and from proceeds from issuance of common stock		(145,231,776)		-
Proceeds from issuance of long-term debt paid directly to then existing lender		125,231,775		-
Proceeds from issuance of common stock paid directly to then existing lender		20,000,000		-
Debt issuance costs from issuance of warrants		-		4,099,016

See notes to consolidated financial statements.

Saratoga Resources, Inc.

NOTES TO THE CONSOLIDATED 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*.

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 natural gas have recently declined materially. Any continued and extended 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 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, 2011 and 2010 was immaterial.

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 $15.6 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 Shell Trading (US) Company and Shell Energy North America (US), L.P. (collectively Shell) accounted for 94% and 68% of our consolidated revenues in 2011 and 2010, respectively. We believe that the loss of Shell would not have a material adverse effect on us because alternative purchasers are readily available.

Other Revenue

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) during the 2011 period, refunds of severance taxes under a Louisiana incentive program for previously inactive wells and purchase price adjustments.

Cash and Cash Equivalents

For the purpose of the Statement of Cash Flows, we consider all highly liquid investments with an original 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, 2011 and 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. During the year ended December 31, 2011, Saratoga recorded an impairment expense of $641,791 relating to one property when development costs incurred during the year combined with the existing carrying value exceeded the fair value.

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 6 Oil and Gas Assets .

Depreciation of Other Property and Equipment

Furniture, fixtures, equipment, and other assets are depreciated using the straight-line method over the estimated useful lives of the assets. The estimated lives of these assets range 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 11 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 10 Common Stock).

Recently Issued Accounting Standards and Developments

In May 2011, the FASB issued Accounting Standards Update No. 2011 04: Fair Value Measurement (Topic 820) Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs . This accounting update clarifies application of fair value measurement and disclosure requirements and is effective for annual periods beginning after December 15, 2011. The Company is currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

In December 2011, the FASB issued Accounting Standards Update No. 2011 11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities . This accounting update requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The accounting update is effective for annual periods beginning on or after January 1, 2013. The Company is currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

NOTE 2. 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 and the Company exited from bankruptcy.

During the years ended December 31, 2011 and 2010, the Company incurred $436,092 and $2,198,359, respectively in reorganization costs.

NOTE 3. OTHER ASSETS

Other assets consist of the following:

	December 31,			
		2011		**2010**
Site specific trust accounts P&A escrow	$	4,629,816	$	2,533,348
Debt issuance cost, net		5,386,274		337,031
Restricted cash P&A bond		10,485,128		-
Bond		30,000		-
	$	20,531,218	$	2,870,379

Site Specific Trust Accounts P&A Escrow

The Company maintains 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 acquisition of oil and gas properties in certain fields. Changes in the escrow accounts reflect additional contributions during 2011. See Note 7 Asset Retirement Obligations .

During the year ended December 31, 2011, it was discovered that certain Site Specific Trust Accounts which were in existence at the time of acquisition by Saratoga had not been reflected in the original purchase price accounting. Accordingly, the assets, totaling $1,426,778, were reflected in the balance sheet during the current year and a corresponding gain on purchase price adjusted was recognized.

Debt Issuance Costs, Net

The Company capitalizes certain debt issuance costs and amortizes those costs as additional interest expense over the lives of the associated debt. Net debt issuance costs at December 31, 2010 reflected unamortized debt issuance costs associated with the previous debt facilities with Wayzata Investment Partners (Wayzata). Net debt issuance costs at December 31, 2011 reflect the issuance of the 2016 Notes in July 2011 and the retirement of the indebtedness to Wayzata. See Note 4 Debt .

Restricted Cash P&A Bond

Restricted Cash P&A Bond consists of cash collateral held in escrow to assure maintenance and administration of performance bonds which secures certain plugging and abandonment obligations imposed by state law. At December 31, 2010, the Company s obligations under the performance bond were secured by a letter of credit. In connection with the retirement of the debt to Wayzata in July 2011, the Company retired the letter of credit obligation and posted cash collateral in lieu of the letter of credit to secure the performance bond. See Note 7 Asset Retirement Obligations . The cash collateral is reflected as a long term asset to correspond with the expected timing of the related asset retirement obligation liability.

NOTE 4. DEBT

Long-term debt consists of the following:

	December 31, 2011		December 31, 2010	
12.5% Senior Secured Notes due 2016, net of unamortized discount of $2,115,195	$	125,384,805	$	-
11.25% Subordinated Secured Note due 2012, net of unamortized discount of $4,140,662		-		123,359,338
Senior secured credit facility, due 2012		-		7,840,871
	$	125,384,805	$	131,200,209

2016 Notes

In July 2011, the Company and the several wholly-owned subsidiaries of the Company (the Guarantors) entered into a Purchase Agreement (the Purchase Agreement) with Imperial Capital, LLC (the Initial Purchaser), relating to the issuance and sale of $127.5 million in aggregate principal amount of the Company s 12.5% Senior Secured Notes due 2016 (the 2016 Notes). The 2016 Notes were sold at 98.221% of par. The 2016 Notes were offered and sold in a transaction exempt from the registration requirements of the Securities Act. The 2016 Notes were resold to qualified institutional buyers in reliance on Rule 144A of the Securities Act and to persons outside of the U.S. pursuant to Regulation S.

The 2016 Notes were issued pursuant to an indenture, dated July 12, 2011 (the Indenture), among the Company, the Guarantors named therein and The Bank of New York Mellon Trust Company, N.A., as trustee (the Trustee) and as collateral agent (the Collateral Agent). The 2016 Notes are the senior secured obligations of the Company and are fully and unconditionally guaranteed on a senior secured basis by the Guarantors and will rank equally in right of payment with the Company s and the Guarantors existing and future senior indebtedness.

The 2016 Notes mature on July 1, 2016, and interest is payable on the 2016 Notes on January 1 and July 1 of each year, commencing January 1, 2012.

The Indenture includes customary events of default and places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of senior notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Company has the option to redeem all or a portion of the 2016 Notes at any time on or after January 1, 2014 at the redemption prices specified in the Indenture plus accrued and unpaid interest. The Company may also redeem the 2016 Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, plus accrued and unpaid interest, at any time prior to January 1, 2014. Within each twelve-month period commencing on July 12, 2012 and ending January 1, 2014, the Company may also redeem up to 10% of the aggregate principal amount of the 2016 Notes at a price equal to 106.25% of the principal amount thereof, plus accrued and unpaid interest. In addition, the Company may redeem up to 35% of the 2016 Notes prior to January 1, 2014 under certain circumstances with the net cash proceeds from certain equity offerings and at a price equal to 112.5% of the principal amount thereof, plus accrued and unpaid interest.

Retirement of Wayzata Debt

In July 2011, the Company utilized net proceeds from the issuance of long-term debt and common stock amounting to $125.2 million and $20.0 million, respectively, and $0.3 million in cash on hand to pay off the Wayzata debt of $145.5 million (including outstanding letter of credit obligations of $10.2 million).

In conjunction with the early payoff of amounts owing to Wayzata, the Second Warrants to purchase 2,000,000 shares issued to Wayzata, dated May 14, 2010, were cancelled. As a result of retirement of the Wayzata debt and cancellation of the Second Warrants, the Company wrote off $2.9 million of unamortized debt discount and debt issuance costs and reduced additional paid-in capital by $10.6 million (see Note 10 Common Stock Warrant Activity) resulting in a net gain on the extinguishment of debt totaling $7.7 million.

NOTE 5. COMMODITY DERIVATIVE INSTRUMENTS

The Company periodically uses 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, the Company 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.

As of December 31, 2011and 2010, the Company had no natural gas or crude oil derivative instruments outstanding and, during the year ended December 31, 2011, the Company had no gain or loss from commodity derivative instruments.

NOTE 6. OIL AND GAS ASSETS

Property and equipment consisted of the following:

	December 31,			
		2011		2010
Oil and gas properties (proved):				
Gross oil and gas properties (proved)	$	196,101,827	$	170,870,775
Accumulated depreciation, depletion, amortization and impairment		(53,345,814)		(37,242,966)
Net oil and gas properties (proved)		142,756,013		133,627,809
Other property and equipment		658,113		561,572
Accumulated depreciation and amortization		(485,006)		(355,014)
Net other property and equipment		173,107		206,558
Net property and equipment	$	142,929,120	$	133,834,367

NOTE 7. ASSET RETIREMENT OBLIGATIONS

The Company accounts for plugging and abandonment costs in accordance with FASB ASC 410-20, Accounting for Asset Retirement Obligations.

The Company maintains 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 acquisition of oil and gas properties in certain fields.

At December 31, 2011 and 2010, the amount of the escrow account totaled $4.6 million and $2.5 million, respectively and is shown as other assets on the Company s balance sheet. See Note 3 Other Assets .

During the year ended December 31, 2011, downward revisions in the asset retirement obligations relating to one property exceeded the carrying amount of the property. According, the excess amount, which was $303,633, was recognized as a gain during the year.

During the year ended December 31, 2011, plugging and abandonment costs related to one property exceed the amount reflected in the asset retirement obligation liability. Accordingly, the excess amount, which was $393,593, was recognized as a loss during the year.

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

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
Accretion expense	1,672,900
Additions	67,728
Revisions	(1,542,172)
Settlements	(782,666)
Balance at December 31, 2011	$ 11,401,865

NOTE 8. RELATED PARTY TRANSACTIONS

Pursuant to our Plan of Reorganization, notes payable to the Company s Chief Executive Officer and President, in the aggregate amount of $736,633 were repaid in November 2011 upon prior satisfaction of all claims under the Plan of Reorganization, and following approval of the bankruptcy court.

The Company has $10,159,128 cash collateral held in escrow by Macquarie affiliates to assure maintenance and administration of performance bonds which secure certain plugging and abandonment obligations imposed by state law (see Note 3 Other Assets). Macquarie affiliates own greater than 10% of the outstanding common stock of Saratoga.

NOTE 9. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

We have commitments under non-cancellable operating lease agreements for our office in Houston, Texas

Rent expense with respect to our lease commitments for office space for the year ended December 31, 2011 and 2010 was $226,258 and $210,349, 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 in letters of credit. The letters of credit are secured by cash collateral.

At December 31, 2011, total minimum commitments from debt, long-term non-cancelable operating leases, asset retirement obligations and other purchase obligations are as follows:

	Payments due by period				
	Total	**2012**	**2013 2014**	**2015 2016**	**Thereafter**
Debt	$ 127,500,000	$ -	$ -	$ 127,500,000	$ -
Operating leases	142,356	84,924	57,432	-	-
Capital leases	-	-	-	-	-
Asset retirement obligations	45,798,500	1,987,500	-	3,525,000	40,286,000
Total	$ 173,440,856	$ 2,072,424	$ 57,432	$ 131,025,000	$ 40,286,000

Contingencies

From time to time the Company may become involved in litigation in the ordinary course of business. At December 31, 2011, the Company s management was not aware, and as of the date of this report is not aware, other than as described below, of any such litigation that could have a material adverse effect on its results of operations, cash flows or financial condition.

In December 2009, the Parish of Plaquemines, State of Louisiana, filed supplemental assessments against multiple oil and gas companies, including Saratoga, for allegedly omitting or undervaluing oil producing assets on the annual self-reporting tax renditions used in calculating ad valorem taxes. In short, the difference between what was reported by the oil and gas companies and what the assessor taxed boiled down to how depreciation of the oil and gas related equipment was calculated and how certain equipment was classified. The amount alleged to be due by Saratoga for the years 2006, 2007, and 2008 is $1.3 million in Parish taxes. Also at issue are the increased assessment valuations for the years 2009, 2010, and 2011 brought by the Parish under the same theory. 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 for the Parish of Plaquemines, Louisiana, and, as to certain issues relating to such claim, in a number of administrative proceedings before the Louisiana Tax Commission. We believe the additional assessment is in error and intend to vigorously defend this action. Saratoga has paid $0.7 million of the additional assessments and has included the remaining $0.6 million of the $1.3 million total in accounts payable as of December 31, 2011 pending resolution of the dispute.

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, 2011, 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.

Registration Rights Agreements

In connection with the issuance and sale of the 2016 Notes, the Company and the Guarantors entered into a registration rights agreement (the Registration Rights Agreement) with the Initial Purchaser. Pursuant to the Registration Rights Agreement, the Company and the Guarantors agreed to file a registration statement with the Securities and Exchange Commission so that holders of the 2016 Notes can exchange the 2016 Notes for registered notes that have substantially identical terms as the 2016 Notes. In addition, the Company and the Guarantors agreed to exchange the guarantee related to the 2016 Notes for a registered guarantee having substantially the same terms as the original guarantee. The Company and the Guarantors agreed to use their reasonable best efforts to cause a registration statement with respect to the exchange to be filed within 90 days after the issuance of the 2016 Notes and declared effective under the Securities Act within 180 days after the issuance of the 2016 Notes. In the event of a failure to comply with the obligations to register the 2016 Notes within the specified time periods or to continue to maintain the effectiveness of the registration (a Registration Default), the interest rate on the 2016 Notes will be increased by 0.25% for each 90 days that such Registration Default continues, provided that the increase in interest rate shall in no event exceed an aggregate of 1.0% and provided, further, that upon cure of any such Registration Default the interest rate on the 2016 Notes will be reduced to its original rate. A registration statement relating to the exchange of the 2016 Notes was filed on September 26, 2011 and was declared effective by the Securities and Exchange Commission on October 19, 2011. Following the effectiveness of the registration statement, the Company completed an exchange of registered notes for the unregistered 2016 Notes.

In connection with the July 2011 issuance and sale of shares, the Company entered into a registration rights agreement (the Equity Registration Rights Agreement) with the purchasers of the shares. Pursuant to the Equity Registration Rights Agreement, the holders of a majority of the shares will have a demand registration right pursuant to which the Company may be required to file with the Securities and Exchange Commission one or more registration statements covering the resale of the shares. Additionally, the Equity Registration Rights Agreement provides piggyback registration rights to the holders of the shares pursuant to which the holders are entitled to notice of the filing of certain registration statements by the Company and inclusion of some or all of the shares in any such registration statements.

NOTE 10. 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,	
2011	2010
Weighted	Weighted

		Income	Average Common Shares Outstanding		Per Share		Loss	Average Common Shares Outstanding		Per Share
Basic:										
Income (loss) attributable to common stock	$	20,845,941	21,975,480	$	0.95	$	(19,441,528)	16,996,166	$	(1.14)
Effective of Dilutive Securities:										
Stock options and warrants		-	392,216				-	-		
Diluted:										
Income (loss) attributable to common stock, including assumed conversions	$	20,845,941	22,367,696	$	0.93	$	(19,441,528)	16,996,166	$	(1.14)

Potentially dilutive securities excluded from the computation of weighted average diluted shares of common stock because the impact of these securities were antidilutive totaled 4,198,016 for the year ended December 31, 2010.

Common Stock Activity

Pursuant to the terms of the Company s plan of reorganization, in May 2010, the Company issued an aggregate of 483,306 shares of common stock pro rata among oil lien claim creditors, other secured creditors and unsecured creditors. The Company recorded a loss on settlement of accounts payable in the income statement for $990,785 for the fair value of the common stock.

In January 2011, the Company received gross proceeds of $9,000 for 25,000 stock options exercised at $0.36 a share.

In April 2011, the Company sold to U.S. and non-U.S. accredited investors, in a private placement, an aggregate of 2,481,316 shares of common stock and warrants to purchase 1,240,658 shares of common stock. The shares and warrants were offered in units of two shares and one warrant at $6.00 per unit for aggregate gross proceeds of $7,443,948. Pursuant to the offering, the Company issued 84,600 shares of common stock to a placement agent with respect to units sold to non-U.S. investors.

In July 2011, the Company sold to U.S. and non-U.S. accredited and institutional investors, in a private placement, an aggregate of 5,650,000 shares of common stock at a price of $5.00 per share. Net proceeds from the sale of shares were approximately $27.3 million, of which $20.0 million was deposited directly into a third party escrow account to be applied to the retirement of indebtedness to Wayzata. Pursuant to the offering, the Company issued 38,200 shares of common stock to a placement agent with respect to shares sold to non-U.S. investors.

In November and December 2011, the Company received gross proceeds of $34,200 for 20,000 stock options exercised at $1.71 a share.

During the year ended December 31, 2011, the Company issued an aggregate of 1,043,748 shares of common stock pursuant to the cashless exercise of warrants. See -Warrant Activity below.

During the year ended December 31, 2011, the Company issued an aggregate of 73,354 shares of common stock pursuant to the cashless exercise of stock options. See -Stock Option Activity below.

Stock-Based Compensation

The Company periodically grants restricted stock and stock options to employees, directors and consultants. The Company is required to make estimates of the fair value of the related instruments when granted and recognize expense over the period benefited, usually the vesting period.

In September 2011, the Company s board of directors adopted the Saratoga Resources, Inc. 2011 Omnibus Equity Plan (the 2011 Plan). The 2011 Plan reserves a total of 3,000,000 shares 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 agreements. The 2011 Plan is, and grants thereunder are, subject to approval by the Company s stockholders.

In conjunction with the adoption of the 2011 Plan, the Company s board of directors approved the termination of the Saratoga Resources, Inc. 2008 Long-term Incentive Plan (the 2008 Plan) and the Saratoga Resources, Inc. 2006

Employee and Consultant Stock Plan (the 2006 Plan). As of December 31, 2011, no awards were outstanding under the 2008 Plan or the 2006 Plan.

Stock Option Activity

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.

In March 2011, the Company s board of directors approved stock option grants to purchase an aggregate of 105,000 shares of common stock to the Company s non-employee directors, including options granted to a newly appointed director. 70,000 of the options are exercisable at $3.05 per share and 35,000 of the options are exercisable at $2.80 per share. The options vested 50% on the respective grant dates and vest as to the remaining 50% one year from the grant date. The options are exercisable for a term of seven years. The grant date value of the aggregate 105,000 options was $0.3 million. The options were valued using the Black-Scholes model with the following assumptions: 346% - 347% volatility; 3.75 year estimated life; zero dividends; 1.394% discount rate as to 35,000 options and 1.64% discount rate as to 70,000 options; quoted stock price and exercise price of $2.80 per share as to 35,000 options and $3.05 per shares as to 70,000 options.

In April 2011, the Company s board of directors approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to a non-executive employee. The options are exercisable for a term of ten years at $2.75 per share and vest 1/3 on each of the first three anniversaries of the grant date. The grant date value of the options was $82,500. The options were valued using the Black-Scholes model with the following assumptions: 320% volatility; 6.0 year estimated life; zero dividends; 2.47% discount rate; and, quoted stock price and exercise price of $2.75.

In September 2011, the Company s board of directors approved a stock option grant to purchase an aggregate of 50,000 shares of common stock to a newly hired non-executive employee. The options are exercisable for a term of seven years at $5.63 per share and vest as to 16,000 shares on the first anniversary of the grant date and as to 17,000 shares on each of the second and third anniversaries of the grant date. The grant date value of the options was $281,500. The options were valued using the Black-Scholes model with the following assumptions: 318% volatility; 6.0 year estimated life; zero dividends; 1.19% discount rate; and, quoted stock price and exercise price of $5.63.

In October 2011, the Company s board of directors approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to a newly hired non-executive employee. The options are exercisable for a term of seven years at $5.11 per share and vest as to 10,000 shares on each of the first, second and third anniversaries of the grant date. The grant date value of the options was $153,300. The options were valued using the Black-Scholes model with the following assumptions: 309% volatility; 4.5 year estimated life; zero dividends; 0.96% discount rate; and, quoted stock price and exercise price of $5.11.

In October 2011, the Company s board of directors approved a stock option grant to purchase an aggregate of 150,000 shares of common stock to a newly hired executive employee. The options are exercisable for a term of seven years at $4.59 per share and vest as to 50,000 shares on each of the first, second and third anniversaries of the grant date. The grant date value of the options was $687,750. The options were valued using the Black-Scholes model with the following assumptions: 307% volatility; 4.5 year estimated life; zero dividends; 0.99% discount rate; and, quoted stock price and exercise price of $4.59.

In November 2011, the Company s board of directors approved a stock option grant to purchase an aggregate of 30,000 shares of common stock to a newly hired executive employee. The options are exercisable for a term of seven years at $4.62 per share and vest as to 10,000 shares on each of the first, second and third anniversaries of the grant date. The grant date value of the options was $138,600. The options were valued using the Black-Scholes model with the following assumptions: 305% volatility; 4.5 year estimated life; zero dividends; 0.91% discount rate; and, quoted stock price and exercise price of $4.62.

In December 2011, a former employee exercised stock options to purchase 150,000 shares of common stock at $3.00 per share and stock options to purchase 33,333 shares of common stock at $1.71 per share. The stock options were exercised pursuant to cashless exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 73,354 shares of common stock pursuant to the exercise of the stock options.

During the year ended December 31, 2011, stock options to purchase 45,000 shares of common stock at prices ranging from $0.36 to $1.71 were exercised for cash proceeds totaling $43,200.

Stock based compensation expense attributable to common shares and grants of options was $943,119 and $2,570,145 during the years ended December 31, 2011 and 2010, respectively. The unamortized amount of stock-based compensation that had not been recorded was $1,226,285 and $700,755 as of December 31, 2011 and 2010, respectively.

The following table presents the options outstanding at December 31, 2011:

	Number of Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Grant Date Fair Value per Share	Weighted Average Remaining Contractual Life (in Years)	Aggregate Intrinsic Value [(1)]
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
Granted	395,000	4.19	4.19	7.2	1,228,350
Exercised	(228,333)	2.41	2.36	-	-
Forfeited	(201,667)	1.71	1.48	-	-
Outstanding at December 31, 2011	982,500	3.09	3.07	7.6	4,133,025
Exercisable at December 31, 2011	563,333	$ 2.53	$ 2.48	7.5	$ 2,689,806

(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, 2011, the last reported sales price of our common stock on the NYSE AMEX was $7.30 per share.

The following table summarizes information about stock options outstanding and exercisable at December 31, 2011:

Options Outstanding and Exercisable			
Exercise Price	**Number of Shares Underlying Options**	**Weighted Average Exercise Price per Share**	**Weighted Average Remaining Contractual Life (in Years)**
$ 0.36	50,000	$ 0.36	7.2
1.39	10,000	1.39	3.7
1.53	38,333	1.53	8.5
1.71	47,500	1.71	3.5
2.80	17,500	2.80	6.2
3.00	365,000	3.00	8.3
3.05	35,000	3.05	6.2
	563,333	$ 2.53	7.5

Warrant Activity

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 and are vested immediately. The warrants were valued using the Black-Scholes 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.

Pursuant to the terms of the Company s plan of reorganization, in May 2010, the Company issued to Wayzata Investment Partners (Wayzata) a warrant (the Second Warrants) to purchase 2,000,000 shares of common stock. The warrants vested as to 111,111 shares on exit from bankruptcy (May 14, 2010) and, thereafter, vested as to 111,111 shares per month until April 2012. The fair value of the warrants of $4,099,116 was recorded as a debt discount to long-term debt. The warrants were exercisable at $0.01 per share for a term of five years. The warrants were valued using the Black-Scholes model with the following assumptions: $2.05 quoted stock price; $0.01 exercise price; 397% volatility; 5 year estimated life; zero dividends; 0.85% discount rate.

In April 2011, the Company entered into a Warrant Termination Agreement with Wayzata. Under the terms of the Warrant Termination Agreement, Wayzata agreed, subject to the Company s repayment by July 14, 2011 of all amounts owing under the existing credit facilities with Wayzata, to the cancellation of Second Warrants to purchase up to 2,000,000 shares of common stock. Upon closing of the July 2011 note placement and retirement of all amounts owing to Wayzata, in July 2011, the Second Warrants were cancelled resulting in a gain of $10.6 million relating to the unamortized balance of the fair value of the warrants (see Note 4 Debt Retirement of the Wayzata Debt).

Pursuant to the April 2011 private placement of units of common stock and warrants, the Company issued warrants to purchase 1,240,658 shares of common stock. The warrants are exercisable for two years to purchase shares of common stock at $5.00 per share. In connection with the private placement, the company issued to a placement agent a warrant to purchase 42,300 shares of common stock on identical terms to the warrants sold in the private placement.

In September 2011, Wayzata exercised a warrant, originally issued in July 2008, to purchase 805,516 shares of common stock at $0.01 per share. The warrant was exercised pursuant to a cashless exercise provision wherein the intrinsic value of the warrant was delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 803,764 shares of common stock pursuant to the exercise of the warrant.

In December 2011, a service provider exercised a warrant, originally issued in May 2008, to purchase 250,000 shares of common stock at $0.25 per share. The warrant was exercised pursuant to a cashless exercise provision wherein the intrinsic value of the warrant was delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 239,984 shares of common stock pursuant to the exercise of the warrant.

The following table presents the warrants outstanding at December 31, 2011:

	Number of Shares Underlying Warrants	**Weighted Average Exercise Price per Share**	**Weighted Average Grant Date Fair Value per Share**	**Weighted Average Remaining Contractual Life (in Years)**	**Aggregate Intrinsic Value [1]**
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	-	-	-	-	-
	3,130,516	$ 0.07	$ 2.03	3.7	$ 6,850,506

Outstanding at December 31, 2010							
Granted	1,282,958		5.00		2.66	1.4	2,950,803
Exercised	(1,055,516)		0.07		2.01	-	-
Forfeited	(2,000,000)		0.01		2.05	-	-
Outstanding at December 31, 2011	1,357,958	$	4.82	$	2.61	1.4 $	3,365,703
Exercisable at December 31, 2011	1,357,958	$	4.82	$	2.61	1.4 $	3,365,703

(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, 2011, the last reported sales price of our common stock on the NYSE AMEX was $7.30 per share.

The following table summarizes information about stock warrants outstanding and exercisable at December 31, 2011:

Warrants Outstanding and Exercisable					
	Exercise Price	**Number of Shares Underlying Warrants**		**Weighted Average Exercise Price per Share**	**Weighted Average Remaining Contractual Life (in Years)**
$	0.17	30,000	$	0.17	1.4
	1.50	5,000		1.50	1.8
	3.00	40,000		3.00	3.3
	5.00	1,282,958		5.00	1.3
		1,357,958	$	4.82	1.4

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NOTE 11. 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, 2011 and 2010 consisted of the following:

		2011		2010
Current:				
Federal	$	-	$	-
State		(291,155)		285,838
		(291,155)		285,838
Deferred:				
Federal		(6,547,962)		-
State		-		-
		(6,547,962)		-
Total tax provision (benefit)	$	(6,839,117)	$	285,838

The U.S. federal statutory income tax rate is reconciled to the effective rate at December 31, 2011 and 2010 as follows:

	2011	2010
Income tax expense at U.S. federal statutory rate	35.0%	35.0%
Valuation allowance	(69.9)%	(31.0)%
State and local income taxes, net of federal income tax benefit	3.3%	3.3%
Permanent differences	(20.1)%	(6.9)%
Temporary differences	2.6%	(1.9)%
Effective tax rate	(49.1)%	(1.5)%

The components of the net deferred tax assets (liabilities) at December 31, 2011 and 2010 are as follows:

	2011	2010
Deferred tax asset		
Net operating loss	$ 8,152,044	$ 10,236,257
Stock-based compensation	1,918,506	1,557,763
Debt issuance cost (amortization)	1,309,041	456,484
Depreciation and amortization	8,971	18,582
Capital loss carryover	103,752	103,752
Charitable contributions	7,048	7,048
Total deferred tax assets	11,499,362	12,379,886
Deferred tax liability		
Depletion on oil and gas properties	4,951,400	2,386,333
Total deferred tax liabilities	4,951,400	2,386,333
Less: valuation allowance	-	(9,993,553)
Deferred tax asset (liability)	$ 6,547,962	$ -

At December 31, 2011, we had $21.3 million of federal net operating loss, or NOL, carryforwards; the federal NOL carryforwards have expiration dates through the year 2030.

We recognize the expected future tax benefit from deferred tax assets when the tax benefit is considered to be more likely than not of being realized. Otherwise, a valuation allowance is applied against deferred tax assets reducing the value of such assets. Assessing the recoverability of deferred tax assets requires management to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecasted income from operations and the application of existing tax laws in each jurisdiction. Oil and gas price estimates are a key component used in the determination of our ability to realize the expected future benefit of our deferred tax assets. To the extent that future taxable income differs significantly from estimates as a result of a decline in oil and gas prices or other factors, our ability to realize the deferred tax assets could be impacted. Additionally, significant future issuances of common stock or common stock equivalents could limit our ability to utilize our net operating loss carryforwards pursuant to Section 382 of the Internal Revenue Code. Future changes in tax law or changes in ownership structure could limit our ability to utilize our recorded tax assets. As of December 31, 2011, we removed substantially all deferred tax valuation allowances related to net operating loss carryforwards, and our current and non-current deferred tax asset balances were $1.4 million and $5.1 million, respectively. Accordingly, during the year ended December 31, 2011 Saratoga recognized an income tax benefit of $6.8 million.

NOTE 12. SUPPLEMENTAL OIL AND GAS DISCLOSURES - UNAUDITED

Capitalized costs for our oil and gas producing activities consisted of the following at December 31, 2011 and 2010:

		2011		**2010**
Proved properties	$	196,101,827	$	170,808,035
Unproved properties		-		62,740
		196,101,827		170,870,775
Accumulated depreciation, depletion, amortization and impairment		(53,345,814)		(37,242,966)
Net capitalized costs	$	142,756,013	$	133,627,809

Costs incurred for oil and gas property acquisitions, exploration and development for the years ended December 31, 2011 and 2010 are as follows:

		2011		**2010**
Acquisitions of properties:				
Proved	$	569,425	$	99,015
Unproved		-		44,261
Exploration and dry hole costs		4,508,888		1,590,029
Development		25,898,062		9,736,684
	$	30,976,375	$	11,469,989

The following table sets forth the consolidated results of operations for the years ended December 31, 2011 and 2010:

	2011	2010
Oil and gas sales	76,159,268	52,734,207
Production costs	(17,123,890)	(13,774,406)
Workover expense	(2,666,600)	(2,154,482)
Exploration expense	(596,065)	(1,921,943)
Loss on plugging and abandonment	(393,599)	-
Dry hole costs	(3,912,823)	-
Depreciation, depletion, amortization and impairment	(16,232,839)	(16,001,826)
Accretion expense	(1,672,900)	(1,668,268)
Gain on revision of asset retirement obligations	303,633	-
Severance taxes	(6,090,666)	(5,214,677)
Income before income taxes	27,773,519	11,998,605
Income tax benefit (provision)	6,839,117	(285,838)
Results of operations for and gas producing activities (excluding Corporate overhead and financing costs)	$ 34,612,636	$ 11,712,767

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, 2011:

	Gas (Mcf)	**Oil (Bbls)**	**Boe**
For the year ended December 31, 2009			
Beginning of year	49,627,000	4,515,000	12,786,167
Acquisition of reserves	-	-	-
Discoveries and 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 and 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
For the year ended December 31, 2011			
Beginning of year	60,875,600	7,878,400	18,024,335
Acquisition of reserves	1,717,000	172,900	459,067
Discoveries and extensions	1,456,000	18,400	261,067
Improved recovery			
Revisions	3,951,000	511,200	1,169,700
Production	(2,038,000)	(605,900)	(945,567)
End of year	65,961,600	7,975,000	18,968,602
Proved developed reserves			
Beginning of year	5,112,400	2,656,600	3,508,667
End of year	10,101,000	2,580,600	4,264,100

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)	**2011**	**2010**	**2009**
Future cash inflows	$ 1,210,125	$ 934,061	$ 696,034
Future production costs	(281,429)	(209,593)	(185,139)
Future development costs	(226,552)	(239,510)	(165,960)
Future net cash flows before income taxes	702,144	484,958	344,935
Future income tax expense	(207,555)	(130,490)	(121,711)
Future net cash flows before 10% discount	494,589	354,468	223,224
10% annual discount for estimating timing of cash flows	(163,705)	(118,811)	(77,638)
Standardized measure of discounted future net cash flows	$ 330,884	$ 235,657	$ 145,586

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)	**2011**	**2010**	**2009**
Beginning of year	$ 235,657	$ 145,586	$ 97,994
Sales of oil and gas produced, net of production costs	(49,945)	(31,270)	(20,705)
Net change in prices and production costs	108,942	135,389	29,321
Extension, discoveries, and improved recovery, less related costs	16,128	-	-
Development costs incurred during the year	7,088	-	6,634
Net change in estimated future development costs	7,493	(49,840)	(47,115)
Revisions of previous quantity estimates	37,107	13,943	90,937
Net change from acquisitions of minerals in place	16,861	3,689	-
Net change in income taxes	(53,119)	(1,919)	(27,907)
Accretion of discount	31,597	22,398	14,695
Changes in timing and other	(26,925)	(2,319)	1,732
End of year	$ 330,884	$ 235,657	$ 145,586

NOTE 13. SUBSEQUENT EVENTS

In January and February 2012, the Company received gross proceeds of $51,250 for 30,000 stock options exercised at $1.71 a share.

In January 2012, an employee exercised stock options to purchase 10,000 shares of common stock at $3.00 per share. The stock options were exercised pursuant to cashless exercise provisions wherein the intrinsic value of the stock options were delivered to the Company in lieu of cash payment of the exercise price and, as a result, the Company issued an aggregate of 5,275 shares of common stock pursuant to the exercise of the stock options.

In January 2012, the Company received gross proceeds of $2,500,000 for warrants to purchase 500,000 shares of common stock at $5.00 per share.