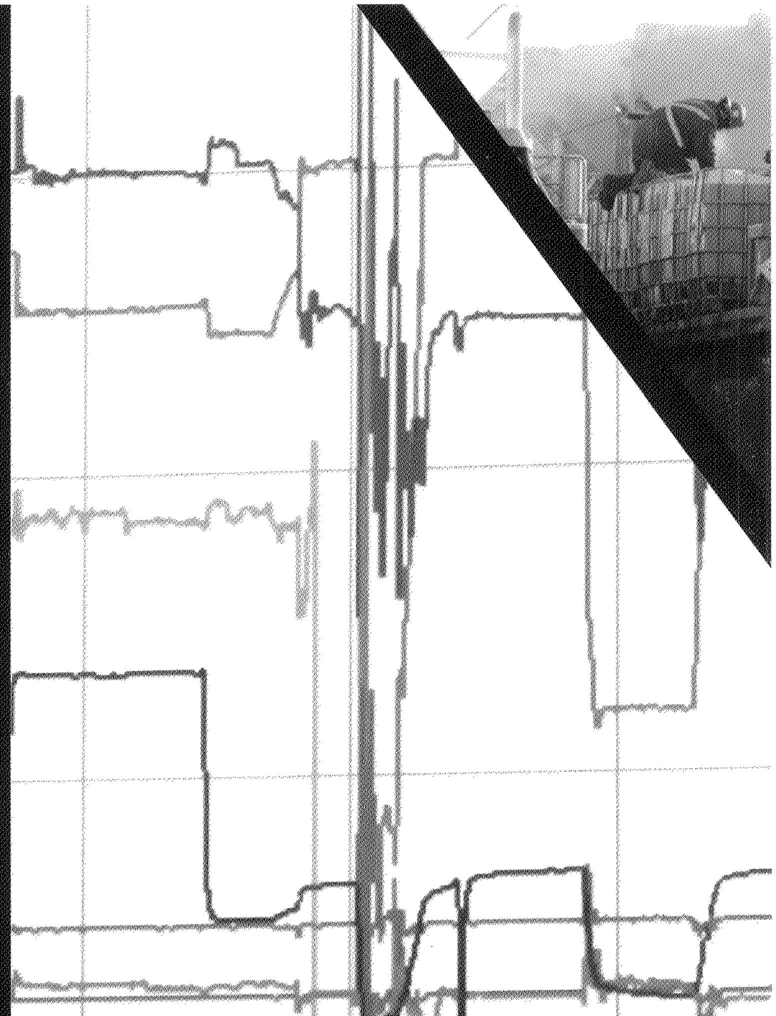
ANNUAL REPORT 2010



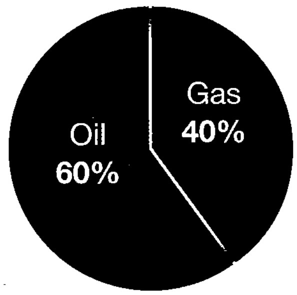
GeoResources, Inc.

Oil & Gas Exploration and Production

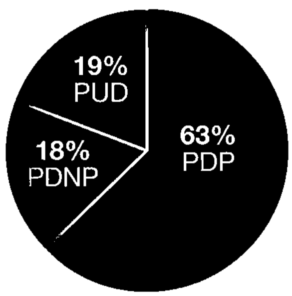
About GeoResources, Inc.

Proved Reserve Profile*

Reserve %

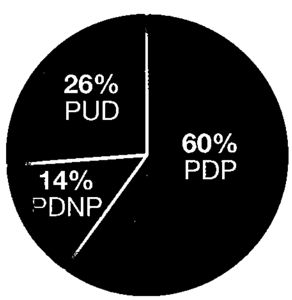


Present Value



$378.3 Million
PV-10 Value

Reserve Quantities



24.0 MMboe

* As of December 31, 2010, excludes interests in affiliated partnerships.

GeoResources, Inc. owns and operates producing oil and gas properties located primarily in the Southwest, Gulf Coast and the Williston Basin regions of North America, and conducts oil and gas exploration, development and production operations in these areas.

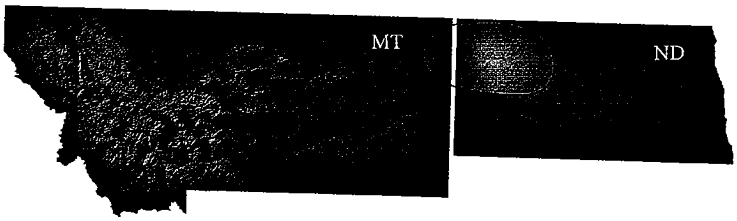
Our business strategy is intended to preserve shareholder value while exposing the Company to significant growth opportunities.

Our strategy includes the following:

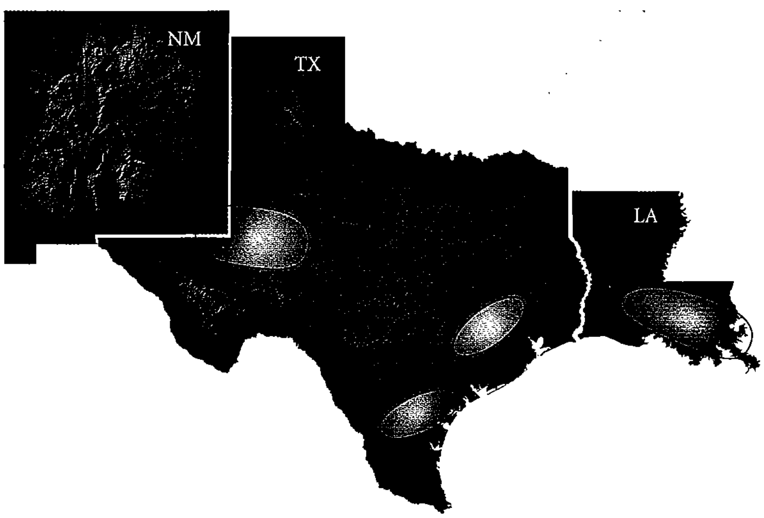
- Expanding acreage and prospect inventory;
- Acquiring additional oil and gas reserves through asset or corporate acquisitions or mergers; and
- Growing reserves and production through development, exploitation and exploration activities.

GeoResources, Inc. common stock trades on the NASDAQ Global Market under the ticker GEOI.

Focus Areas



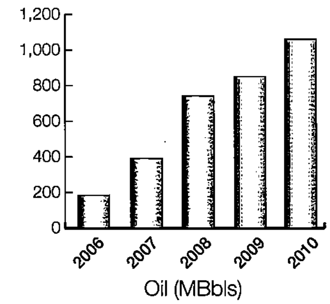
- Bakken and Williston Basin Oil
- 45,000 Net Bakken Acres
- 32% of Total Production
- 33% of Proved Reserves

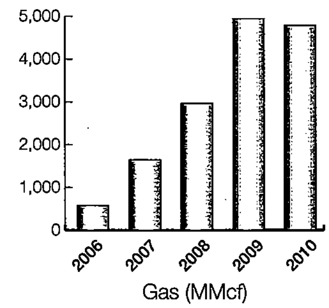


- Diversified Exploration and Development Projects
- 23,000 Net Eagle Ford Acres
- 68% of Total Production
- 67% of Proved Reserves

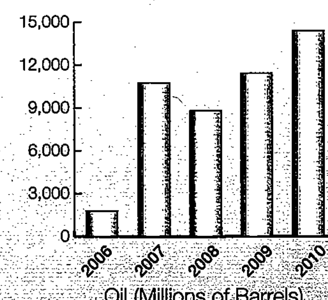
*See our 2010 Form 10K for description of noteworthy properties.

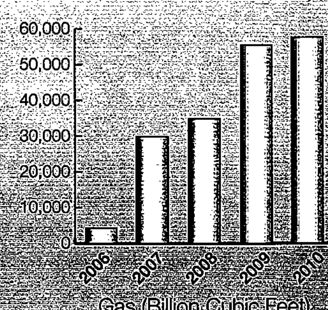
Annual Production





Proved Reserves at Year End





To Our Shareholders

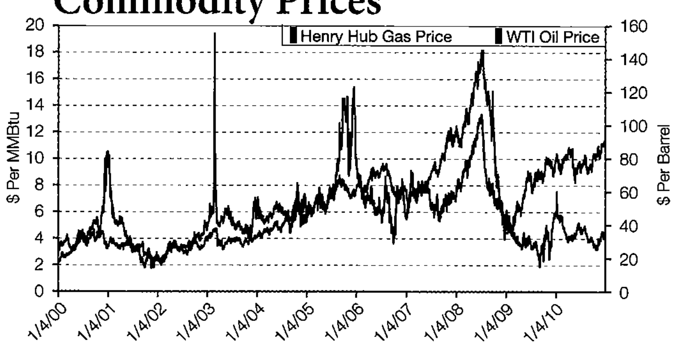
During 2010, the Company achieved several milestones. Our reported revenues exceeded $100 million and our reported EBITDAX, production and proved reserves also reached new highs. We achieved these results even though the industry was challenged by low natural gas prices and significant competition for services which resulted in delays in placing new wells on production.

Before I address our financial results and operations, I will reiterate our business strategy for the benefit of our long-term shareholders, as well as new and prospective shareholders. Our strategy is focused on building a diversified portfolio of properties in areas we are familiar with and includes acquisition, exploration and development activities in each of these areas. We believe that our management and operational personnel have specific technical and operating expertise in our focus areas that allows us to find and develop oil and gas in an industry-leading cost-effective manner. This approach also allows us to "spread the risk" and to take advantage of regional differences in commodity pricing, costs and available services and infrastructure. Your management team has successfully executed this strategy in several prior entities, and I believe we are validating our strategy once again with GeoResources. We have achieved the impressive financial and operating results presented in this annual report in less than four years. We believe our business approach is well-suited for the profitable growth of an oil and gas company because:

- Our strategy allows us to manage the multiple risks of oil and gas operations while providing shareholders with significant exposure to growth and upside; and
- Our strategy gives us "staying power," which we have always believed is essential to mitigate the adverse impacts of fluctuating and volatile commodity prices; and
- Our strategy enables GeoResources to withstand adverse changes in financial markets.

To address our operating results and financial position, for the year ended December 31, 2010, we achieved revenues of $107.0 million, net income of $23.3 million and EBITDAX of $69.1 million. Our average realized crude oil price was $70.33 per barrel, and our average realized natural gas price was $5.30 per mcf. Our production for the year was 1,060 Mbbls of crude oil and 4.8 Bcf of natural gas, or 1.9 million barrels of oil equivalent (Mmboe). Our proved reserves have increased to 24.0 Mmboe, and are comprised of 60% oil.

Commodity Prices



In January 2011, we completed an equity issuance and were pleased with the market's acceptance of our offering. Our intent was to raise capital to accelerate the development of our acreage positions in the Bakken and Eagle Ford trends and also to pursue additional acquisitions in our focus areas. In addition, we believed an offering would lead to increased trading volume and liquidity in our shares and therefore attract additional shareholders. Further, we repaid all $85 million of our outstanding bank debt and started 2011 with significant cash flow, $45 million cash and $145 million of debt availability. I believe we are well-positioned to continue our profitable growth in 2011 and beyond.

Operations

During 2010, we continued our leasing efforts in the Bakken trend of the Williston Basin and established a significant acreage position in the Eagle Ford trend of Southeast Texas. These accomplishments resulted in increasing our Bakken position to 45,000 net acres and adding to our current Eagle Ford acreage, now 23,000 net acres. These positions provide us with a multi-year development drilling inventory which should drive significant production and cash flow growth over the next several years. In both of these areas we brought in joint venture partners on a promoted basis for some of the acreage while retaining operational control of the projects. We believe this approach is beneficial to shareholders as it allows us to control and develop larger acreage positions and provides an economic enhancement on our projects' rates of returns. Importantly, we commenced drilling our operated Bakken acreage in the fourth quarter of 2010 and our Eagle Ford acreage in the first quarter of 2011.

As previously mentioned, a fundamental part of our business strategy is diversification. As significant shareholders, your management does not want "all of our eggs in one basket." Therefore, we eased up on our Bakken leasing in 2010 and focused on drilling and production by securing a drilling rig and services to initiate development of our operated acreage. We concurrently started leasing in the Eagle Ford trend, promoted a partner into the venture and initiated drilling in that play in early 2011. At present, we are operating one rig in each project area and plan to bring on additional rigs, subject to availability, over the course of 2011 and 2012.

In early 2010 we suspended our successful drilling program targeting the Austin Chalk formation in Giddings Field, Texas because of low natural gas prices. At present, we control 29,000 net acres, operate 68 producing wells with working interests ranging from 37% to 53%, and have identified 20 additional prospective Austin Chalk drilling locations. At current prices and based on operating results to date, the Austin Chalk natural gas locations generate a reasonable rate of return. However, because the vast majority of this acreage is held by producing operations and/or has long-term leases, we chose to focus on oil-weighted operations in the Bakken and Eagle Ford plays in 2010. In the Austin Chalk we are selectively increasing our lease positions because we believe the acreage is prospective for the Yegua, Georgetown and possibly the Eagle Ford shale formations. In 2011, we have budgeted for three gross wells in our Giddings project with one well expected to be liquids rich. The other two wells are in a gas drilling area and whether or not we drill them will be dependent on natural gas prices. Because our natural gas wells are naturally fractured and typically have very high initial flow rates, a modest increase in natural gas prices can significantly increase projected rates of return. Therefore, under certain circumstances, we could consider drilling additional Austin Chalk wells, particularly these locations where we could capture and hold acreage that has additional drilling potential.

Finally, I want to stress that your management team owns significant shares; we are not simply hired guns. We are driven by rates of return, cash flow and profitability. We continue to work very hard to capitalize on the Company's opportunities and overcome the numerous challenges facing our industry, including the availability of rigs and services at reasonable costs.

Thanks Again

I would like to thank all those who have assisted our corporate efforts, including our Board members, officers and employees. Our progress is a direct result of their hard work and dedication. In addition, I want to thank our shareholders for their support, including both our long-term core shareholders and those who have joined us recently. I am thankful to all!

Frank A. Lodzinski

Frank A. Lodzinski
Chairman and Chief Executive Officer
March 31, 2011

Operational & Financial Highlights

(in thousands, except as otherwise indicated)	2010	2009	2008	2007	2006
Proved Reserves Year-End [A]					
Oil (MBbls)	14,393	11,419	8,793	10,744	1,777
Natural Gas (MMcf)	57,554	55,436	34,796	29,810	4,218
Barrels of Oil Equivalent (MBoe)	23,985	20,659	14,592	15,712	2,480
Percent Developed	74%	75%	80%	85%	86%
Percent Oil	60%	55%	60%	68%	72%
Reserve/Production Ratio (Years)	12.9	12.3	11.8	23.6	8.9
Future Net Operating Income-undiscounted [B]	$ 720,180	$ 408,272	$ 284,577	$ 704,146	$ 64,105
Discounted at 10% (before income tax) [B]	$ 378,300	$ 217,591	$ 150,616	$ 381,991	$ 40,405
Price Used to Calculate Year-End Reserves [B]					
Oil ($/Bbls)	$ 79.43	$ 61.18	$ 41.47	$ 96.01	$ 61.60
Natural Gas ($/Mcf)	$ 4.37	$ 3.83	$ 5.29	$ 7.47	$ 5.48
Production (Net Sales Volume)					
Oil (MBbls)	1,060	851	743	392	184
Natural Gas (MMcf)	4,789	4,944	2,962	1,648	577
Barrels of Oil Equivalent (MBoe)	1,858	1,675	1,236	667	280
Percent Oil	57%	51%	60%	59%	66%
Average Realized Prices for the Year					
Oil ($/Bbls)	$ 70.33	$ 61.09	$ 82.42	$ 67.20	$ 54.61
Natural Gas ($/Mcf)	$ 5.30	$ 3.97	$ 8.12	$ 6.19	$ 6.83
Financial Highlights					
Total Revenues	$ 107,017	$ 80,998	$ 94,606	$ 40,115	$ 16,805
Adjusted EBITDAX [C]	$ 69,119	$ 48,159	$ 54,150	$ 18,365	$ 8,721
Net Income Before Tax [D]	$ 35,254	$ 14,842	$ 21,291	$ 7,949	$ 4,280
Net Income [E]	$ 23,331	$ 9,775	$ 13,522	$ 3,069	$ 4,247
Total Assets	$ 359,690	$ 304,297	$ 243,534	$ 240,358	$ 50,667
Long-Term Debt	$ 87,000	$ 69,000	$ 40,000	$ 96,000	$ 5,000
Equity	$ 201,735	$ 174,677	$ 140,995	$ 68,032	$ 23,660
Weighted Average Common Shares Outstanding-Diluted	20,142	16,559	15,751	12,405	4,858

(A) In April 2007, GeoResources, Inc. entered into a reverse merger with Southern Bay Oil & Gas L.P. and acquired a subsidiary of Chandler Energy, LLC and certain oil and gas assets. The Company was the legal acquirer, but for financial reporting purposes, the transaction was accounted for as a reverse merger and therefore 2006 represents the activities of Southern Bay.

(B) SEC prescribed price, prior to adjustments for transportation, quality, etc.

(C) Adjusted EBITDAX is income before income taxes, interest expense, depletion and depreciation, impairments, exploration expense, hedging gains and losses and non-cash compensation. Adjusted EBITDAX should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not in accordance with, nor superior to, generally accepted accounting principles but provides additional information for evaluation of our operating performance. Please see page 30 for a reconciliation of Net Income to Adjusted EBITDAX.

(D) 2006 does not include any income tax expense as Southern Bay was a non-taxable entity.

(E) Includes a one-time tax accrual of $2.1 million in 2007 to reflect deferred taxes pursuant to generally accepted accounting principles.

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

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year ended December 31, 2010

Commission File Number – 0-8041

GeoResources, Inc.
(Exact name of registrant as specified in its charter)

Colorado	**84-0505444**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
110 Cypress Station Drive, Suite 220 Houston, Texas	**77090-1629**
(Address of principal executive offices)	**(Zip code)**

(281) 537-9920
(Registrant's telephone number, including area code)

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

Title of each class	Name of exchange on which registered
Common Stock, Par Value $0.01 Per Share	NASDAQ Global Select Market

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

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicated by check mark whether the registrant is a large accelerated file, an accelerated file, a non-accelerated filer, or a smaller reporting company. (Check one):

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2010: $180,766,713

Number of shares of the registrant's common stock outstanding at March 10, 2011: 25,420,842

DOCUMENTS INCORPORATED BY REFERENCE

Part III of this report incorporates by reference certain portions of the definitive proxy materials of the registrant in respect of its 2011 Annual Meeting of Shareholders.

TABLE OF CONTENTS

Forward-Looking Statements

Certain statements contained in this report on Form 10-K are not statements of historical fact and constitute forward-looking statements within the meaning of the various provisions of the Securities Act of 1933, as amended, (the "Securities Act") and the Securities Exchange Act of 1934, as amended (the "Exchange Act"), including, without limitation, the statements specifically identified as forward-looking statements within this report. Many of these statements contain risk factors as well. In addition, certain statements in our future filings with the SEC, in press releases, and in oral and written statements made by or with our approval which are not statements of historical fact constitute forward-looking statements within the meaning of the Securities Act and the Exchange Act. Examples of forward-looking statements, include, but are not limited to: (i) projections of capital expenditures, revenues, income or loss, earnings or loss per share, capital structure, and other financial items, (ii) statements of our plans and objectives or our management or board of directors including those relating to planned development of our oil and gas properties, (iii) statements of future economic performance and (iv) statements of assumptions underlying such statements. Words such as "believes," "anticipates," "expects," "intends," "targeted," "may," "will" and similar expressions are intended to identify forward-looking statements but are not the exclusive means of identifying such statements. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to:

- changes in production volumes, worldwide demand and commodity prices for oil and natural gas;
- changes in estimates of proved reserves;
- declines in the values of our oil and natural gas properties resulting in impairments;
- the timing and extent of our success in discovering, acquiring, developing and producing oil and natural gas reserves;
- our ability to acquire leases, drilling rigs, supplies and services on a timely basis and at reasonable prices;
- reductions in the borrowing base under our credit facility;
- risks incident to the drilling and operation of oil and natural gas wells;
- future production and development costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on prices;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America;
- changes in environmental laws and the regulation and enforcement related to those laws;
- the identification of and severity of environmental events and governmental responses to the events;
- legislative or regulatory changes, including retroactive royalty or production tax regimes, hydraulic-fracturing regulation, derivatives reform, and changes in state, federal and foreign income taxes;
- the effect of oil and natural gas derivatives activities; and
- conditions in the capital markets.

Such forward-looking statements speak only as of the date on which such statements are made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made to reflect the occurrence of unanticipated events.

CERTAIN DEFINITIONS

Unless the context otherwise requires, the terms "we," "us," "our" or "ours" when used in this report refer to GeoResources, Inc., together with its consolidated operating subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain terms used in this report:

After payout – With respect to an oil or natural gas interest in a property, refers to the time period after which the costs to drill and equip a well have been recovered.

AMI – Area of Mutual Interest

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

Bbls/d or ***BOPD*** – barrels per day.

Bcf – Billion cubic feet.

Bcfe – Billion cubic feet equivalent, determined using the ratio of six thousand cubic feet (Mcf) of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Before payout – With respect to an oil and natural gas interest in a property, refers to the time period before which the costs to drill and equip a well have been recovered.

Behind-pipe reserves – Those reserves expected to be recovered from completion interval(s) not yet open but still behind casing in existing wells.

BOE – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

Carried interest – A contractual arrangement, usually in a drilling project, whereby all or a portion of the working interest cost participation of the project originator is paid for by another party in exchange for earning an interest in such project.

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.

Compression – A force that tends to shorten or squeeze, decreasing volume or increasing pressure.

DD&A – Depreciation, depletion and amortization.

Developed acreage – The number of acres which are allotted or assignable to producing wells or wells capable of production.

Development activities – Activities following exploration including the installation of facilities and the drilling and completion of wells for production purposes.

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

Dry hole or well – A well found to be incapable of producing hydrocarbons economically.

Exploitation – The act of making oil and gas property more profitable, productive or useful.

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

Farm-in or ***Farm-out*** – An agreement whereunder the owner of a working interest in an oil and natural gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty and/or reversionary interest in the lease. The interest received by the assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

FASB – The Financial Accounting Standards Board.

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

GAAP – Generally accepted accounting principles in the United States of America.

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

Horizontal drilling – A drilling technique that permits the operator to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques that may, depending on horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Injection well – A well used to inject gas, water, or liquefied petroleum gas under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

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

MBOE – one thousand barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

Mbtu (Mmbtu) – Used as a standard unit of measurement for natural gas and provides a convenient basis for comparing the energy content of various grades of natural gas and other fuels. One cubic foot of natural gas produces approximately 1,000 BTUs, so 1,000 cubic feet of gas is comparable to 1 MBTU. MBTU is often expressed as MMBTU, which is intended to represent a thousand BTUs.

Mcf – One thousand cubic feet.

Mcf/d – One thousand cubic feet per day.

Mcfe – One thousand cubic feet equivalent determined by using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids, which approximates the relative energy content of crude oil, condensate and natural gas liquids as compared to natural gas. Prices have historically been higher or substantially higher for crude oil than natural gas on an energy equivalent basis although there have been periods in which they have been lower or substantially lower.

MMcf – One million cubic feet.

MMcf/d – One million cubic feet per day.

MMcfe – One million cubic feet equivalent.

Net acres or ***net wells*** – The sum of the fractional working interests owned in gross acres or gross wells.

NGL's – Natural gas liquids measured in barrels.

NRI or ***Net Revenue Interests*** – The share of production after satisfaction of all royalty, oil payments and other non-operating interests.

Normally pressured reservoirs – Reservoirs with a formation-fluid pressure equivalent to 0.465 PSI per foot of depth from the surface. For example, if the formation pressure is 4,650 PSI at a depth of 10,000 feet, the pressure is considered to be normal.

Over-pressured reservoirs – Reservoirs with a formation fluid pressure greater than 0.465 PSI per foot of depth from the surface.

Plant products – Liquids generated by a plant facility; including propane, iso-butane, normal butane, pentane and ethane.

Plugging and abandonment or ***P&A*** – 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.

PV10% – The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices, as prescribed in the SEC rules, and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, depreciation, depletion and amortization, or Federal income taxes and discounted using and annual discount rate of 10%. PV10% is considered a non-GAAP financial measure as defined by the SEC.

Primary recovery – The first stage of hydrocarbon production in which natural reservoir drives are used to recover hydrocarbons, although some form of artificial lift may be required to exploit declining reservoir drives.

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

Proved developed nonproducing reserves or ***PDNP*** – Proved developed nonproducing reserves are proved reserves that are either shut-in or are behind-pipe reserves.

Proved developed producing reserves or ***PDP*** – Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market.

Proved developed reserves – Proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods.

Proved reserves – The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped location – A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves or ***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.

Recompletion – The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

Re-engineering – a process involving a comprehensive review of the mechanical conditions associated with wells and equipment in producing fields. Our re-engineering practices typically result in a capital expenditure plan, which is implemented over time, to workover (see below) and re-complete wells and modify down-hole artificial lift equipment and surface equipment and facilities. The programs are designed specifically for individual fields to increase and maintain production, reduce down-time and mechanical failures, lower per-unit operating expenses, and therefore, improve field economics.

Reprocessing – Taking older seismic data and performing new mathematical techniques to refine subsurface images or to provide additional ways of interpreting the subsurface environment.

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.

Royalty interest – An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SEC – The U.S. Securities and Exchange Commission.

Secondary recovery – The use of water-flooding or gas injection to maintain formation pressure during primary production and to reduce the rate of decline of the original reservoir drive.

Shut-in reserves – Those reserves expected to be recovered from completion intervals that were open at the time the reserve was estimated but were not producing due to market conditions, mechanical difficulties or because production equipment or pipelines were not yet installed.

Standardized Measure of Discounted Future Net Cash Flows – Present value of proved reserves, as adjusted to give effect to estimated future abandonment costs, net of estimated salvage value of related equipment, and estimated future income taxes.

3-D seismic – An advanced technology method of detecting accumulation of hydrocarbons identified through a three-dimensional picture of the subsurface created by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

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.

Waterflooding – The secondary recovery method in which water is forced down injection wells laid out in various patterns around the producing wells. The water injected displaces the oil and forces it to the producing wells.

Working interest or **WI** – The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and share of production, subject to all royalties, overriding royalties and other burdens and to share in all costs of exploration, development operations and all risks in connection therewith.

Workover – Operations on a producing well to restore or increase production.

PART I

Item 1. Business

Overview

GeoResources, Inc. (the "Company," "we" or "us"), a Colorado corporation, is an independent oil and gas company engaged in the acquisition and development of oil and gas reserves through an active and diversified program which includes purchases of reserves, re-engineering, development and exploration activities primarily focused in the Southwest, Gulf Coast and the Williston Basin areas of the United States. Our corporate headquarters and Southern Division operating offices are located in Houston, Texas, and our Northern Division operating office is located in Denver, Colorado. We also have an additional operating office for the Northern Division in Williston, North Dakota.

Our strategy, which is further discussed below, calls for operations in multiple basins and also includes a combination of acquisition, development and exploration activities. Management believes, this approach allows us to manage risk and also take advantage of changing market conditions and regional differences in commodity pricing and costs and available infra-structure. At present our exploration and development activities are principally focused on the development of our acreage positions in the Bakken shale trend in the Williston basin and the Eagle Ford shale trend in Texas. In these two areas, at present we hold 44,000 net acres and 21,000 net acres, respectively.

As of January 1, 2011, we had an estimated 23,985 MBOE of proved reserves being approximately 60% oil and 74% developed. Production for the year ended December 31, 2010 totaled 1,858 MBOE or 5,090 BOE per day of which 57% was oil. In addition, we have a general partner and operating interest in two managed limited partnerships, which are accounted for on the equity method. Our share of partnership reserves, at January 1, 2011 were estimated at 1,361 MBOE, being 96% natural gas and 89% developed. See Item 2 of this report for additional information related to our oil and gas reserves at January 1, 2011.

Recent Developments

Acquisition and Divestitures

During 2010 we continued our drilling programs and expanded our acreage positions. We also acquired producing and undeveloped properties, principally in the Bakken Shale trend in the Williston Basin, North Dakota and in the Giddings field, Texas. A summary of our 2010 activities is as follows:

- In October 2009, the Company initiated a leasing program in Williams County, North Dakota with the objective of establishing a significant operated position in the Bakken shale trend. In February 2010, the Company entered into agreements with two unaffiliated third parties under which we sold each of them an interest in existing acreage, and they agreed to acquire with us additional acreage and jointly develop the project area. Cash proceeds to us totaled approximately $20 million and we retained a 47.5% working interest in the project area. The agreement also provided for up to $10 million ($4.75 million net to the Company) of additional joint leasing in a contractually specified area of mutual interest ("AMI"). As of December 31, 2010 our net acreage position in the project area totaled approximately 24,000 acres. For accounting purposes the Company uses the cost recovery method; under this method proceeds from joint owners have been recorded in the balance sheet as a reduction to the carrying value of the unproved properties.
- On July 30, 2010 the Company closed an acquisition of producing oil and gas properties located in the Giddings field of Central Texas. The purchase price was $16.6 million plus closing adjustments for normal operations activity. The acquisition covered approximately 9,700 net acres and was funded through borrowings under our credit facility.
- In September 2010, we entered into an agreement with an unaffiliated third party to jointly acquire and develop mineral leases in the Eagle Ford shale trend of Texas. As part of this agreement, the Company sold a 50% working interest in its acreage for $20 million. For accounting purposes, the Company uses the cost recovery method; under this method, proceeds from joint owners are recorded in the balance sheet as a reduction of the carrying value of unproved properties. The purchaser also agreed to pay the drilling costs for the first six wells to be drilled in a contractually specified AMI. The agreement also provides for an additional $20 million ($10 million net) for additional leasing within the AMI. Subsequent to the initial closing, the Company and the joint owners have continued to acquire leases within the AMI pursuant to the terms of the agreement.
- In November 2010, the Company purchased an 86.67% membership interest in Trigon Energy Partners, LLC ("Trigon"), which owns undeveloped leases in the Eagle Ford shale trend of Texas for approximately $11.8 million. The Company fully consolidated Trigon and recorded a non-controlling minority interest of $2.2 million at December 31, 2010. For the year ended December 31, 2010, Trigon did not generate any revenue or net income. The Company's share of Trigon's undeveloped leases is included in Eagle Ford acreage totals throughout this report.

Long-term Debt

On July 13, 2009, we entered into a Second Amended and Restated Credit Agreement ("Second Amended Credit Agreement"), which increased our previous credit facility from $200 million to $250 million and extended the term of the agreement to October 16, 2012. The initial borrowing base of the facility was $135 million, subject to redetermination on May 1 and November 1 of each year. On November 9, 2009 the borrowing base was increased to $145 million. The Second Amended Credit Agreement provides for interest rates at (a) LIBOR plus 2.25% to 3.00% or (b) the prime lending rate plus 1.25% to 2.00%, depending upon the amount borrowed and also requires the payment of commitment fees to the lender in respect of the unutilized commitments. The commitment rate is 0.50% per annum. We incurred costs of approximately $2.5 million to complete the amendment and we are amortizing these costs over the remaining life of the Second Amended Credit Agreement; the amortization is included in interest expense. The participating banks include: Wells Fargo Bank; Comerica Bank; BBVA Compass; U.S. Bank; Frost National Bank; Bank of Texas and Natixis. In January 2011, we paid all of our outstanding debt.

Stock Issuances

On June 5, 2008, we issued 1,533,334 shares of our common stock and 613,336 warrants to purchase common stock to non-affiliated accredited investors pursuant to exemptions from registration under federal and state securities laws. The shares of common stock were sold for $22.50 per shares. The warrants have a term of five years ending June 5, 2013, with an exercise price $32.43 per share. The net proceeds of the offering were $32.2 million.

On December 1, 2009, we issued 3,450,000 shares of our common stock at $10.20 per share to investors pursuant to an offering registered with the SEC. The closing included the exercise in full of the underwriters' over-allotment option. Net proceeds from the offering were approximately $33.1 million after deducting the underwriters' discount and other offering expenses, and were used to reduce outstanding indebtedness under our Second Amended Credit Agreement.

On January 19, 2011, we issued 5,175,000 shares of common stock and 989,000 shares were sold by certain selling shareholders, at a price to the public of $25.00 per share. Net proceeds to the Company from the offering were approximately $122.9 million after deducting the underwriters' discount and other offering expenses, and were used to reduce our outstanding indebtedness under our Second Amended Credit Agreement of $87 million. We anticipate that the remaining net proceeds will primarily be used to fund drilling and development expenditures.

Our Business Strategy

Our strategy includes a combination of acquisitions, development and exploration activities, currently focused primarily on oil projects in the Bakken trend in the Williston Basin of North Dakota and Montana and in the Eagle Ford trend in Texas. We focus on building production, reserves and cash flows and continually work to expand our undeveloped acreage and drilling inventory as well as our high-grade assets. Historically, we have shifted our emphasis among these basic activities to take advantage of changing market conditions to facilitate profitable growth.

Our business strategy includes:

- Acquiring oil and gas reserves, in our focus areas, through asset or corporate acquisitions or mergers;
- Expanding acreage positions and drilling inventory with an emphasis on operated positions and selective participations with other capable oil and gas operators; and
- Development, exploitation and exploration programs intended to increase production and proved reserves.

Our fundamental operating and technical strategy is complemented by management's commitment to increasing shareholder value by:

- Maintaining a sound capital structure;
- Promoting industry and institutional partners into projects to manage risk, enhance rates of return and lowering net finding and development costs;
- Controlling capital, operating and administrative costs;
- Hedging a portion of production to provide a foundation of predictable cash flows to support development and exploration activities; and
- Divesting non-core assets to high-grade our property portfolio.

In the opinion of management, our strategy is appropriate for us because:

- It addresses multiple risks of oil and gas operations while providing shareholders with significant upside potential; and
- It results in "staying-power", which management believes is essential to mitigate the adverse impacts of volatile commodity prices and financial markets and it is the strategy employed successfully in prior entities formed, acquired and operated by management.

Each component of our business strategy and related matters are briefly discussed below.

Acquisitions and Divestitures – The fundamental intent of our acquisition and divestiture activities is to continually high-grade our property portfolio. Such acquisitions of oil and gas producing or undeveloped properties, either through corporate or asset acquisitions, is intended to allow us to assemble a portfolio of properties with the potential for meaningful economic returns from (1) the application of operational and technical attention, (2) development of non-producing reserves, and (3) realization of exploration upside. We seek to acquire oil and gas interests with the characteristics of manageable risks, fairly predictable production and value enhancement potential. An important part of our post-acquisition activities associated with producing properties are re-engineering projects intended to implement more efficient production practices, increase production or arrest production declines, lower per-unit operating expenses and/or reduce field down-time. Our producing properties include certain non-core legacy properties that are providing production and cash flows to pursue other opportunities. Consistent with our growth and in order to devote our human resources toward our most significant projects, periodically we will divest non-core assets.

Development Activities – The largest part of our capital expenditures relates to the development and exploitation of non-producing reserves and development/expansion of our core acreage positions. In our core areas, we conduct comprehensive regional geological and geophysical studies and detailed field studies of existing properties which usually result in identifying:

- Specific areas of interest for us to pursue additional leasing, farm-out or other activities, intended to expand our acreage positions; and
- Additional development and exploration projects associated with existing properties to recover bypassed, undeveloped or under-developed reserves.

Exploration – Our exploration activities are intended to provide significant upside potential; accordingly, we expect to continue to expand our exploration activities as our asset base increases. This strategy is designed to:

- Expand our inventory of substantive acreage and prospects;
- Fully develop acquired properties; and
- Realize substantial economic returns from exploration.

Corporate Mergers and Acquisitions – As a distinct part of our overall strategy, we continue to pursue corporate merger and acquisition opportunities as a means to increase shareholder value. Criteria for such acquisitions might include, but are not limited to:

- The potential to increase assets in a core area;
- The opportunity to increase our earnings and cash flow on a per share basis;
- Development and exploration potential; and
- Realization of administrative savings.

In summary, we believe our business practices and methodical processes will maintain our reserve and production base and lead to growth in reserves, production, cash flow and consequently, in per share values.

Marketing of Production

Our oil and gas production is marketed to third parties consistent with industry practices. Typically, oil is sold at the wellhead at field posted prices or market indices, plus or minus adjustments for quality or transportation. Natural gas is usually sold under a contract at a negotiated price based upon the "spot" market for gas sold in the area.

Our oil and gas sales contracts and off-lease marketing arrangements are generally standard industry contracts with 30 to 90 day cancelation notice provisions. We do not have any contracts to supply crude oil or natural gas which exceed one year. We have not spent any material time or funds on research and development and do not expect to do so in the foreseeable future. In addition, as discussed elsewhere in this report, we have entered into long-term commodity hedge contracts to mitigate the effects of price declines of oil and natural gas.

Competition

In addition to being highly speculative, the domestic oil and gas business is highly competitive among many independent operators and major oil companies in the industry. Many competitors possess financial resources and technical facilities greater than those available to us and they may, therefore, be able to pay more for desirable properties or more effectively exploit productive prospects due to their size and ability to secure better service contracts.

Environmental Regulations

We conduct our operations according to high industry standards and in full compliance with all applicable regulations. Our operations are generally subject to numerous stringent federal, state and local environmental regulations under various acts including the Comprehensive Environmental Response, Compensation and Liability Act, the Federal Water Pollution Control Act, and the Resources Conservation and Recovery Act. For example, our operations are affected by diverse environmental regulations including those regarding the disposal of produced oilfield brines, other oil-related wastes, and additional wastes not directly related to oil and gas production. Additional regulations exist regarding the containment and handling of crude oil as well as preventing the release of oil into the environment. It is not possible to estimate future environmental compliance costs due in part, to the uncertainty of continually changing environmental initiatives. While future environmental costs can be expected to be significant to the entire oil and gas industry, we do not believe that our costs would be any more of a relative financial burden than others in our industry.

Foreign Operations and Export Sales

We do not have any interests, production facilities, or operations in foreign countries.

Employees

As of December 31, 2010, we had 60 full-time employees, 42 of which are management, technical and administrative personnel, and 18 are field employees. Contract personnel operate some of our producing fields under the direct supervision of our employees. We consider all relations with our employees to be good. We have no unions and are not the subject of any collective bargaining agreements.

Available Information

We maintain a website at the address www.georesourcesinc.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. Through our website, we make available our Annual Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and amendments to these reports, as soon as reasonably practicable after we file such material with the SEC.

Item 1A. Risk Factors

Set forth below are risks with respect to our Company. Readers should review these risks, together with the other information contained in this report. The risks and uncertainties we have described in this report are not the only ones we face. Additional risks and uncertainties that are not presently known to us, or that we presently deem immaterial, may become material and also adversely affect our business. Any of the risks discussed in this report that are presently unknown or immaterial, if they were to actually occur, could result in a significant adverse impact on our business, operating results, prospects and/or financial condition. See "Forward Looking Statements" at the beginning of this report for additional risks.

We are dependent upon the services of our chief executive officer and other executive officers.

We are dependent upon a limited number of personnel, including Frank A. Lodzinski, our Chief Executive Officer and President, and other management personnel and key employees. Failure to retain the services of these persons, or to replace them with adequate personnel in the event of their departure or termination, may have a material adverse effect on our operations. No employment agreements with any of our officers currently exist, but we may consider such agreements in the future. We have no key-man life insurance on the lives of any of our executive officers.

We must successfully acquire or develop additional reserves of oil and gas.

Our future production of oil and gas is highly dependent upon our level of success in acquiring or finding additional reserves. The rate of production from our oil and gas properties generally decreases as reserves are produced. We may not be able to acquire or develop oil and gas properties economically due to a lack of drilling success as well as lack of capital and inability to obtain adequate financing, which may be required to fund prospect generation, drilling operations and property acquisitions.

Intense competition in the oil and gas exploration and production segment could adversely affect our ability to acquire desirable properties prospective for oil and gas, as well as producing oil and gas properties.

The oil and gas industry is highly competitive. We compete with major integrated and independent oil and gas companies for the acquisition of desirable oil and gas properties and leases, for the equipment and services required to develop and operate properties, and in the marketing of oil and gas to end-users. Many competitors have financial and other resources that are substantially greater than ours, which could, in the future, make acquisitions of producing properties at economic prices difficult for us. In addition, many larger competitors may be better able to respond to factors that affect the demand for oil and natural gas production, such as changes in worldwide oil and natural gas prices and levels of production, the cost and availability of alternative fuels and the application of government regulations. We also face significant competition in attracting and retaining experienced, capable and technical personnel, including geologists, geophysicists, engineers, landmen and others with experience in the oil and gas industry.

The domestic oil and gas exploration and production industry is faced with shortages of personnel and equipment, and such shortages may adversely affect our operations and financial results.

The oil and gas industry, as a whole, suffers from an aging workforce and a shortage of qualified and experienced personnel. Our operations and financial results may be adversely impacted due to difficulties in attracting and retaining such personnel within our Company or within companies that provide materials and services to the industry. Additional personnel are likely to be required in connection with our expansion plans, and the domestic oil and gas industry has in the past experienced significant shortages of qualified personnel in all areas of operations. Further, our expansion plans will likely require access to services and oil field equipment. Such equipment and operating personnel are currently in short supply. The substantial increase in commodity prices in 2010 has resulted in increased drilling and construction activity in the industry and shortages of personnel and equipment are present in our primary areas of focus – the Williston Basin in North Dakota and the Eagle Ford trend in Texas.

The unavailability of drilling rigs and field services in the Bakken trend in North Dakota and the Eagle Ford trend in Texas could adversely affect our ability to execute our development plans within our budget on a timely basis.

Existing shortages of drilling rig service providers for pressure pumping and other services required for well completion in the Bakken trend in North Dakota and Montana and the Eagle Ford trend in Texas have delayed our development and production operations and caused us to incur additional expenditures that were not provided for in our capital budget. We cannot determine the magnitude or length of these shortages, but they could have a material adverse effect on our business cash flows, financial condition or results of operations.

We may experience significant delays between drilling and completion on both our operated and non-operated properties in the Bakken trend and the Eagle Ford trend.

Industry-wide delays between drilling and completion operations in Bakken trend and the Eagle Ford trend may continue to increase. Increased delays could delay or adversely affect our exploration, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our financial condition and results of operations.

Our success will depend on the results of our exploitation, exploration, development and production activities. Oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Furthermore, many factors may curtail, delay or cancel drilling, including:

- Shortages of or delays in obtaining equipment and qualified personnel such as we are currently experiencing;
- Pressure or irregularities in geological formations;
- Equipment failures or accidents;
- Adverse weather conditions;
- Reductions in oil and natural gas prices;
- Issues associated with property titles; and
- Delays imposed by or resulting from compliance with regulatory requirements.

Volatile oil and natural gas prices could adversely affect our financial condition and results of operations.

Our most significant market risk is the pricing of crude oil and natural gas. Management expects energy prices to remain volatile and unpredictable. Moreover, oil and natural gas prices depend on factors that are outside of our control, including:

- Economic and energy infrastructure disruptions caused by actual or threatened acts of war, or terrorist activities particularly with respect to oil producers in the Middle East, Nigeria and Venezuela;
- Weather conditions, such as hurricanes, including energy infrastructure disruptions resulting from those conditions;
- Changes in the global oil supply, demand and inventories;
- Changes in domestic natural gas supply, demand and inventories;
- The price and quantity of foreign imports of oil;
- The price and availability of liquefied natural gas imports;
- Political conditions in or affecting other oil-producing countries;
- General economic conditions in the United Stated and worldwide;
- The level of worldwide oil and natural gas exploration and production activity;
- Technological advances affecting energy consumption; and
- The price and availability of alternative fuels.

Lower oil and natural gas prices not only decrease revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can economically produce. Lower prices also negatively impact estimates of our proved reserves. We have attempted to mitigate the risks associated with commodity price fluctuations by hedging a portion of production through price swaps and costless collars. However, substantial or extended declines in oil or natural gas prices may still materially and adversely affect our financial condition, results of operations, liquidity or ability to finance operations and planned capital expenditures.

Industry changes may adversely affect various financial measurements and negatively affect the market price of our common stock.

Although we believe that our business strategy has and will allow us to continue our growth and increase operating efficiencies, unforeseen costs and industry changes, as listed below, could potentially have an adverse effect on return of capital and earnings per share. Future events and conditions could cause any such changes to be significant, including, among other things, adverse changes in:

- Commodity prices for oil, natural gas and liquid natural gas;
- Reserve levels;
- Operating results;
- Capital expenditure obligations; and
- Production levels.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

Oil and natural gas exploration, drilling and production activities are subject to numerous operating risks including the possibility of:

- Blowouts, fires and explosions;
- Personal injuries and death;
- Uninsured or underinsured losses;
- Unanticipated, abnormally pressured formations;
- Mechanical difficulties, such as stuck oil field drilling and service tools and casing collapses; and
- Environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination.

Any of these operating hazards could cause damage to properties, serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs, and other environmental damages, which could expose us to liabilities.

We have hurricane associated risks in connection with our operations in the Texas and Louisiana Gulf Coast.

We have experienced in the past significant production curtailments due to hurricane damage. We could also be subject to production curtailments in the future resulting from hurricane damage to certain fields or, even in the event that producing fields are not damaged, production could be curtailed due to damage to facilities and equipment owned by oil and gas purchasers, or vendors and suppliers, because a portion of our oil and gas properties are located in or near coastal areas of the Texas and Louisiana Gulf Coast.

Insurance may not fully recover potential losses.

Although we believe that we are reasonably insured against losses to wells and associated equipment, potential operational or hurricane related losses could result in a loss of our reserves and properties and materially reduce the funds available for exploration and development activities and acquisitions. The insurance market, in general, and the energy insurance market in particular, have experienced substantial cost increases over recent years, resulting from significant losses associated with hurricanes and commercial losses. To offset the significant cost increases we have increased our deductibles and made other modifications to coverage. We believe these changes are reasonable, considering both the underlying risks and our size and financial standing. The potential for loss, however, cannot be accurately or reasonably predicted. If we incur substantial damages or liabilities that are not fully covered by insurance or are in excess of policy limits, then our business, results of operations, and financial condition could be materially affected. Also, as is customary in the oil and gas business, we do not carry business interruption insurance. In the future, it is also possible that we will further modify insurance coverage or determine not to purchase some insurance because of high insurance premiums.

If oil and gas prices decrease or exploration efforts are unsuccessful, we may be required to write-down the capitalized cost of individual oil and gas properties.

A writedown of the capitalized cost of individual oil and gas properties could occur when oil and gas prices are low or if we have substantial downward adjustments to our estimated proved oil and gas reserves, if operating costs or development costs increase over prior estimates, or if exploratory drilling is unsuccessful. A writedown could adversely affect the trading prices of our common stock.

We use the successful efforts accounting method. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves are discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. All geological and geophysical costs on exploratory prospects are expensed as incurred.

The capitalized costs of our oil and gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, pursuant to generally accepted accounting principles, we are required to record impairment charges to reduce the capitalized costs of each such field to its estimate of the field's fair market value, even though other fields may have increased in value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce earnings and shareholders' equity.

Revisions of oil and gas reserve estimates could adversely affect the trading price of our common stock. Oil and gas reserves and the standardized measure of cash flows represent estimates, which may vary materially over time due to many factors.

The market price of our common stock may be subject to significant decreases due to decreases in our estimated reserves, our estimated cash flows and other factors. Estimated reserves may be subject to downward revision based upon future production, results of future development, prevailing oil and gas prices, prevailing operating and development costs and other factors. There are numerous uncertainties and uncontrollable factors inherent in estimating quantities of oil and gas reserves, projecting future rates of production, and timing of development expenditures.

In addition, the estimates of future net cash flows from proved reserves and the present value of proved reserves are based upon various assumptions about prices and costs and future production levels that may prove to be incorrect over time. Any significant variance from the assumptions could result in material differences in the actual quantity of reserves and amount of estimated future net cash flows from estimated oil and gas reserves.

Our hedging activities may prevent us from realizing the benefits in oil or gas price increases.

In an attempt to reduce our sensitivity to oil and gas price volatility, we have, and will likely continue to, enter into hedging transactions which may include fixed price swaps, price collars, puts and other derivatives. In a typical hedge transaction, we may fix the price, a floor or a range, on a portion of our production over a predetermined period of time. It is expected that we will receive, from the counter-party to the hedge, payment of the excess of the fixed price specified in the hedge contract over a floating price based on a market index, multiplied by the volume of the production hedged. Conversely, if the floating price exceeds the fixed price, we would be required to pay the counter-party such price difference multiplied by the volume of production hedged. There are numerous risks associated with hedging activities such as the risk that reserves are not produced at rates equivalent to the hedged position, and the risk that production and transportation cost assumptions used in determining an acceptable hedge could be substantially different from the actual cost. In addition, the counter-party to the hedge may become unable or unwilling to perform its obligations under hedging contracts, and we could incur a material adverse financial effect if there is any significant non-performance. While intended to reduce the effects of oil and gas price volatility, hedging transactions may limit potential gains earned by us from oil and gas price increases and may expose us to the risk of financial loss in certain circumstances.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative contracts to reduce the effect of commodity price, interest rate and other risks associated with our business.

The recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") is comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission ("CFTC") and the SEC to promulgate rules and regulations implementing certain portions of it by mid-July 2011. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt similar rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may require us to comply with margin requirements and with certain clearing and trade-execution requirements, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative contracts to spin off some of their derivatives contracts to a separate entity, which may not be as creditworthy as the current counterparty. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral), 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 our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower the commodity prices we realize. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

The use of debt financing may adversely affect our business strategy.

We have used debt to fund a portion of our activities and we will likely use debt to fund a portion of our future acquisition activities. Any temporary or sustained inability to service or repay debt will materially adversely affect our results of operations and financial condition and will materially adversely affect our ability to obtain other financing.

We are obligated to comply with financial and other covenants in our existing Second Amended Credit Facility that could restrict our operating activities, and the failure to comply could result in defaults that accelerate the payment of our debt.

Our Second Amended Credit Facility generally contains customary covenants, including, among others, provisions:

- Relating to the maintenance of the oil and gas properties securing the debt;
- Restricting our ability to assign or further encumber the properties securing the debt; and
- All of our obligations under the Second Amended Credit Facility are secured by substantially all of our assets.

In addition, our Second Amended Credit Facility requires us to maintain financial covenants, including, but not limited to the following:

- A current ratio of not less than 1.0:1.0 excluding current hedge obligations;
- A funded debt to EBITDAX ratio of not greater than 4.0:1.0; and
- An interest coverage ratio, which is the ratio of the EBITDAX for the four most recently completed quarters ending on such date compared to the cash interest payments made for such fiscal quarters, of not less than 3.0:1.0.

As of the date of this report, we were in compliance with all such covenants. If we were to breach any of our debt covenants and not cure the breach within any applicable cure period, the lender could require us to immediately repay any outstanding debt amounts at the time, and if the debt is secured, could immediately begin proceedings to take possession of substantially all of our properties. Any such property losses would materially and adversely affect our cash flow and results of operations.

Global financial and economic circumstances may have impacts on our business and financial condition that we currently cannot predict.

Global financial markets may have an adverse impact on our business and our financial condition, and we may face challenges if conditions in the financial markets are inadequate to finance our activities at a reasonable cost of capital. While the current economic situation has improved since 2008 any deterioration in financial markets (or changes in lending practices) could have a material adverse impact on our lenders. Furthermore, adverse economic circumstances could cause customers, joint owners or other parties with whom we transact business to fail to meet their obligations to us. Additionally, market conditions could have a materially adverse impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection. Also, worldwide economic conditions could lead to reduced demand for oil and natural gas, or lower prices for oil and natural gas, or both, which could have a material negative impact on our revenues, results of operations and financial conditions.

Our properties may be subject to influence by third parties that do not allow us to proceed with planned explorations and expenditures.

We are the operator of a majority of our properties, but for many of our properties we own less than 100% of the working interests. Joint ownership is customary in the oil and gas industry and is generally conducted under the terms of a joint operating agreement ("JOA"), where a single working interest owner is designated as the "operator" of the property. For properties where we own less than 100% of the working interest, whether operated or non-operated, drilling and operating decisions may not be within our sole control. If we disagree with the decision of a majority of working interest owners, we may be required, among other things, to postpone the proposed activity or decline to participate. If we decline to participate, we might be forced to relinquish our interest through "in-or-out" elections or may be subject to certain non-consent penalties, as provided in a JOA. In-or-out elections may require a joint owner to participate, or forever relinquish its position. Non-consent penalties typically allow participating working interest owners to recover from the proceeds of production, if any, an amount equal to 200% to 500% of the non-participating working interest owner's share of the cost of such operations.

Recent legislative proposals could materially lessen the economic viability of domestic exploration and production companies, including us.

The budgetary proposals of the Obama Administration, if enacted into law by Congress, could have a material adverse impact on the domestic oil and gas industry and on exploration and production companies in particular. The proposals would eliminate the so called "oil and gas company preferences" and raise other taxes on the industry. The proposed budget would eliminate tax mechanisms critical to capital formation for drilling, such as expensing of intangible drilling costs and eliminating the percentage depletion allowance, and if enacted, would have a significant adverse impact on domestic drilling for oil and natural gas. The proposed budget would also charge producers user fees for processing permits to drill on federal lands and increase royalty rates of minerals produced from federal lands. We cannot predict the outcome of the proposed U.S. Government budget, but the enactment of any of the proposals would likely adversely affect the domestic oil and gas exploration and production business by making future production more difficult and expensive, thereby lessening the economic viability of these companies, of which we are part.

Recovery of investments in acquiring oil and gas properties is uncertain.

We cannot assure that we will recover the costs we incur in acquiring oil and gas properties. While the acquisition and development of oil and gas properties is based on engineering, geological and geophysical assessments, such data and analysis is inexact and inherently uncertain. There can be no assurance that any properties we acquire will be economically produced or developed. Re-engineering operations pose the risk that anticipated benefits, which may include reserve additions, production rate improvements or lower recurring operating expenses, may not be achieved, or that actual results obtained may not be sufficient to recover investments. Drilling activities, whether exploratory or developmental, are subject to mechanical and geological risks, including the risk that no commercially productive reservoirs will be encountered. Unsuccessful acquisitions, re-engineering or drilling activities could have a material adverse effect on our results of operations and financial condition.

We cannot assure we would be able to achieve continued growth in assets, production or revenue.

There can be no assurance that we will continue to experience growth in revenues, oil and gas reserves or production. Any future growth in oil and gas reserves, production and operations will place significant demands on us and our management and personnel. Our future performance and profitability will depend, in part, on our ability to successfully integrate acquired properties into our operations, develop such properties, hire additional personnel and implement necessary enhancements to our management systems.

The nature of our business and assets may expose us to significant compliance costs and liabilities.

Our operations involving the exploration, production, storage, treatment, and transportation of liquid hydrocarbons, including crude oil, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety, and related employee health and safety matters. Compliance with all of these laws and regulations may represent a significant cost of doing business. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory and remedial liabilities; and the issuance of injunctions that may restrict, inhibit or prohibit our operations; or claims of damages to property or persons.

Compliance with environmental laws and regulations may require us to spend significant resources.

Environmental laws and regulations may: (1) require the acquisition of a permit before well drilling commences; (2) restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; (3) prohibit or limit drilling activities on certain lands lying within wetlands or other protected areas; and (4) impose substantial liabilities for pollution resulting from past or present drilling and production operations. Moreover, changes in Federal and state environmental laws and regulations, as well as how such laws and regulations are administered, could occur and may result in more stringent and costly requirements which could have a significant impact on our operating costs. In general, under various applicable environmental regulations, we may be subject to enforcement action in the form of injunctions, cease and desist orders and administrative, civil and criminal penalties for violations of environmental laws. We may also be subject to liability from third parties for civil claims by affected neighbors arising out of a pollution event. Laws and regulations protecting the environment may, in certain circumstances, impose strict liability rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. Such laws and regulations may expose us to liability for the conduct of or conditions caused by others, or for our acts which were in compliance with all applicable laws at the time such acts were performed. We believe we are in compliance with applicable environmental and other governmental laws and regulations. In recent years, increased concerns have been raised over the protection of the environment. Legislation to regulate the emissions of greenhouse gases has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues, such as the United Nations Climate Change Conference in Copenhagen in 2009. Also, the EPA has undertaken new efforts to collect information regarding greenhouse gas emissions and their effects.

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

On December 15, 2009, the U.S. Environmental Protection Agency, or EPA, published its findings that emissions of carbon dioxide, methane, and other greenhouse gases, or "GHGs," present an endangerment to public health and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, effective as of when the motor vehicle standards took effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG that have yet to be developed. In addition, on November 8, 2010, the EPA adopted the final rule which expands its existing GHG reporting rule to include certain onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. The final rule is effective as of December 30, 2010 and requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. Our operations will likely be subject to the latter rule.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and more than one-third of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. The adoption of any legislation or regulations that limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations and could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have in an adverse effect on our assets and operations.

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

Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with several wells or proposed wells for which we are the operator. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs, especially shale formations such as the Bakken and the Eagle Ford, where we have significant acreage. The process is typically regulated by state oil and gas commissions. However, Congress recently has considered two companion bills in connection with the proposed "Fracturing Responsibility and Awareness of Chemicals Act" (the "FRAC Act"). While now not under consideration by Congress, if reintroduced, the bills would repeal an exemption in the Federal Safe Drinking Water Act ("SWDA") for the underground injection of hydraulic fracturing fluids near drinking water sources and require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of the FRAC Act have asserted that chemicals used in the fracturing process may be adversely impacting drinking water supplies. If reintroduced, the legislation would require the reporting and public disclosure of chemicals used in the fracturing process. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Further, if reintroduced and enacted, the FRAC Act could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. In addition, the Energy and Commerce Committee of the United States House of Representatives is conducting an investigation of hydraulic fracturing practices.

Recently, the U.S. Environmental Protection Agency ("EPA") asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SWDA's Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. On February 8, 2011, the EPA submitted its draft study plan on the effects of hydraulic fracturing on human health and the environment to the EPA's Science Advisory Board for comment. Thereafter, the EPA will revise and begin the study. The EPA expects to make public its initial findings by the end of 2012 and an additional report with further research in 2014. Further, the agency has announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector, and has already commenced one potential enforcement matter in Texas. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. If hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and also to attendant permitting delays and potential increases in costs.

In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. For example, Pennsylvania, Colorado, and Wyoming have each adopted a variety of well construction, set back, and disclosure regulations limiting how fracturing can be performed and requiring various degrees of chemical disclosure. These regulations affect our operations, increase our costs of exploration and production and limit the quantity of natural gas and oil that we can economically produce. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities on a timely basis following leasing. Delays in obtaining regulatory approvals, drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase our financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff.

Our failure to successfully identify, complete and integrate future acquisitions of properties or business could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and effectively manage additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our price risk management arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. Even if our credit reviews work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could adversely affect our business.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, natural gas and oil prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to economically produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue making substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed, and in the future we intend to continue to finance, capital expenditures primarily with cash generated by operations, proceeds from bank borrowings, including under existing facilities, and sales of equity securities. Our cash flow from operations and access to capital are subject to a number of variables that may or may not be within our control, including:

- The level of oil and natural gas we are able to produce from existing wells;
- The prices at which our oil and natural gas production is sold;
- The results of our development programs associated with proved and unproved properties;
- Our ability to acquire, locate and produce new economically recoverable reserves;
- Global credit and securities markets; and
- The ability and willingness of lenders and investors to provide capital and the cost of that capital.

If our revenues or the borrowing base under our credit facility decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. Our credit facility restricts our ability to obtain new debt financing outside that facility. There can be no assurance as to the availability or terms of any additional or alternative financing.

If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing on acceptable terms could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to possible writedowns in the carrying value of our properties, a decline in our natural gas and oil reserves as well as our revenues and results of operations.

Changes in financial markets could result in significantly reduced access to public and private capital as well as substantially higher costs of capital if we are able to obtain capital.

Oil and gas activities are capital intensive. Historically, we have obtained equity and debt capital to fund our growth strategy. We may require additional equity capital in order to pursue our business strategy and avoid excessive debt levels. Financial markets often change abruptly and we may not be able to attract investors that would provide equity capital to us at all, or the costs to obtain such capital may be unreasonable. To the extent that we may attract capital, the costs of such capital could increase appreciably and such capital may take forms, such as preferred stock or convertible debt, which would be senior to our common stock. We believe that the ability to attract capital at reasonable costs is critical to our long-term growth strategy, particularly due to the depleting nature of oil and gas operations.

Effects of inflation and pricing may impact our demand for goods and services.

The oil and gas industry is cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put significant pressure on the economic stability and pricing structure within the industry. Demand for equipment and services have caused costs to increase significantly throughout 2009 and 2010. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel.

There are a substantial number of shares of our common stock eligible for future sale in the public market. The sale of a large number of these shares could cause the market price of our common stock to fall.

There were 25,420,842 shares of our common stock outstanding as of March 10, 2011. Members of our management owned approximately 5,597,959 shares of our common stock, representing 22% of our outstanding common stock as of March 10, 2011. Sale of a substantial number of these shares would likely have a significant negative effect on the market price of our common stock, particularly if the sales are made over a short period of time. These shares may be sold publicly pursuant to an effective registration statement with the SEC.

If our shareholders, particularly management and their affiliates, sell a large number of shares of our common stock, the market price of shares of our common stock could decline significantly. Moreover, the perception in the public market that our management and affiliates might sell shares of our common stock could have a depressing effect on the market price of our shares.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Offices

Our principal offices are located at 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, where we occupy approximately 15,800 square feet of office space. Our Northern Region office, consisting of approximately 5,000 square feet, is located at 475 17th Street, Suite 1210, Denver, Colorado 80202. Our Williston office consists of approximately 4,000 square feet and is located at 1407 West Dakota Parkway, Williston, North Dakota 58801.

Oil and Gas Reserve Information

All of our oil and gas reserves are located in the United States. Unaudited information concerning the estimated net quantities of all of our proved reserves and the standardized measure of future net cash flows from the reserves is presented in Note N to the Consolidated Financial Statements. The reserve estimates have been prepared by Cawley, Gillespie & Associates, Inc., an independent petroleum engineering firm. We have no long-term supply or similar agreements with foreign governments or authorities.

Set forth below is a summary of our oil and gas reserves as of January 1, 2011. We did not provide any reserve information to any federal agencies in 2010 other than to the SEC.

	Oil (Mbbl)	Gas (Mmcf)	Present Value Discounted at 10% ($M)(1)
Proved developed	11,231	39,097	$ 308,113
Proved undeveloped	3,162	18,457	70,186
Total Proved	14,393	57,554	$ 378,299

Oil and Gas Reserve Quantities

	Oil (Mbbl)	Gas (Mmcf)
Proved reserve quantities, January 1, 2010	11,419	55,436
Purchases of minerals-in-place	531	1,388
Extensions and discoveries	1,553	1,390
Production	(1,060)	(4,789)
Revisions of quantity estimates	1,950	4,129
Proved reserve quantities, December 31, 2010	14,393	57,554
Proved developed reserve quantities		
January 1, 2010	9,221	38,138
December 31, 2010	11,231	39,097

(1) Present Value Discounted at 10% ("PV10") is a Non-GAAP measure that differs from the GAAP measure "standardized measure of discounted future net cash flows" in that PV10 is calculated without regard to future income taxes. Management believes that the presentation of PV10 value is relevant and useful to our investors because it presents the estimated discounted future net cash flows attributable to our estimated proved reserves independent of our income tax attributes, thereby isolating the intrinsic value of the estimated future cash flows attributable to our reserves. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, we believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies. For these reasons, management uses, and believes the industry generally uses, the PV10 measure in evaluating and comparing acquisition candidates and assessing the potential return on investment related to investments in oil and natural gas properties.

PV10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP. For presentation of the standardized measure of discounted future net cash flows, please see "Note N: Supplemental Financial Information for Oil and Gas Producing Activities - Unaudited" in the Notes to the Consolidated Financial Statements in Part II, Item 8 in this report. The table below ("Non-GAAP Reconciliation") provides a reconciliation of PV10 to the standardized measure of discounted future net cash flows.

Partnership Operations and Reserves as of January 1, 2011 (not included above):

The reserve quantities and values set forth above do not include our interest in two affiliated partnerships.

We hold a 30% partnership interest in SBE Partners, LP ("SBE Partners") which owns interests in the Giddings field (as discussed further below in "Description of Noteworthy Properties"). In addition, we hold direct working interests in producing oil and gas properties located throughout Oklahoma and we also hold the general partner interest in OKLA Energy Partners, LP ("OKLA") which owns a larger interest in those same producing oil and gas properties. Our 2% partnership interest in OKLA reverts to 35.66% if the limited partner realizes a contractually specified rate of return.

The following table represents our estimated share (excluding our reversionary interests) of the affiliated partnerships' reserves and estimated present value of future net income discounted at 10% (in thousands), using SEC guidelines.

	Affiliated Partnership Reserves		
	Oil (Mbbl)	Gas (Mmcf)	Present Value Discounted at 10% ($M)(1)
Proved developed	45	6,993	$ 11,471
Proved undeveloped	7	861	578
Total	52	7,854	$ 12,049

(1) See footnote (1) to the table immediately above.

Non-GAAP Reconciliation

The following table reconciles our direct interest in oil and gas reserves (in thousands):

Present value of estimated future net revenues (PV10)	$ 378,299
Future income taxes, discounted at 10%	(101,284)
Standardized measure of discounted future net cash flows	$ 277,015

The following table reconciles our indirect interest, through our affiliated partnerships, in oil and gas reserves (in thousands):

Present value of estimated future net revenues (PV10)	$ 12,049
Future income taxes, discounted at 10%	(3,981)
Standardized measure of discounted future net cash flows	$ 8,068

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and the interpretation thereof. As a result, estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of the estimates, as well as economic factors such as change in product prices, may require revision of such estimates. Accordingly, oil and natural gas quantities ultimately recovered will vary from reserve estimates.

Proved Undeveloped Reserves

From January 1, 2010 to January 1, 2011, our proved undeveloped reserves ("PUDs") increased 23% from 5,081,000 BOE to 6,238,000 BOE, or an increase of 1,157,000 BOE. This increase was attributable primarily to successful drilling activity and property acquisitions made during 2010 in the Bakken Shale trend of North Dakota and the Giddings field in Texas. We added 956,000 BOE as a result of successful drilling in 2010 and the commensurate PUDs associated with such drilling. As a result of acquisitions during 2010, we added 76,000 BOE. There were zero BOE that were no longer deemed to be economic PUDs at year-end. Reserves of 972,000 BOE were moved from the PUD reserve category to the proved developed category through the drilling of 35 gross wells. We incurred approximately $11.7 million in capital expenditures during 2010 in converting these 35 gross PUD wells to the proved developed reserve category. The remaining change in PUDs of 1,097,000 BOE was a result of increased prices and performance revisions over the time period. Based on our 2010 year end independent engineering reserve report, we plan to drill all of our individual PUD drilling locations within five years.

Preparation of Reserve Estimates

We have engaged an independent petroleum engineering consulting firm, Cawley Gillespie & Associates, Inc. ("CG&A"), to prepare our annual reserve estimates and have relied on their expertise to ensure that our reserve estimates are prepared in compliance with SEC guidelines.

The technical person primarily responsible for the preparation of the reserve report is Mr. Robert Ravnaas, Executive Vice President at CG&A. He earned a Bachelor's of Science degree with special honors in Chemical Engineering from the University of Colorado at Boulder in 1979, and a Master's of Science degree in Petroleum Engineering from the University of Texas at Austin in 1981. Mr. Ravnaas is a Registered Professional Engineer in Texas and has more than 30 years of experience in the estimation and evaluation of oil and gas reserves. He is also a member of the Society of Petroleum Geologists, and Society of Professional Well Log Analysts.

Our Executive Vice President, Engineering and Acquisitions, who is a qualified reserve estimator and auditor, is primarily responsible for overseeing our independent petroleum engineering firm during the preparation of our reserve report. His professional qualifications meet or exceed the qualifications of reserve estimators and auditors set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers. His qualifications include: Bachelor's of Science degree in Petroleum Engineering from the University of Wyoming, 1986; Master's of Business Administration degree from University of Denver, 1988; member of the Society of Petroleum Engineers since 1985; and more than 23 years of practical experience in estimating and evaluating reserve information with more than five years of those being in charge of estimating and evaluating reserves.

We maintain adequate and effective internal controls over our reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are technical information, financial data, ownership interest, and production data. The relevant field and reservoir technical information, which is updated annually, is assessed for validity when our independent petroleum engineering firm has technical meetings with our engineers, geologist, operations and land personnel. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and our own set of internal controls over financial reporting. Internal controls over financial reporting are assessed for effectiveness annually using criteria set forth in *Internal Control – Integrated Framework*, issued by the *Committee of Sponsoring Organizations of the Treadway Commission*. All current financial data such as commodity prices, lease operating expenses, production taxes and field level commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to our internal controls over financial reporting, and they are incorporated in our reserve database as well and verified internally by us to ensure their accuracy and completeness. Once the reserve database has been updated with current information, and the relevant technical support material has been assembled, our independent engineering firm meets with our technical personnel to review field performance and future development plans in order to further verify the validity of estimates. Following these reviews the reserve database is furnished to CG&A so that it can prepare its independent reserve estimates and final report. The reserve estimates prepared by CG&A are reviewed and compared to our internal estimates by our Executive Vice President, Engineering and Acquisitions and staff in our reservoir engineering department. Material reserve estimation differences are reviewed between CG&A's reserve estimates and our internally prepared reserves on a case-by-case basis. An iterative process between CG&A and us regarding any significant differences allows for additional data to be provided in order to address the differences. If the supporting documentation will not justify any additional changes, the CG&A reserves are accepted. In the event that additional data supports a reserve estimation adjustment, CG&A will analyze the additional data, and may make any changes it deems necessary. Additional data is usually comprised of updated production information on new wells. Once the review is completed and all material differences are reconciled, the reserve report is finalized and our reserve database is updated with the final estimates provided by CG&A. Access to our reserve database is restricted to specific members of our reservoir engineering department.

Net Oil and Gas Production, Average Price and Average Production Cost

The net quantities of oil and gas produced and sold by us for each of the three years ended December 31, 2010 the average sales price per unit sold and the average production cost per unit are presented below.

	2010	2009	2008
Oil Production (MBbls)	1,060	851	743
Gas Production (MMcf)	4,789	4,944	2,962
Total Production (MBOE)*	1,858	1,675	1,236
Average sales price (net of hedging):			
Oil per Bbl	$ 70.33	$ 61.09	$ 82.42
Gas per Mcf	$ 5.30	$ 3.97	$ 8.12
BOE	$ 53.78	$ 42.76	$ 68.96
Production cost per BOE	$ 11.27	$ 11.20	$ 18.53

* Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (1 BOE).

Our oil production is sold to large petroleum purchasers. Due to the quality and location of our crude oil production, we may receive a discount or premium from index prices or "posted" prices in the area. Our gas production is sold primarily to pipelines and/or gas marketers under short-term contracts at prices which are tied to the "spot" market for gas sold in the area. Natural gas liquids have been converted to Mcf in the table above.

In 2010, two purchasers each accounted for 12% of our consolidated oil and gas revenues and one purchaser accounted for 11%. In 2009, one purchaser accounted for 17% of our consolidated oil and gas revenues, two purchasers accounted for 15% each of our consolidated oil and gas revenues, and one more accounted for 11%. In 2008, one purchaser accounted for 16% of our consolidated oil and gas revenues, two more accounted for 11% each and two purchasers accounted for 10% each of our consolidated oil and gas revenues. No other single purchaser accounted for 10% or more of our oil and gas revenues in 2010, 2009 or 2008. There are adequate alternate purchasers of our production such that we believe the loss of one or more of the above purchasers would not have a material adverse effect on our results of operations or cash flows.

Gross and Net Productive Wells

As of December 31, 2010, our total gross and net productive wells were as follows:

Productive Wells *

Oil		Gas		Total	
Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
802.0	283.0	447.0	200.0	1,249.0	483.0

* A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractions of working interests we own in gross wells. Productive wells are producing wells plus shut-in wells we deem capable of production. Horizontal re-entries of existing wells do not increase a well total above one gross well.

Gross and Net Developed and Undeveloped Acres

As of December 31, 2010, we had total gross and net developed and undeveloped leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated or permitted by state regulatory authorities.

Gross acres are those acres in which working interest is owned. The number of net acres represents the sum of fraction working interests we own in gross acres.

	Developed		Undeveloped		Total	
State	Gross	Net	Gross	Net	Gross	Net
Texas	119,536	64,699	58,556	28,869	178,092	93,568
N. Dakota	60,820	21,997	108,628	35,340	169,448	57,337
Colorado	5,279	4,058	45,554	21,259	50,833	25,317
Oklahoma	54,573	10,468	321	16	54,894	10,484
Alabama	42,480	21,240	—	—	42,480	21,240
Louisiana	31,707	11,083	5,134	2,959	36,841	14,042
Montana	9,715	6,255	10,786	3,591	20,501	9,846
All Others	4,796	3,686	80	52	4,876	3,738
Total	328,906	143,486	229,059	92,086	557,965	235,572

Exploratory Wells and Development Wells

Set forth below for the three years ended December 31, 2010 is information concerning the number of wells we drilled during the years indicated.

	Net Exploratory Wells Drilled		Net Development Wells Drilled		Total Net Productive and Dry Wells Drilled
Year	Productive	Dry	Productive	Dry	
2010	0.48	—	5.82	0.52	6.82
2009	—	0.12	5.61	—	5.73
2008	0.09	1.00	9.72	1.96	12.77

Present Activities

At March 10, 2011, we had 61 gross (3.95 net) wells in the process of drilling or completing.

Supply Contracts or Agreements

As of December 31, 2010, we were not obligated to provide any fixed or determinable quantities of oil and gas in the future under any existing contracts or agreements, beyond the short-term contracts customary in division orders and off lease marketing agreements with the industry. We also engage in hedging activities as discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Description of Noteworthy Properties

We are the operator of properties containing approximately 75% of our proved oil and gas reserves. As operator we are able to directly influence exploration, development and production operations. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price fluctuations, and thus provide a foundation for our technical staff to pursue the development of our undeveloped acreage, further develop our existing properties and also generate new projects that we believe have the potential to increase our share value. Although, we believe that many of our existing fields have additional exploration and exploitation opportunities, these opportunities are held by continuing production operations and therefore we have deferred certain projects in favor of development drilling associated with our Bakken and Eagle Ford shale, as further discussed below. As common in the industry we participate in non-operated properties on a selective basis; our non-operating participation decisions are dependent on the technical and economic nature of the projects and the operating expertise and financial standing of the operators. The following is a description of certain of our noteworthy operated and non-operated producing oil and gas properties.

Bakken Shale and Three Forks Formations, Williston Basin Overview– We believe the Bakken Shale and Three Forks formations in the Williston Basin represent a large North American oil deposit. A report issued by the United States Geological Survey, or USGS, in April 2008 classified the Bakken formation as the largest continuous oil accumulation ever assessed by it in the contiguous United States. Our Williston Basin, Bakken Shale properties are located primarily in Mountrail and Williams Counties, North Dakota and in Roosevelt and Richland Counties, Montana. We presently have working interests in approximately 44,000 net acres of which, 24,000 net acres are in Williams County, 11,000 net acres are in Mountrail County and 9,000 net acres are in Roosevelt and Richland Counties. As further discussed below, we have been involved in a non-operated joint venture with Slawson Exploration Company ("Slawson") primarily in Mountrail County North Dakota, since 2007. Drilling activities in this joint venture increased appreciably over 2009 and 2010. Consistent with our operating strategy, during 2009 and 2010, we assembled acreage positions in Williams County, North Dakota and in Eastern Montana. At present, we anticipate operating the majority of spacing units across our acreage, outside of Mountrail County, and we continue to lease or otherwise acquire or trade for acreage within these project areas. At present we are running one rig in Williams county and eastern Montana and plan to bring on a second and third rig during 2011 depending on drilling rig availability.

Williams County, North Dakota - Our Williams County project area is comprised of 24,000 net acres, representing a 47.5% working interest where we have lease positions in eighty-two 1,280 acre spacing units. We originated the project and brought in industry partners on a promoted basis. We retained operations within a specified area of mutual interest. Drilling began in the project area in late 2010. We have drilled three operated wells and participated on one non-operated well. These wells are all in varying stages of completion and production operations.

Roosevelt and Richland Counties, Montana - In eastern Montana, we have acquired approximately 9,000 net acres where we are the operator of sixteen 1,280 acre units and have non-operated interests in several additional units. To date we have participated in three non-operated units, two of which are producing and the other one is waiting on hydraulic fracturing. We have also initiated our operated drilling program where we have drilled with the Wheeler Ranch 9-16, which is a vertical Ratcliffe proved undeveloped location awaiting completion and we are currently drilling our first middle Bakken well.

Bakken Non-Operated Joint Venture, North Dakota - Our principal drilling activities in our Bakken non-operated joint venture are conducted through Slawson Exploration Company, Inc., but we also participate in this area with several other industry participants. We have varying working interests in the 11,000 net acres ranging from 10% to 18% in Montrail and nearby counties. To date, over 80 joint venture wells have been drilled by Slawson and we also have nominal interests in over 240 wells with other operators that are producing or are in various stages of drilling and completion. For the quarter ended December 31, 2010, the total production net to our interest in the Bakken trend was approximately 1,171 BOE/day and was approximately 93% oil.

Other Williston Basin Fields - We also operate other fields in Montana and North Dakota, including the Fairview, Fort Gilbert and Mondak Fields in Richland County, Montana, the Froid South Field in Roosevelt County, Montana and the Starbuck Madison Unit, Southwest Starbuck Field, the Landa, Northeast Landa, Sherman and Wayne Fields in Bottineau County, North Dakota. The Montana fields are comprised of 12 gross producing wells from the Mission Canyon interval through the Red River interval. We have an average working interest of 72% with a 61% net revenue interest in these fields. The Froid area has become prospective for Bakken formation production with recent well activity in the area and we control five potential 1,280 acre drilling units and have working interests in two possible additional drilling units. The Sherman/Wayne Fields consist of 20 gross producing wells, which produce from the Mississippian Wayne interval. We have an average working interest in the fields of 80%, with an average net revenue interest of 70%. The Landa/Northeast Landa area has 15 gross producing wells from the Spearfish and Madison intervals. We have a 92% average working interest and a 78% average net revenue interest in these wells. The Starbuck Madison Unit and Southwest Starbuck Field have been unitized and water-flood operations are underway. We operate the units and at the Starbuck Madison Unit have an average working interest of approximately 96% and an average net revenue interest of 81%. At Southwest Starbuck, we have a 98% working interest and a 75% net revenue interest. These two water-floods had production net to our interest of 59 BOE/day (100% oil) for the quarter ended December 31, 2010. For the same period, the production net to our interest in the remaining Williston Basin Fields, including those mentioned above but excluding the Bakken and Starbuck areas, was approximately 405 BOE/day (93% oil).

Eagle Ford Shale Trend - Our Eagle Ford properties are located in Atascosa, Fayette, Gonzales and McMullen counties of Texas. In southwest Fayette County, we have entered into agreements with an industry partner, which established an area of mutual interest, resulted in a cash payment of $20 million for a 50% undivided interest in our acreage, provides for the drilling and completion of six wells, where we retain a 50% interest, without cost to us and further provides us with a retained overriding royalty interest. The agreement also provides for additional leasing. Our net acreage position in the Eagle Ford Trend totals approximately 21,000 acres. Our initial drilling unit is the 900 acre Flatonia East Unit, located in southwest

Fayette County, Texas. We have drilled and cased our initial well in the unit and are currently drilling the second unit well. We have a 50% working interest in this drilling unit and we are the operator for the entire project. Our net working interests in our Eagle Ford acreage range from 32.5% to 65%.

Giddings Field - Our Giddings Field properties are located in Brazos, Burleson, Fayette, Grimes, Lee, Montgomery and Washington Counties, Texas. We operate all but two of these properties, which consist of 68 gross wells that are producing from the Cretaceous Austin Chalk interval. All of the wells are horizontal producers that initially flow at high rates and subsequently produce through rod pumps, compression, and other production methods. We have an average direct working interest of 36% and an average net revenue interest of 28% in this field. In addition, we are the general partner and 30% owner of a limited partnership that owns an average 56% working interest with an average 43% net revenue interest in the Giddings Field. Our acreage position is 35,804 net acres, with approximately 29,406 net acres held directly and approximately 6,398 net acres held through our interest in the limited partnership. From 2007 to early 2010, when we suspended our drilling operations due to low gas prices, we drilled 16 wells with a 100% success rate. We have 20 remaining Austin Chalk drilling locations and believe the acreage is prospective for the Yegua, Georgetown and Eagle Ford formations. Production from the Giddings Field is primarily gas and for the quarter ended December 31, 2010, the production net to our interest in the Giddings Field was approximately 7,440 Mcfe/day and was approximately 96% gas. An additional 2,479 Mcfe/day (96% gas) was attributable to our share of the limited partnership. Our 2010 acquisition in Giddings and nearby fields was located primarily in Brazos and Madison counties, Texas. This property consists of 40 producers with all but three being operated by the Company. Production is from horizontal and vertical wells in the Austin Chalk, Buda and Woodbine formations. Our average working interest is 44% with an average net revenue interest of 32%. We are evaluating the acreage for possible Austin Chalk and Woodbine drilling opportunities. For the quarter ended December 31, 2010 our net production from these properties was approximately 252 BOE/day (77% oil).

St. Martinville Field - Our St. Martinville Field is located in St. Martin Parish, Louisiana. The field consists of 12 gross producing wells, which produce from numerous Miocene sand intervals. The wells are on rod-pump or electric submersible pumps. We operate the field and have an average working interest of 97%. We own the majority of the minerals resulting in a net revenue interest of approximately 91%. The Conoco Fee A-53 was drilled and completed during the fourth quarter of 2010 and commenced production in early 2011. We continue to work the 3-D seismic and subsurface geologic well control and expect to identify additional drilling locations. For the quarter ended December 31, 2010, the production net to our interest in this field was approximately 137 BOE/day (100% oil).

Eloi Bay Field Complex - Our Eloi Bay complex is located in Louisiana state waters offshore St. Bernard Parish, Louisiana in five to 10 feet of water. This non-operated complex has 54 gross producing wells. Our working interests in these wells vary between 12% and 50%. Across the complex as a whole, our average working interest is 46% and our average net revenue interest is 39%. For the quarter ended December 31, 2010, the production net to our interests in the complex was approximately 372 BOE/day (100% oil).

Quarantine Bay Field - Our Quarantine Bay Field is located in Louisiana State waters offshore Plaquemines Parish, Louisiana in six to 15 feet of water. The majority of field pay zones have been developed at depths above 10,500 feet. At present, the field has 32 gross producing wells. We have an average working interest in these wells of 7% and an average net revenue interest of 5%. However, we have a 33% working interest in deeper potential which are generally below 11,500 feet but are further defined in assignments. Our smaller working interest in the shallow production provides cost effective access to production facilities. We believe significant exploration potential exists below field pays. For the quarter ended December 31, 2010, the production net to our interest in this field was approximately 42 BOE/day (99% oil).

South Texas – Our south Texas fields include the Odem Field, located in San Patricio County; the Driscoll Field, located in Duval County; and the Chittim Ranch Field, located in Maverick County. Productive formations include the Frio/Miocene, Jackson/Yegua and Glen Rose intervals. The fields produce with the aid of rod pumps, gas lift and low pressure gathering systems. We operate these fields and our working interests in them range from 44% to 98% and our net revenue interests range from 35% to 86%. For the quarter ended December 31, 2010, the production net to our interest in these fields was approximately 445 BOE/day (43% oil).

West Texas – Our west Texas and New Mexico fields include our Harris Field, located in Gaines County, Texas; our MAK Field, located in Andrews County, Texas; and other fields located in Eddy and Lea Counties, New Mexico. Productive formations include the San Andres, Spraberry, Seven Rivers, Queen and Grayburg intervals. The fields produce with the aid of rod pumps. We operate these fields and our working interests in them range from 68% to 100% and our net revenue interests range from 52% to 78%. For the quarter ended December 31, 2010, the production net to our interests in these properties was approximately 235 BOE/day (79% oil).

Title to Properties

It is customary in the oil and gas industry to make a limited review of title to undeveloped oil and gas leases at the time they are acquired. It is also customary to obtain more extensive title examinations prior to the commencement of drilling operations on undeveloped leases or prior to the acquisition of producing oil and gas properties. With respect to the future acquisition of both undeveloped and proved properties, we plan to conduct title examinations on such properties in a manner consistent with industry and banking practices. We have obtained title opinions, title reports or otherwise conducted title investigations covering substantially all of our producing properties and believe we have satisfactory title to such properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, overriding royalty interests, and other burdens which we believe do not materially interfere with the use or affect the value of such properties. Substantially all of our oil and gas properties are and may continue to be mortgaged to secure borrowings under bank credit facilities (see Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources").

Item 3. Legal Proceedings

We are not party to, nor are any of our properties subject to, any material pending legal proceedings. We know of no material legal proceedings contemplated or threatened against us.

Item 4. Reserved

Executive Officers of the Registrant

The following table sets forth certain information as of March 10, 2011, regarding the executive officers of GeoResources, Inc.:

Name	Age	Position(s) with the Company
Frank A. Lodzinski	61	President and Chief Executive Officer
Robert J. Anderson	49	Executive Vice President, Engineering and Acquisitions
Collis P. Chandler	42	Executive Vice President and Chief Operating Officer - Northern Region
Howard E. Ehler	66	Vice President and Chief Financial Officer
Francis M. Mury	59	Executive Vice President and Chief Operating Officer - Southern Region

Frank A. Lodzinski has been President, Chief Executive Officer and Director of the Company since 2007. He has 40 years of oil and gas industry experience. In 1984, he formed Energy Resource Associates, Inc., which acquired controlling interests in oil and gas properties and limited partnerships. Subsequently, certain assets were sold and in 1992 the partnership interests were exchanged for common shares of Hampton Resources Corporation (NASDAQ: "HPTR"), which Mr. Lodzinski joined as president. In 1995, Hampton was sold to Bellwether Exploration Company. In 1996, he acquired Cliffwood Oil & Gas Corporation and in 1997, Cliffwood shareholders acquired controlling interest in Texoil, Inc. (NASDAQ: "TXLI"), where Mr. Lodzinski served as CEO and President. In 2001, Texoil was sold to Ocean Energy, Inc. Mr. Lodzinski was then appointed CEO and President of AROC, Inc., which was a financially distressed company. He and his management team took the company private, recapitalized the company and implemented a turn-around and liquidation plan. In late 2003, AROC completed an asset monetization, which resulted in a sizable liquidity event for preferred and common shareholders. Mr. Lodzinski subsequently formed Southern Bay Energy, LLC, and in late 2005 acquired certain assets from AROC. Southern Bay was merged into GeoResources in April 2007 ("Merger"). Mr. Lodzinski holds a BSBA degree in Accounting and Finance from Wayne State University in Detroit, Michigan and is a Certified Public Accountant.

Robert J. Anderson is Executive Vice President, Engineering and Acquisitions. He has been employed by the Company since April 2007. He is a Petroleum Engineer and has been active in the oil and gas industry since 1987 with diversified domestic and international experience for both major oil companies (ARCO International/Vastar Resources) and independent oil companies (Hunt Oil/Huguton Energy/Anadarko Petroleum). From October 2000 through February 2004, he was employed by Anadarko Petroleum Corporation as a petroleum engineer. From March 2004 through December 2004 he was employed by AROC, Inc. as Vice President, Acquisitions and Divestitures. He joined Southern Bay Energy, LLC in January 2005 as Vice President, Acquisitions and Divestitures. His professional experience includes acquisition evaluation, reservoir and production engineering and field development, and project economics, budgeting and planning. Mr. Anderson's domestic acquisition and divestiture experiences include the Gulf Coast of Texas and Louisiana (offshore and onshore), east and west Texas, north Louisiana, Mid-Continent and the Rockies. His international experience includes Canada, South America and Russia. He has an undergraduate degree in Petroleum Engineering from the University of Wyoming (1986) and also holds an MBA, Corporate Finance, from the University of Denver (1988).

Collis P. Chandler, III has been Executive Vice President and Chief Operating Officer - Northern Region and Director of the Company since April 2007. He has been President and sole owner of Chandler Energy, LLC since its inception in July 2000. From 1988 to July 2000, Mr. Chandler served as Vice President of The Chandler Company, a privately-held exploration company operating primarily in the Rocky Mountains. His responsibilities over the 12-year period included involvement in exploration, prospect generation, acquisition, structure and promotion as well as direct responsibility for all land functions including contract compliance, lease acquisition and administration. Mr. Chandler received a Bachelor of Science Degree from the University of Colorado, Boulder, in 1992.

Howard E. Ehler is our Chief Financial Officer and Principle Accounting Officer and has been employed by the Company since April 2007. He was employed as Vice President and Chief Financial Officer of AROC, Inc. from May 2001 through December 2004. Since January 2005, Mr. Ehler has been employed by Southern Bay Energy, LLC as Vice President and Chief Financial Officer. He previously served as Vice President of Finance and Chief Financial Officer for Midland Resources, Inc. from March 1997 through October 1998. From November 1999 through April 2001 he performed independent accounting and auditing services in oil and gas as a sole practitioner in public accounting. He was employed in public accounting with various firms for over 21 years, including practice with Grant Thornton, where he was admitted to the partnership. He has substantive experience in oil and gas banking, finance, accounting and reporting. In addition, his experience includes partnership administration, tax, budgets and forecasts and cash management. Mr. Ehler holds an Accounting Degree from Texas Tech University (1966) and has been a Certified Public Accountant since 1970.

Francis M. Mury has been Executive Vice President and Chief Operating Officer - Southern Region of the Company since April 2007. He has been active in the oil and gas industry since 1974. He was employed by AROC, Inc. as Executive Vice President from May 2001 through December 2004. Since January 2005, he has been employed by Southern Bay Energy LLC as Executive Vice President. Mr. Mury worked for Texaco, Inc. from July 1974 through March 1979, ending his tenure there as a petroleum field engineer. From April 1979 through December 1985, he worked for Wainoco Oil & Gas as a production engineer and drilling superintendent. From January 1986 to November 1989 he worked for Diasu Oil & Gas as an operations manager. He has worked with Mr. Lodzinski since 1989, including at Hampton Resources Corporation, where he served as Vice President – Operations from January 1992 through May 1995, and Texoil, Inc., where he served as Executive Vice President from November 1997 through February 2001. His experience extends to all facets of petroleum engineering, including reservoir engineering, drilling and production operations and further into petroleum economics, geology, geophysics, land and joint operations. Geographical areas of experience include the Gulf Coast (offshore and onshore), east and west Texas, Mid-Continent, Florida, New Mexico, Oklahoma, Wyoming, Pennsylvania and Michigan. Mr. Mury received a degree in Computer Science (1974) from Nicholls State University, Thibodeaux, Louisiana.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock trades on The NASDAQ Global Select Market under the Symbol "GEOI." The following table sets forth, for each of the periods indicated, the high and low sales prices per share of our common stock as reported by The NASDAQ Global Select Market. These trade prices may represent prices between dealers and do not include retail markup, markdowns or commissions.

	High	Low
2010		
Fourth Quarter	$ 23.44	$ 15.83
Third Quarter	$ 16.43	$ 13.01
Second Quarter	$ 17.87	$ 13.32
First Quarter	$ 16.25	$ 11.29
2009		
Fourth Quarter	$ 13.85	$ 10.09
Third Quarter	$ 12.19	$ 8.82
Second Quarter	$ 10.79	$ 6.44
First Quarter	$ 9.74	$ 4.97

As of March 10, 2011, there were approximately 550 holders of record of our common stock. We believe that there are also approximately 8,000 additional beneficial owners of our common stock held in "street name."

Dividend Policy

We have never paid dividends on our common stock and do not intend to pay a dividend in the foreseeable future. Furthermore, our amended credit agreement with our bank restricts the payment of cash dividends. The payment of future cash dividends on common stock, if any, will be reviewed periodically by our Board of Directors and will depend upon, among other things, our financial condition, funds available for operations, the amount of anticipated capital and other expenditures, our future business prospects and any restrictions imposed by our present or future bank credit arrangements.

Equity Compensation Plan Information

The following sets forth information as of March 10, 2011, concerning our compensation plan under which shares of our common stock are authorized for issuance.

PLAN CATEGORY	NUMBER OF SECURITIES TO BE ISSUED UPON EXERCISE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	WEIGHTED AVERAGE EXERCISE PRICE OF OUTSTANDING OPTIONS, WARRANTS AND RIGHTS	NUMBER OF SECURITIES REMAINING AVAILABLE FOR FUTURE ISSUANCE
Equity compensation plans approved by security holders:			
Amended and Restated 2004 Employees' Stock Incentive Plan	2,000,000	$ 9.70	447,500
Equity compensation plans not approved by security holders:	N/A	N/A	N/A

No employee options were exercised during 2008 nor 2009. In 2010, options for 33,150 shares of our common stock were exercised.

Item 6. Selected Financial Data

The following selected financial data contained in this table should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our consolidated financial statements and the accompanying notes thereto included elsewhere in this report.

	Year ended December 31 2010	2009	2008	2007	2006
A. Summary of Operating Data					
Production					
Oil (Mbls)	1,060	851	743	392	184
Natural gas (MMcf)	4,789	4,944	2,962	1,648	577
Barrel of oil equivalent (MBOE)	1,858	1,675	1,236	667	280
Average realized prices:					
Oil (per bbl)	$ 70.33	$ 61.09	$ 82.42	$ 67.20	$ 54.61
Natural gas (per Mcf)	$ 5.30	$ 3.97	$ 8.12	$ 6.19	$ 6.83
B. Summary of Operations (in thousands, except per share amounts):					
Oil and gas revenues	$ 99,913	$ 71,618	$ 85,263	$ 36,518	$ 13,978
Total revenues	107,017	80,998	94,606	40,115	16,805
Lease operation and workover expenses	22,906	21,570	26,432	12,910	4,636
Production taxes	6,589	4,193	7,517	2,880	1,066
Depletion, depreciation and amortization	24,686	22,409	16,007	7,507	3,382
Pretax earnings	35,254	14,842	21,291	7,949	4,280
Income tax expense (1)	11,923	5,067	7,769	4,880	33
Net income	23,331	9,775	13,522	3,069	4,247
Net income per share:					
Basic	$ 1.18	$ 0.59	$ 0.87	$ 0.25	$ 0.87
Diluted	$ 1.16	$ 0.59	$ 0.86	$ 0.25	$ 0.87
C. Summary Balance Sheet Data at Year End (in thousands):					
Net property, plant and equipment	$ 302,891	$ 248,386	$ 181,580	$ 181,443	$ 31,229
Total assets	359,690	304,297	243,534	240,358	50,667
Working capital	8,292	11,946	11,883	7,371	(1,689)
Long-term debt	87,000	69,000	40,000	96,000	5,000
Total equity	201,735	174,677	140,995	68,032	23,660
D. Adjusted EBITDAX (in thousands) (2):					
Net Income	$ 23,331	$ 9,775	$ 13,522	$ 3,069	$ 4,247
Interest expense	4,712	4,984	4,820	1,916	288
Income tax expense (1)	11,923	5,067	7,769	4,880	33
Depletion, depreciation and amortization	24,686	22,409	16,007	7,507	3,382
Impairment expense	3,440	2,795	8,339	—	184
Exploration expense	849	1,406	2,592	153	558
Hedge ineffectiveness	(891)	137	(123)	287	(393)
(Gain)/ loss on derivative contracts	(2)	162	563	—	—
Non-cash compensation expense	1,071	1,424	661	553	422
Adjusted EBITDAX	**$ 69,119**	**$ 48,159**	**$ 54,150**	**$ 18,365**	**$ 8,721**

(1) The 2006 consolidated financial statements were those of Southern Bay, which, as a partnership, was generally not subject to federal and state income taxes.

(2) Adjusted EBITDAX is a Non-GAAP measure that differs from the GAAP measure of Net Income. Adjusted EBITDAX is calculated as shown above. Adjusted EBITDAX should not be considered as an alternative to net income (as an indicator of operating performance) or as an alternative to cash flow (as a measure of liquidity or ability to service debt obligations) and is not in accordance with, nor superior to, generally accepted accounting principles, but provides additional information for evaluation of our operating performance.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with the consolidated financial statements and related notes thereto reflected in the index to the consolidated financial statements in this report.

General

We are an independent oil and gas company engaged in the acquisition, development and production of oil and gas reserves in multiple basins. As further discussed in this report, future growth in assets, earnings, cash flows and share values will be dependent upon our ability to acquire, discover and develop commercial quantities of oil and gas reserves that can be produced at a profit, and assemble an oil and gas reserve base with a market value exceeding its acquisition, development and production costs.

Our strategy includes a combination of acquisition, development and exploration activities. Historically, we have shifted our emphasis among these basic activities to take advantage of changing market conditions and to facilitate profitable growth. The majority of our efforts are currently focused on developing our oil-weighted acreage positions in the Bakken trend of Montana and North Dakota and the Eagle Ford trend of Texas. In addition, it is essential that, over time, our personnel expand our current projects and/or generate additional projects so we have the potential of economically replacing our production and increasing our proved reserves. Following is a brief outline of our current plans:

- Accelerate the development of our acreage positions in the Bakken and Eagle Ford trends;
- Expand our acreage positions and drilling inventory.
- Solicit industry partners, on a promoted basis, where we can retain operations and control large acreage positions in order to diversify, enhance economics and generate operating fees;
- Generate additional exploration and development projects;
- Acquire oil and gas properties with producing reserves and development and exploration potential, within our focus areas;
- Selectively divest assets to high-grade our producing property portfolio and to lower corporate wide "per-unit" operating and administrative costs, and focus attention on existing fields and new projects with greater development and exploitation potential; and
- Obtain additional capital, as needed, through the issuance of equity securities and/or through debt financing.

While the impact and success of our corporate plans cannot be predicted with accuracy, our goal is to replace production and further increase our reserve base at an acquisition or finding cost that will yield attractive rates of return.

In addition to our fundamental business strategy, we intend to pursue corporate acquisitions and mergers. We believe that a corporate acquisition or merger could potentially accelerate growth, increase market visibility and realize operating and administrative benefits. Accordingly, we intend to consider any such opportunities which may become available that we consider beneficial to our stockholders. The primary financial considerations in the evaluation of any such potential transactions include, but are not limited to: (1) the potential to increase assets in a core area, (2) the opportunity to increase our earnings and cash flow on a per share basis, (3) development and exploration potential, and (4) realization of administrative savings. Further, we believe a corporate acquisition could lead to increased visibility in the market place, greater trading volume and therefore greater shareholder liquidity and possibly access to capital with lower costs.

Recent Property Acquisitions

During 2010 we continued our drilling programs and expanded our acreage positions. We also acquired producing and undeveloped properties, principally in the Bakken Shale trend in the Williston Basin, North Dakota and in the Giddings field, Texas. A summary of our 2010 activities is as follows:

- In October 2009, the Company initiated a leasing program in Williams County, North Dakota with the objective of establishing a significant operated position in the Bakken shale trend. In February 2010, the Company entered into agreements with two unaffiliated third parties under which we sold each of them an interest in existing acreage and they agreed with us to acquire additional acreage and jointly develop the project area. Cash proceeds to us totaled approximately $20 million and we retained a 47.5% working interest in the project area. The agreement also provided for up to $10 million ($4.75 million net to the Company) of additional joint leasing in a contractually specified area of mutual interest ("AMI"). As of December 31, 2010 our net acreage position in the project area totals approximately 24,000 acres. For accounting purposes the Company uses the cost recovery method; under this method proceeds from joint owners have been recorded in the balance sheet as a reduction to the carrying value of the unproved properties.

- On July 30, 2010 the Company closed an acquisition of producing oil and gas properties located in the Giddings field of Central Texas. The purchase price was $16.6 million plus closing adjustments for normal operations activity. The acquisition covered approximately 9,700 net acres and was funded through borrowings under our credit facility.
- In September 2010, we Company entered into an agreement with an unaffiliated third party to jointly acquire and develop mineral leases in the Eagle Ford shale trend of Texas. As part of this agreement, the Company sold a 50% working interest in its acreage for $20 million. For accounting purposes, the Company uses the cost recovery method; under this method, proceeds from joint owners are recorded in the balance sheet as a reduction of the carrying value of unproved properties. The purchaser also agreed to pay the drilling costs for the first six wells to be drilled in a contractually specified AMI. The agreement also provides for an additional $20 million ($10 million net to the Company) for additional leasing within the AMI. Subsequent to the initial closing, the Company and the joint owners have continued to acquire leases within the AMI pursuant to the terms of the agreement.
- In November 2010, the Company purchased an 86.67% membership interest in Trigon Energy Partners, LLC ("Trigon"), which owns undeveloped leases in the Eagle Ford shale trend of Texas for approximately $11.8 million. The Company fully consolidated Trigon and recorded a non-controlling minority interest of $2.2 million at December 31, 2010. For the year ended December 31, 2010, Trigon did not generate any revenue or net income. The Company's share of Trigon's undeveloped leases is included the Eagle Ford acreage totals throughout this report.

Results of Operations

Year ended December 31, 2010, compared to the year ended December 31, 2009.

We realized net income of $23.3 million and $9.8 million for the years ended December 31, 2010, and 2009, respectively. The $13.6 million increase in net income resulted primarily from the following factors.

Net amounts contributing to increase (decrease) in net income (in 000s):

Oil and gas sales	28,295
Lease operating expenses	(2,181)
Production taxes	(2,396)
Exploration expense	557
Re-engineering and workovers	845
Impairment of oil and gas properties	(645)
General & administrative expense (G&A)	(974)
Depletion, depreciation and amortization expenses (DD&A)	(2,277)
Net interest income (expense)	(176)
Hedge ineffectiveness	1,028
Gain / (loss) on derivative contracts	164
Gain / (loss) on sale of property	(402)
Other income - net	(1,426)
Income before income taxes	20,412
Provision for income taxes	(6,856)
Net income	13,556

The following discussion applies to the above changes.

Oil and Natural Gas Sales. Oil and gas revenues increased by $28.3 million, or 40%. Increased commodity prices accounted for $16.1 million of the increase and increased production volumes accounted for the remaining $12.2 million. Increased oil production was attributable primarily to new wells drilled during 2010 and 2009, as well as recent acquisitions, partially offset by normal production declines on previously existing wells. Price and production comparisons are set forth in the following table.

	Percent increase (decrease)	Year Ended December 31, 2010	2009
Oil Production (MBbl)	25%	1,060	851
Gas Production (MMcf)	(3%)	4,789	4,944
Barrel of Oil Equivalent (MBOE)	11%	1,858	1,675
Average Price Oil Before Hedge Settlements (per Bbl)	28%	$ 72.05	$ 56.37
Average Realized Price Oil (per Bbl)	15%	$ 70.33	$ 61.09
Average Price Gas Before Hedge Settlements (per Mcf)	24%	$ 4.07	$ 3.28
Average Realized Price Gas (per Mcf)	34%	$ 5.30	$ 3.97

Lease Operating Expenses - Lease operating expenses ("LOE") increased from approximately $18.8 million for 2009 to $20.9 million for 2010, an increase of $2.2 million or 12%. Our lease operating expenditures have increased primarily due to increased production; on a unit-of-production basis, LOE costs have slightly increased by $.07 per BOE to $11.27 per BOE.

Re-engineering and workover - Re-engineering and workover costs decreased from $2.8 million to $2.0 million primarily due to a major re-engineering and workover program concluded in 2009.

Production Taxes - Production taxes increased by $2.4 million or 57%, due to increased production volumes and revenues. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenues before the effects of hedging. Our production taxes for 2010 and 2009 were 6.6% and 6.5%, respectively, of oil and gas sales before the effects of hedging.

Exploration and Impairment Costs - Our exploration costs were $849,000 for December 31, 2010 and $1.4 million for 2009. We incurred residual costs of $192,000 during 2010 on an exploratory well deemed to be a dry hole prior to December 31, 2009. The remaining $657,000 were geological and geophysical costs. In 2009, we incurred $1.3 million for geological and geophysical data and incurred dry hole and other costs of $83,000. We recorded non-cash impairments charges of $3.4 million and $2.8 million in 2010 and 2009, respectively, due to the write-down of proved properties. The book value of these properties exceeded our estimate of future undiscounted cash flows as a direct result of the decline in our estimate of future natural gas prices.

General and Administrative Expenses - Our G&A costs increased from $8.5 million in 2009 to $9.5 million in 2010, an increase of $1.0 million, or 11% as a result of increases in salaries and other overhead expenses offset by a decrease in non-cash charges related to our stock-based compensation.

Depreciation, Depletion and Amortization - DD&A expense increased by $2.3 million or 10% due to higher capitalized costs and higher production. Capitalized costs increased due to acquisitions of additional property interests in both the Giddings field and Bakken Shale and continued successful drilling in the Bakken. On a units-of- production basis, DD&A per BOE decreased slightly from $13.38 in 2009 to $13.29 in 2010.

Interest Income and Expense - Interest expense decreased by $272,000 due to capitalized interest. We capitalized interest of $234,000 in 2010 and none in 2009. Our average outstanding debt was $73.6 million and $74.2 million during 2010 and 2009, respectively. The effective annual interest rate was 6.7% for 2010 and 2009. The interest rates reflect the effects of interest swap contract settlements, as well as loan fees. Interest income decreased by $448,000 during 2010 compared to 2009 due to $415,000 of interest earned on severance tax refunds in 2009 and none in 2010.

Hedge Ineffectiveness - During 2010 the gain from hedge ineffectiveness was $891,000, compared to a loss of $137,000 for 2009. The ineffectiveness in 2010 relates to our gas derivatives accounted for as a cash flow hedges, which increased in value. The change in the ineffective portion of these derivatives was a gain. During 2009, our derivatives accounted for as cash flow hedges decreased in value; therefore, the change in the ineffective portion of these derivatives was a loss.

Loss on Derivative Contracts - In December, 2008, we split up a $50 million notional value interest rate swap that was previously accounted for as a cash flow hedge. The swap was split up into a $10 million swap and $40 million notional amount swap. We continued hedge accounting for the $40 million swap and accounted for the $10 million swap as a trading security. These swap contracts expired in October 2010. We recognized gains of $2,000 in 2010 and losses of $162,000 in 2009.

Other Income - Other income decreased by $1.4 million in 2010 compared to 2009 due to a decreases in partnership income and partnership management fees, offset by an increase in severance tax refunds. During 2010, we recorded partnership income of $2.2 million and during 2009 we recorded $4.3 million. The 2009 partnership income included $1.3 million of gains on sales of properties to the general partner and $1.3 million of refunds on severance taxes for which the state of Texas granted exemptions. These decreases in partnership income were partially offset by our increased share of revenues and expenses from the partnership. As a result of the property sales, our interest in revenues and expenses from most of the properties in SBE Partners, LP increased from 2% to 30% during the second quarter of 2009. While we expect partnership income to continue to be significant due to our increased interest in SBE Partners we do not expect the partnership to record significant gains similar to those in 2009 on property sales in the future. Since the partnership, subsequent to the sale, held a smaller interest in its properties, our partnership management fee decreased by $457,000. During 2009 we recorded severance tax refunds of $571,000 on qualifying high cost gas wells in Texas. During 2010 we recorded severance tax refunds of $1.2 million related to both high cost gas wells in Texas and certain qualifying oil wells in Louisiana.

Income Tax Expense - Income tax expense for 2010 was $11.9 million compared to $5.1 million for 2009. Our income tax expense increased due to higher pre-tax earnings. Our effective tax rate for 2010 and 2009 were 33.82% and 34.14%, respectively. The lower rate for 2010 is attributable to statutory deductions for excess depletion and domestic production activities, both of which represent permanent differences between financial statement income and taxable income.

Year ended December 31, 2009, compared to the year ended December 31, 2008.

We recorded net income of $9.8 million and $13.5 million for the years ended December 31, 2009, and 2008, respectively. The $3.7 million decrease in net income resulted primarily from the following factors.

Net amounts contributing to increase (decrease) in net income (in 000s):		
Oil and gas sales	$	(13,645)
Lease operating expenses		4,151
Production taxes		3,324
Exploration expense		1,186
Re-engineering and workovers		711
Impairment of oil and gas properties		5,544
General & administrative expense (G&A)		(1,332)
Depletion, depreciation and amortization expenses (DD&A)		(6,402)
Net interest income (expense)		(317)
Hedge ineffectiveness		(260)
Gain / (loss) on derivative contracts		401
Gain / (loss) on sale of property		(3,007)
Other income - net		3,197
Income before income taxes		(6,449)
Provision for income taxes		2,702
Net income	$	(3,747)

The following discussion applies to the above changes.

Oil and Natural Gas Sales. Oil and gas revenues decreased $13.6 million, or 16%; however, as shown in the table below, sales volumes increased significantly. Properties acquired from SBE Partners LP in May 2009, increased revenue by $6.5 million and production by approximately 2,122,000 Mcf of gas and 5,000 barrels of oil during 2009. Properties acquired in the May 2009 Bakken acquisition accounted for revenue of $3.7 million and production of approximately 59,000 barrels of oil and 13,000 Mcf of gas during 2009. These increases were offset by significant price declines in the average prices received for oil and natural gas. Price and production comparisons are set forth in the following table:

	Percent increase (decrease)	Year Ended December 31, 2009	2008
Oil Production (MBbl)	15%	851	743
Gas Production (MMcf)	67%	4,944	2,962
Barrel of Oil Equivalent (MBOE)	36%	1,675	1,236
Average Price Oil Before Hedge Settlements (per Bbl)	(41%)	$ 56.37	$ 94.88
Average Realized Price Oil (per Bbl)	(26%)	$ 61.09	$ 82.42
Average Price Gas Before Hedge Settlements (per Mcf)	(61%)	$ 3.28	$ 8.36
Average Realized Price Gas (per Mcf)	(51%)	$ 3.97	$ 8.12

Lease Operating Expenses - Lease operating expenses ("LOE") decreased from approximately $22.9 million for 2008 to $18.8 million for 2009, a decrease of $4.1 million or 18%. On a unit-of-production basis, barrel of oil equivalent ("BOE") LOE costs decreased by $7.33 or 40% due primarily to unprecedented demand for oil field services in 2008 which pushed prices for these services to all time highs during 2008, while the prices for these services decreased during 2009. Additionally, we acquired properties in the SBE Partners and Bakken acquisitions with lower per unit operating costs thus further decreasing our lease operating costs on a per unit basis.

Re-engineering and workover - Our re-engineering and workover costs decreased by $711,000, or 20%, from $3.5 million in 2008 to $2.8 million in 2009, due to a cost containment strategy implemented during the lower pricing environment of 2009.

Production Taxes - Our severance taxes decreased by $3.3 million or 44%, due to decreased oil and gas revenues as well as to tax exemptions granted by the state of Texas for certain high cost drilling wells. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We seek to take full advantage of all credits and exemptions allowed in our various jurisdictions. Our production taxes for 2009 and 2008 were 6.5% and 7.9%, respectively, of oil and gas sales before the effects of hedging.

Exploration and Impairment Costs - Our exploration costs were $1.4 million for 2009 and $2.6 million for 2008. In 2009, we incurred $1.3 million for geological and geophysical data and incurred dry hole and other costs of $83,000. In 2008, we drilled four gross exploratory dry holes with costs incurred through December 31, 2008 of $1.9 million, wrote-off undeveloped properties with a cost of $483,000 and incurred geological costs of $161,000. We recorded non-cash impairment charges of $2.8 million and $8.3 million in 2009 and 2008, respectively due to the write-down of proved properties. The book value of these properties exceeded our estimate of future cash flows.

General and Administrative Expenses - Our G&A costs increased from $7.2 million in 2008 to $8.5 million in 2009, an increase of $1.3 million, or 19%. This was due to overall business expansion as well as increases in salaries and other overhead expenses, partially offset by cost reductions resulting from the centralization of certain job functions. The total non-cash charges related to stock-based compensation included in G&A expense for the years ended December 31, 2009 and 2008 were $1.4 million and $661,000, respectively.

Depreciation, Depletion and Amortization - DD&A increased from $16.0 million in 2008 to $22.4 million in 2009, for an increase of $6.4 million, or 40%. This was due to the substantial increase in capitalized cost attributable to acquisitions, as well as to our active drilling program.

Interest Income and Expense - Interest expense increased by $164,000 due to slightly higher average debt levels during 2009 compared to 2008, partially offset by lower interest rates. Our average outstanding debt was $74.2 million and $67.2 million during 2009 and 2008, respectively. The effective annual interest rates were 6.7% and 7.2%, for 2009 and 2008, respectively. These rates reflect the effects of interest swap contract settlements, as well as loan fees. Interest income decreased by $153,000 during 2009 compared to 2008 due to lower interest rates on average invested cash balances.

Hedge Ineffectiveness - During 2009, the loss from hedge ineffectiveness was $137,000, compared to a gain of $123,000 for 2008. In 2009, our derivatives that are accounted for as cash flow hedges decreased in value from a net asset to a net liability; therefore, the ineffective portion of these derivatives resulted in a loss. In 2008, our derivatives that were accounted for as cash flow hedges increased in value. Therefore, the ineffective portion of the derivatives resulted in a gain.

Loss on Derivative Contracts - In December, 2008, we split up a $50 million notional value interest rate swap that was previously accounted for as a cash flow hedge. The swap was split up into a $10 million swap and $40 million notional amount swap. We continued hedge accounting for the $40 million swap and accounted for the $10 million swap as a trading security. We recognized losses of $162,000 and $563,000 in 2009 and 2008, respectively, related to this swap.

Other Income - Other income increased by $3.2 million during 2009 compared to 2008. Partnership income increased by $3.2 million, from $1.1 million in 2008 to $4.3 million in 2009. Gains on sales of properties to the general partner accounted for $1.3 million of this increase and refunds of severance taxes on wells for which the state of Texas granted exemptions accounted for $1.3 million of the increase. The remaining increase in partnership income resulted from our earning a larger share of partnership income.

Income Tax Expense - Our provision for income taxes for 2009 was $5.1 million compared to $7.8 million for 2008. This decrease of $2.7 million was due to lower pretax income, as well as slightly lower rates. Our effective tax rates for 2009 and 2008 were 34.14% and 36.50%, respectively.

Hedging Activities

Management attempts to reduce our sensitivity to oil and gas price volatility and secure favorable debt financing terms by entering into hedging transactions which may include fixed price swaps, price collars, puts and other derivatives. We believe our hedging strategy should result in greater predictability of internally generated funds, which in turn can be dedicated to capital development projects and corporate obligations. The following is a summary of our current oil and gas hedge contracts as of March 10, 2010.

	Total Annual Volume	Floor Price	Ceiling / Swap Price
Crude Oil Contracts (Bbls):			
Swap contracts:			
2011	282,000		$ 74.370
2011	84,000		$ 88.450
2011	120,000		$ 85.050
2011	60,000		$ 85.160
2012	120,000		$ 86.850
2012	120,000		$ 87.220
Costless collars contracts:			
2011 (added Jan. 31, 2011)	55,000	$ 85.00	$ 106.080
2012 (added Jan. 31, 2011)	120,000	$ 85.00	$ 110.000
Natural Gas Contracts (Mmbtu)			
Swap contracts:			
2011	210,000		$ 6.065
2011	630,000		$ 6.450
2012	150,000		$ 6.450
2012	450,000		$ 6.415
2012 (added Jan. 31, 2011)	900,000		$ 4.850
2013 (added Jan. 31, 2011)	225,000		$ 4.850
Costless collars contracts:			
2011	1,079,000	$ 7.00	$ 9.200

The fair market value of our gas hedge contracts in place at December 31, 2010 and 2009, were assets of $5.1 million and $2.1 million, respectively, of which $4.3 million and $764,000 were classified as current assets, respectively. The fair market value of our oil hedge contracts in place at December 31, 2010 and 2009 were liabilities of $9.1 million and $6.4 million, respectively, of which $7.4 million and $3.2 million were classified as current liabilities, respectively. For the year ended December 31, 2010 and 2009, we recognized, in oil and gas revenues, realized cash settlement gains on commodity derivatives of $4.1 million and $7.4 million, respectively. Realized hedge settlement losses included in oil and gas revenues were $10.0 million for 2008. Due to hedge ineffectiveness on hedge contracts during 2009 we recognized a non-cash loss of $137,000. During 2010 and 2008, we recognized non-cash gains due to hedge ineffectiveness of $891,000 and $123,000, respectively.

Based on the estimated fair market value of our derivatives, designated as hedges at December 31, 2010, we expect to reclassify net losses on commodity derivatives of $3.2 million into earnings from accumulated other comprehensive income (loss) during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

At December 31, 2010, a 10% increase in per unit commodity prices would cause the total fair value liability of our commodity derivative financial instruments to increase by $8.3 million to $12.3 million. A 10% decrease in per unit commodity prices would cause the fair value liability to change to an asset of $4.3 million due to an estimated $8.3 million decrease in the net liability. There would also be a similar increase or decrease in other comprehensive income (loss) included in total equity in the balance sheet. Since we have designated all of our commodity derivative instruments as cash flow hedges and therefore the change in market value of the effective portion of the hedge is included in other comprehensive income, a 10% change in fair value would not have a significant effect on net income.

Additionally, should commodity prices increase in the future periods by 10%, our realized settlement losses on commodity derivatives, which are included in oil and gas revenues, would increase by approximately $9.0 million in 2011. If commodity prices decrease in the future by 10%, our realized settlement losses on commodity hedges would decrease by $2.7 million in 2011.

In connection with the borrowing from our bank to fund the October, 2007 AROC acquisition, we also entered into a two-year interest rate swap contract on $50 million of the debt, designed to protect us against interest rate increases. During 2008, we extended the term of this interest rate swap through October, 2010, and broke the swap up into two pieces, a $40 million swap and a $10 million swap. We accounted for the $40 million swap as a cash flow hedge while the $10 million swap was accounted for as a trading security. The value of these swaps at December 31, 2009 was a liability of $1.6 million all of which is classified as a current liability. The value of these swaps at December 31, 2008, was $2.8 million of which $1.6 million was classified as a current liability. We recognized a gain of $2,000 on the $10 million swap during 2010. We also recognized losses of $162,000 and $563,000 during 2009 and 2008, respectively, on the $10 million swap.

Hedging commodity prices for a portion of our production is a fundamental part of our corporate financial management. We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities of our production. In implementing our hedging strategy we seek to:

- Effectively manage cash flow to minimize price volatility and generate internal funds available for operations, capital development projects and additional acquisitions; and
- Ensure our ability to support our exploration activities as well as administrative and debt service obligation.

Estimating the fair value of derivative instruments requires complex calculations, including the use of a discounted cash flow technique, estimates of risk and volatility, and subjective judgment in selecting an appropriate discount rate. In addition, the calculations use future market commodity prices which, although posted for trading purposes, are merely the market consensus of forecasted price trends. The results of the fair value calculation cannot be expected to represent exactly the fair value of our commodity hedges. We currently obtain fair value positions from our counterparties and compare that value to our internally calculated value. We believe that our practice of comparing our value to that of our counterparties, who are more specialized and knowledgeable in preparing these complex calculations, reduces our risk of error and approximates the fair value of the contracts, as the fair value obtained from our counterparties would be the cost to us to terminate a contract at that point in time.

Commitments and Contingencies

We have the following contractual obligations and commitments as of December 31, 2010:

	Payments Due by Year (in thousands)			
	Long-term Debt [1]	Commodity Derivatives [2]	Operating Leases	Asset Retirement Obligations [3]
2011	$ —	$ 7,433	$ 329	$ 25
2012	$ 91,418	1,650	340	28
2013	—	—	348	6
2014	—	—	357	5
2015	—	—	197	6
Thereafter	—	—	10	27,621
	$ 91,418	$ 9,083	$ 1,581	$ 27,691

(1) Long-term debt is the outstanding principal amount and interest under our Credit Agreement at December 31, 2010. Interest is calculated using the annual interest rate in effect at December 31, 2010 of 2.77%. In January 2011 the Long Term debt was fully paid down from a portion of the proceeds raised in a public offering of our common stock. The commitments under the Credit Agreement continue to remain in place. This table does not include future commitment fees, or other fees because we cannot determine with accuracy the timing of future loans, advances or repayments.

(2) Represents the estimated future payments under our oil and natural gas derivative contracts based on the future market prices as of December 31, 2010. These amounts will change as oil and natural gas commodity prices change. The estimated fair market value of all of our oil and natural gas commodity derivatives at December 31, 2010, was a net liability of $4.0 million.

(3) Represents the estimates of future asset retirement obligations on an undiscounted basis. The discounted present value of the asset retirement obligations at December 31, 2010 is $7.1 million.

Administrative and Operating Costs

On an ongoing basis, we focus on cost-containment efforts related to administrative and operating costs. However, we must continue to attract and retain competent management, technical and administrative personnel to successfully pursue our business strategy and fulfill our contractual obligations. Our industry has experienced a shortage of such personnel over the past few years, and we expect this shortage to continue as long as oil prices and demand for services in our key operating areas remain at historically high levels.

Liquidity and Capital Resources

We expect to finance future acquisition, development and exploration activities through available working capital, cash flows from operating activities, our bank credit facility, sale of non-strategic assets, various means of corporate and project finance and possibly through issuance of additional debt and or/equity securities. In addition, we intend to continue to partially finance our drilling activities through the sale of participations to industry or institutional partners on a promoted basis, whereby we may earn working interests in reserves and production greater than our proportionate capital costs. Financing activities during 2010 resulted in a net increase in our debt of $18 million from the outstanding debt of $69 million at December 31, 2009. We borrowed $38 million to fund the acquisitions of producing properties and acreage in our Bakken and Eagle Ford areas and made principal debt payments of $20 million. Financing activities during 2009 resulted in a net increase in debt of $29 million from the outstanding debt of $40 million at December 31, 2008. During the second quarter of 2009, we borrowed an additional $64 million to fund the SBE Partners and Bakken acquisitions. During the fourth quarter of 2009, we completed a public offering of common stock and repaid $35 million in debt using the $33 million net proceeds from the stock issue plus $2 million in cash flows from operations.

	December 31,		
	2010	2009	2008
		(Millions)	
Balances outstanding, beginning of year	$ 69.0	$ 40.0	$ 96.0
Borrowings	38.0	64.0	—
Repayments of debt	(20.0)	(35.0)	(56.0)
Balances outstanding, end of year	$ 87.0	$ 69.0	$ 40.0
Issuance of common stock	$ —	$ 33.1	$ 32.2

Credit Facility

At December 31, 2010, we had a $145 million borrowing base, with available borrowing capacity of $58 million in accordance with our Amended Credit Agreement with our bank. The borrowing base is redetermined in May and November of each year. As a result of the successful public stock offering in January 2011, we have reduced our outstanding line of credit debt to zero and now have $145 million available under the facility.

Cash Flows From Operating Activities

For 2010, net cash provided by operating activities was $59.5 million, an increase of $35.5 million from 2009. We believe that we can continue to generate cash flows sufficient to allow us to continue with our planned capital expenditures program which will replace our reserves and increase our oil and gas production, assuming commodity prices do not decrease substantially. For 2009 as compared to 2008, net cash provided by operating activities decreased by $18.3 million. This decrease was directly attributable to the decrease in commodity prices, partially offset by decreases in lease operating expenses, re-engineering and workover expenses and other cost control measures.

Cash Flows From Investing Activities

Cash applied to oil and gas capital expenditures was $82.0 million for 2010, $89.4 million for 2009, and $51.8 million for 2008. In 2010, 2009 and 2008, we realized cash of $1.0 million, $2.0 million and $26.8 million, respectively, from the sale of non-core properties. During 2010, we completed one acquisition for a combined cost of $16.6 million, which was financed with borrowings from our credit facility. During 2009, we completed two acquisitions for a combined cost of $56.7 million. During 2008, we invested $978,000 in newly formed oil and gas limited partnership for which we are the general partner.

Capital Expenditures Budget

We continue to expand our portfolio of drilling and development projects and therefore have increased our projected drilling and development expenditures. As summarized below, we estimate our capital budget for 2011 will total $114.0 million. While the table includes the bulk of our currently identified drilling for 2011, we are constantly working on developing and acquiring new opportunities. A benefit of our property portfolio is that it consists of relatively new acreage positions and therefore we generally have two to five years to drill the bulk of our undeveloped leases. In addition, many of our drilling opportunities, including the bulk of our gas drilling locations, are "held by production" or long term leases and therefore not subject to lease expiration or significant future incremental carrying costs. Accordingly, we have a substantial ability to adjust our capital spending as industry circumstances dictate or as opportunities arise.

We have initiated drilling on our operated Bakken acreage in the Williston Basin and our operated Eagle Ford acreage in Texas and our Bakken non-operated holdings continue to be actively developed. Those projects represent the bulk of our planned capital expenditures for 2011, as set forth in the table below. However, we may shift our expenditures between geographic areas and projects in an attempt to maximize cash flow and take advantage of regional differences in net commodity prices and service costs or other matters we deem of significance.

While industry circumstances may require us to make capital expenditures adjustments, it is our current intent to accelerate our Bakken and Eagle Ford drilling and further expand our acreage. To a lesser extent, we intend to drill certain locations in the Austin Chalk and certain of our prospects on the Gulf Coast, but those projects could be deferred in favor of increased activity in other areas or so long as low natural gas prices prevail.

The projects, estimated costs and timing of actual expenditures are subject to significant change as we continue to technically and economically evaluate existing and alternative projects, as we further expand our portfolio, and as industry conditions dictate. Estimated expenditures are also subject to significant change. There can be no assurance that all of the projects identified and summarized in the table below will remain viable and therefore certain projects may be sold or abandoned by us. However, in the opinion of management, at present, we have sufficient cash flows and liquidity to fulfill lease obligations or otherwise maintain all material mineral leases. Our current estimate of our capital expenditure spending for 2011 is as follows:

	($ in Millions)	Percent of Capital Budget
Bakken - operated [1]	$ 29.5	26%
Bakken - non-operated [2]	21.0	18%
Eagle Ford [3]	15.8	14%
Giddings Field [4]	8.3	7%
Louisiana [5]	7.8	7%
Acreage and seismic [6]	25.0	22%
Other drilling operations	6.6	6%
Total	**$ 114.0**	100%

Notes:

(1) Includes approximately $26.0 million allocated to our operated Bakken drilling project in Williams County, North Dakota. The remaining $3.5 million represents planned drilling on Bakken spacing units we control in eastern Montana. In Williams County, North Dakota, we expect to complete drilling our initial three wells in the first quarter of 2011. We are further planning to resume drilling in the late Spring of 2011 after a reasonable time to complete the wells and evaluate performance. Depending on drilling results, our current plan calls for adding a second rig in mid-2011.

(2) Represents continuation of our non-operated program. Approximately $17.5 million represents activities in Mountrail County, North Dakota and $3.5 million represents planned drilling in eastern Montana.

(3) Represents our net estimated cost of drilling 13 planned wells where we have a 50% carried interest in six wells at no cost to us.

(4) Represents our net estimated cost of drilling three wells in the Giddings Field, Texas.

(5) Represents our net estimated cost of drilling seven wells in the St. Martinville Field and one well at Quarantine Bay, Louisiana.

(6) Includes approximately $22.0 million allocated to additional acreage and $3.0 million allocated to seismic activities. We intend to continue expanding our acreage positions in our focus areas and therefore, with success, our capital spending could exceed the amounts shown above.

Pending success, continuing favorable industry and economic conditions and availability of equipment and services among other factors, our current estimate of capital expenditures for 2012 is approximately $173.0 million, largely directed toward continued Bakken and expanded Eagle Ford drilling and incremental acreage acquisitions.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our consolidated financial statements. The preparation of these statements requires us to make certain assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. A summary of our significant accounting policies is detailed in Note A to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Oil and Gas Properties

We use the successful efforts method of accounting for oil and gas operations. Under this method, costs to acquire oil and gas properties, drill successful exploratory wells, drill and equip development wells, and install production facilities are capitalized. Exploration costs, including unsuccessful exploratory wells, geological, geophysical as well as cost of carrying and retaining unproved properties are charged to operations as incurred. Depreciation, depletion and amortization ("DD&A") of the capitalized costs associated with proved oil and gas properties are computed using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by our independent petroleum engineers. Oil and gas properties are periodically assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. Long-lived assets committed by management for disposal are accounted for at the lower of cost or fair value, less transaction costs. All of our properties are located within the continental United States and the Gulf of Mexico.

Oil and Natural Gas Reserve Quantities

Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion, impairment of our oil and natural gas properties, and asset retirement obligations. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of our reserve estimates is a function of:

- The quality and quantity of available data;
- The interpretation of that data;
- The accuracy of various mandated economic assumptions; and
- The judgments of the persons preparing the estimates.

Our proved reserves information included in this report is based on estimates prepared by our independent petroleum engineers, Cawley, Gillespie & Associates, Inc. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of January 1, 2011. Estimates prepared by others may be higher or lower than our estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. We make revisions to reserve estimates throughout the year as additional information becomes available. We make changes to depletion rates, impairment calculations, and asset retirement obligations in the same period that changes to reserve estimates are made.

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

Our rate of recording DD&A is dependent upon our estimates of total proved and proved developed reserves, which estimates incorporate various assumptions and future projections. If the estimates of total proved or proved developed reserves decline, the rate at which we record DD&A expense increases, reducing our net income. Such a decline in reserves may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

Impairment of Oil and Gas Properties

We review the value of our oil and gas properties whenever management determines that events and circumstances relating to the significant deterioration in the future cash flow expected to be generated by an asset group indicate that the recorded carrying value of the properties may not be recoverable. This process is performed no less frequently than at the end of each calendar quarter. Impairments of producing properties are determined by comparing the pretax future net undiscounted cash flows to the net capitalized costs at the end of each period. If the net capitalized costs exceeds undiscounted future cash flows, the cost of the property is written down to "fair value," which is determined based on expected future cash flows using discounted rates commensurate with the risks involved, using prices and costs consistent with those used for internal decision making relative to acquisitions and divestitures. During 2010, we recorded impairments of $3.4 million on proved properties. These impairments are described in Note A – Organization and Summary of Significant Accounting Policies in the notes to the Consolidated Financial Statements. Different pricing assumptions or discount rates could result in a different calculation of impairment. The significant assumptions used in the current period's calculation are described in Note G – Fair Value Disclosures in the notes to the Consolidated Financial Statement. We provide for impairments on significant undeveloped properties when we determine that the property will not be developed or a permanent impairment in value has occurred.

Asset Retirement Obligation

Our asset retirement obligations ("AROs") consist primarily of estimated future costs before considering estimated salvage value associated with the plugging and abandonment of oil and gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A over the life of the oil and gas field.

Derivative Instruments and Hedging Activity

We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We use hedging to help ensure that we have adequate cash flows to fund our capital expenditure programs and manage price risks and returns on some of our acquisitions and drilling programs. Our decision on the quantity and price at which we choose to hedge our production is based, in part, on our view of current and future market conditions. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. We primarily utilize swaps and costless collars, which are placed with major financial institutions. The oil and natural gas reference prices of these commodity derivative contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive. All derivative instruments are recorded on the consolidated balance sheet at fair value. Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For qualifying cash flow hedges, the fair value gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to oil and gas revenues in our consolidated statements of income in the period that the hedged production is delivered. Hedge effectiveness is measured quarterly based on the relative changes in the fair value between the derivative contract and the hedged item over time.

Our costless collars are valued based on the counterparty's marked-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index. Our swaps are valued based on a discounted future cash flow model. Our primary input for the model is the NYMEX futures index. Our model is validated by the counterparty's marked-to-market statements. The discount rate used in determining the fair values of these instruments includes a measure of nonperformance risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control.

Our results of operations each period can be impacted by our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control. If our derivative contracts would not qualify for cash flow hedge treatment, then our consolidated statements of income could include large non-cash fluctuations, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

The use of hedging transactions also involves the risk that the counterparties will be unable to meet the financial terms of such transactions. We evaluate the ability of our counterparties to perform at the inception of a hedging relationship and on a periodic basis as appropriate.

Income Taxes and Uncertain Tax Positions

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

We will consider a tax position settled if the taxing authority has completed its examination, we do not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. We use the benefit recognition model which contains a two-step approach, a more likely than not recognition criteria and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, then we will not record the tax benefit. The amount of interest expense that we recognize related to uncertain tax positions is computed by applying the applicable statutory rate of interest to the difference between the tax position recognized and the amount previously taken or expected to be taken in a tax return.

We are subject to taxation in many jurisdictions, and the calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in various taxing jurisdictions. If we ultimately determine that the payment of these liabilities will be unnecessary, we reverse the liability and recognize a tax benefit during the period in which we determine the liability no longer applies. Conversely, we record additional tax charges in a period in which we determine that a recorded tax liability is less than we expect the ultimate assessment to be.

Revenue Recognition

We predominantly derive our revenue from the sale of produced oil and gas. Revenue is recorded in the month the product is delivered to the purchaser. We receive payment from one to three months after delivery. At the end of each month, we estimate the amount of production delivered to purchasers and the price we will receive. Variances between our estimated revenue and actual payment are recorded in the month the payment is received. Historically, these differences have been insignificant.

Accounting for Business Combinations

Our business has grown substantially through acquisitions, and our business strategy is to continue to pursue acquisitions as opportunities arise. We have accounted for all of our business combinations to date using the purchase method.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets, liabilities and non-controlling interests acquired are measured at their fair value including the recognition of acquisition-related costs and anticipated restructuring costs that are separate from the acquired net assets. The purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to the fair value of assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is recognized immediately to earnings as a gain from bargain purchase. Certain contingent assets acquired and liabilities assumed in a business combination are recognized at fair value on the acquisition date if we can reasonably estimate a fair value during the measurement period.

Determining the fair values of the assets and liabilities acquired involves the use of judgment, since some of the assets and liabilities acquired do not have fair values that are readily determinable. Different techniques may be used to determine fair values, including market prices (where available), appraisals, comparisons to transactions for similar assets and liabilities, and present value of estimated future cash flows, among others. Since these estimates involve the use of significant judgment, they can change as new information becomes available.

Off Balance Sheet Arrangements

We have no off balance sheet arrangements, special purpose entities, financing partnerships or guarantees.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from changes in commodity prices. In the normal course of business, we enter into derivative transactions, including commodity price collars, swaps and floors to mitigate our exposure to commodity price movements. We do not participate in these transactions for trading or speculative purposes. While the use of these arrangements limits the benefit to us of increases in the price of oil and natural gas, it also limits the downside risk of adverse price movements.

The following is a list of contracts outstanding at December 31, 2010:

Transaction Date	Transaction Type	Beginning	Ending	Price Per Unit	Remaining Annual Volumes	Fair Value Outstanding as of December 31, 2010
						(in thousands)
Natural Gas						
October-07	Collar	01/01/11	12/31/11	$7.00 - $9.20	1,079,000	$ 2,688
December-09	Swap	04/01/10	03/31/11	$6.065	210,000	384
December-09	Swap	04/01/11	03/31/12	$6.450	780,000	1,412
December-09	Swap	04/01/12	12/31/12	$6.415	450,000	649
						5,133
Crude Oil						
October-07	Swap	01/01/11	12/31/11	$74.37	282,000	(5,454)
January-10	Swap	01/01/11	12/31/11	$88.45	84,000	(454)
August-10	Swap	09/01/10	12/31/11	$85.05	120,000	(1,023)
August-10	Swap	01/01/12	12/31/12	$86.85	120,000	(850)
October-10	Swap	01/01/11	12/31/11	$85.16	60,000	(502)
October-10	Swap	01/01/12	12/31/12	$87.22	120,000	(800)
						(9,083)
						$ (3,950)

We are exposed to financial risk from changes in interest rates. The long-term debt on our balance sheet of $87 million is the outstanding principal amount under our Second Amended and Restated Credit Agreement which matures in October 2012. In the event we have debt outstanding and interest rates were to rise significantly, our interest expense will increase significantly as well, thereby adversely affecting our profitability. At our 2010 debt level, an increase in annual interest rates of 1% would result in an increase in interest expense of $870,000 and a reduction in net income of approximately $576,000.

Item 8. Financial Statements and Supplementary Data

See "Index to Consolidated Financial Statements and Supplementary Information" of Page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None.

Item 9A. <u>Controls and Procedures</u>

(a) Evaluation of Disclosure Controls and Procedures

In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), our Chief Executive Officer, Chief Financial Officer and other members of management evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of December 31, 2010. Based upon their evaluation of these disclosure controls and procedures, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of December 31, 2010, in ensuring that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive and principal financial officers to allow timely discussion regarding required disclosure.

(b) Management's Report on Internal Control over Financial Reporting

The management of GeoResources, Inc. and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements of external purposes in accordance with generally accepted accounting principles.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2010 using criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2010, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report which is included herein.

(c) Attestation Report of Registered Public Accounting Firm

Board of Directors and Shareholders of GeoResources, Inc.:

We have audited GeoResources Inc.'s (a Colorado corporation) and subsidiaries internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). GeoResources, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on GeoResources, Inc. and subsidiaries' internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, GeoResources, Inc. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of GeoResources, Inc. and subsidiaries as of December 31, 2010 and 2009 and the related consolidated statements of income, equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010, and our report dated March 11, 2011, expressed an unqualified opinion on those consolidated financial statements.

/s/ Grant Thornton LLP
Houston, Texas
March 11, 2011

(d) Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. <u>Other Information</u>

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in our definitive proxy material under the heading "Election of Directors" and "Board of Directors" to be filed with the SEC within 120 days after December 31, 2010.

Item 11. Executive Compensation

The information required by this item is included in our definitive proxy material under the heading "Executive Compensation and Other Transactions" to be filed with the SEC within 120 days after December 31, 2010.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is included in our definitive proxy material under the heading "Security Ownership of Certain Beneficial Owners and Management Related Stockholder Matters" to be filed with the SEC within 120 days after December 31, 2010.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is included in our definitive proxy material under the heading "Certain Relationships and Related Transaction and Director Independence" to be filed with the SEC within 120 days after December 31, 2010.

Item 14. Principal Accountant Fees and Services

The information required by this item is included in our definitive proxy material under the heading "Independent Public Accountants" to be filed with the SEC within 120 days after December 31, 2010.

Item 15. Exhibits and Financial Statement Schedules

EXHIBIT INDEX

FOR

Form 10-K for the year ended December 31, 2010.

Exhibit No.	Description
3.1	Amended and Restated Articles of Incorporation dates June 10, 2003, incorporated by reference to Exhibit 3.1 of Registrant's Form 10-KSB for the year ended December 31, 2003.
3.1(a)	Articles of Amendment to the Articles of Incorporation, incorporated by reference as Annex C to the Registrant's definitive Proxy Statement dated February 23, 2007, and filed with the Commission on February 23, 2007.
3.1(b)	Articles of Amendment to Articles of Incorporation, dated November 6, 2007. (5)
3.2	Bylaws, as amended March 2, 2004, incorporated by reference to Exhibit 3.2 of Registrant's Form 10-KSB for the year ended December 31, 2003.
10.15	Agreement and Plan of Merger dated September 14, 2006, among GeoResources, Inc., Southern Bay Energy Acquisition, LLC, Chandler Acquisition, LLC, Southern Bay Oil & Gas, L.P., Chandler Energy, LLC and PICA Energy, LLC (including Amendment No. 1 dated February 16, 2007). Incorporated by reference as Annex A to the Registrant's Definitive Proxy Statement dated February 23, 2007 and filed with the Commission on February 23, 2007.
10.19	Lease Agreement between AROC, Inc. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090 dated June 7, 2001. (3)
10.20	First Amendment to June 7, 2001 Lease Agreement by and between AROC, Inc. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated November 10, 2003. (3)
10.21	Assignment and Assumption by Southern Bay Energy, L.L.C. of June 7, 2001 Lease Agreement by and between AROC, Inc. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 19, 2005. (3)
10.22	Unconditional Guaranty of June 7, 2001 Lease Agreement by and between Southern Bay Energy, L.L.C. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 19, 2005. (3)
10.23	Second Amendment to June 7, 2001 Lease Agreement by and between Southern Bay Energy, L.L.C. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 19, 2005. (3)
10.24	Third Amendment to June 7, 2001 Lease Agreement by and between Southern Bay Energy, L.L.C. and BGK Texas Property Management, Inc. for 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated April 9, 2007. (3)
10.26	January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street Building, Suite 860, 475 17th Street, Denver, Colorado 80202. (3)
10.27	First Amendment to January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street, Suite 860, Denver, Colorado 80202, dated September 28, 2001. (3)
10.28	Second Amendment to January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street, Suite 860, Denver, Colorado 80202, dated October 23, 2002. (3)
10.29	Third Amendment to January 31, 2000 Office Building Lease by and between 475-17th Street, CO. and Collis P. Chandler III for 475 17th Street, Suite 860, Denver, Colorado 80202, dated June 28, 2004. (3)
10.30	Credit Agreement dated September 26, 2007 between the Registrant and Wachovia Bank National Association. (2)
10.31	Limited Partner Interest Purchase and Sale Agreement dated October 16, 2007 between the Registrant and TIFD III-X, LLC. (2)

Exhibit No.	Description
10.32	Amended and Restated Credit Agreement dated October 16, 2007 between the Registrant and Wachovia Bank National Association. (2)
10.33	Amended and Restated Credit Agreement dated October 16, 2007 between the Registrant and Wachovia Bank National Association. (2)
10.34	Form of Purchase Agreement. (4)
10.35	Form of Warrant. (4)
10.36	Form of Registration Rights Agreement. (4)
10.37	Agreement of Limited Partnership for OKLA Energy Partners LP dated May 20, 2008. (6)
10.38	Lease Agreement by and between Southern Bay Energy, L.L.C. and Cypress Court Operating Associates, L.P. for office space at 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated September 25, 2008. (7)
10.39	Purchase and Sale Agreement between SBE Partners LP and Catena Oil and Gas LLC, dated May 29, 2009. (8)
10.40	Consent and Amendment No. 1 to Agreement of Limited Partnership of SBE Partners LP as of May 29, 2009. (8)
10.41	Second Amended and Restated Credit Agreement between the Registrant and Wachovia Bank, National Association as Administrative Agent dated July 13, 2009. (8)
10.42	Consent, Distribution Agreement, and Amendment No. 2 to Agreement of Limited Partnership of SBE Partners LP. (9)
10.43	First Amendment to Lease Agreement by and between Southern Bay Energy, L.L.C. and Cypress Court Operating Associates, Limited Partnership for office space at 110 Cypress Station Drive, Suite 220, Houston, Texas 77090, dated January 29, 2010. (10)
10.44	Exploration and Development Agreement-New Home II Project, between G3 Energy, LLC and Resolute Northern Rockies, LLC, effective February 2, 2010. (11)
10.45	Amendment to Exploration and Development Agreement-New Home II Project, between G3 Energy, LLC and Resolute Northern Rockies, LLC, effective February 2, 2010. (11)
10.46	Purchase and Sale Agreement dated June 25, 2009, by and among Hop-Mar Energy, L.P., Sydri Energy Investments I, Ltd., Snyder Energy Investments, Ltd., Woodbine Energy Partners, L.P. (Sellers) and Southern Bay Energy, LLC (Buyer). (12)
10.47	Participation Agreement-Eagle Ford Project entered into September 29, 2010 between Southern Bay Energy, LLC, Southern Bay Operating, LLC and Ramshorn Investments, Inc. (12)
10.48	Amended and Restated Limited Liability Company Agreement of Trigon Energy Partners LLC dated October 30, 2010. (1)
10.49	Lease Acquisition and Development Agreement By and Between Trigon Energy Partners LLC and CEU Eagle Ford, LLC, dated May 4, 2010. (1)
10.50	Exploration and Development Agreement with Area of Mutual Interest between Slawson Exploration Company, Inc. and G3 Operating, LLC (as successor-in-interest to Chandler Energy, LLC) dated January 1, 2007. Certain portions of this exhibit have been omitted under a request for confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934 and filed separately with the United States Securities and Exchange Commission. (1)
14.1	Code of Business Conduct and Ethics adopted March 2, 2004, incorporated by reference to Exhibit 14.1 of Registrant's Form 10-KSB for fiscal year ended December 31, 2003.
21.1	Subsidiaries of the Registrant. (1)
23.1	Consent of Grant Thornton LLP (for GeoResources, Inc.). (1)
23.2	Consent of Grant Thornton LLP (for SBE Partners LP). (1)
23.3	Consent of Cawley, Gillespie & Associates, Inc. (1)
24.1	Power of Attorney. (included on the signature page hereof)

31.1 Certification of the Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act. (1)

31.2 Certification of the Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act. (1)

32.1 Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act. (Furnished herewith)

32.2 Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act. (Furnished herewith)

99.1 Financial Statements and Report of Independent Certified Public Accountants for SBE Partners LP for the years ended December 31, 2010, 2009 and 2008. (1)

99.2 Report of Cawley, Gillespie & Associates, Inc. dated February 25, 2011. (1)

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(1) Filed herewith.
(2) Filed with the Registrant's Form 10-QSB for the quarter ended September 30, 2007.
(3) Filed with the Registrant's Form 10-QSB for the quarter ended June 30, 2007.
(4) Filed with the Registrant's Form 8-K on June 11, 2008.
(5) Filed with the Registrant's Form 10-KSB for the year ended December 31, 2007.
(6) Filed with the Registrant's Form 10-Q for the quarter ended June 30, 2008.
(7) Filed with the Registrant's Form 10-Q for the quarter ended September 30, 2008.
(8) Filed with the Registrant's Form 10-Q for the quarter ended June 30, 2009.
(9) Filed with the Registrant's Form 10-Q for the quarter ended September 30, 2009.
(10) Filed with the Registrant's Form 10-K for the year ended December 31, 2009.
(11) Filed with the Registrant's Form 10-Q for the quarter ended June 30, 2010.
(12) Filed with the Registrant's Form 10-Q for the quarter ended September 30, 2010.

GEORESOURCES, INC. and SUBSIDIARIES

Index to Consolidated Financial Statements and Supplementary Information

CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of GeoResources, Inc.:

We have audited the accompanying consolidated balance sheets of GeoResources, Inc. (a Colorado corporation) and subsidiaries as of December 31, 2010 and 2009, and the related consolidated statements of income, equity and comprehensive income (loss) and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes, examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GeoResources, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

We also have audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), GeoResources, Inc and subsidiaries' internal control over financial reporting as of December 31, 2010 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 11, 2011 expressed an unqualified opinion that GeoResources, Inc and subsidiaries maintained, in all material respects, effective internal control over financial reporting.

/s/ Grant Thornton LLP
Houston, Texas
March 11, 2011

GEORESOURCES, INC and SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash	$ 9,370	$ 12,660
Accounts receivable		
Oil and gas revenues	17,017	14,860
Joint interest billings and other	16,631	13,734
Affiliated partnerships	969	933
Notes receivable	120	120
Derivative financial instruments	4,282	764
Income taxes receivable	222	2,077
Prepaid expenses and other	2,645	2,297
Total current assets	51,256	47,445
Oil and gas properties, successful efforts method:		
Proved properties	341,582	285,363
Unproved properties	32,403	10,281
Office and other equipment	1,140	828
Land	146	96
	375,271	296,568
Less accumulated depreciation, depletion and amortization	(72,380)	(48,182)
Net property and equipment	302,891	248,386
Equity in oil and gas limited partnerships	2,272	3,532
Derivative financial instruments	851	1,360
Deferred financing costs and other	2,420	3,574
	$ 359,690	$ 304,297

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC and SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	December 31, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 14,616	$ 6,452
Accounts payable to affiliated partnerships	2,931	8,361
Revenue and royalties payable	12,450	13,928
Drilling advances	4,203	390
Accrued expenses	1,331	1,574
Derivative financial instruments	7,433	4,794
Total current liabilities	42,964	35,499
Long-term debt	87,000	69,000
Deferred income taxes	19,289	15,778
Asset retirement obligations	7,052	6,110
Derivative financial instruments	1,650	3,233
Equity:		
Common stock, par value $0.01 per share; authorized 100,000,000 shares; issued and outstanding: 19,726,566 shares in 2010 and 19,705,362 in 2009	197	197
Additional paid-in capital	148,172	146,966
Accumulated other comprehensive income (loss)	(3,000)	(3,288)
Retained earnings	54,133	30,802
Total GeoResources, Inc. stockholders' equity	199,502	174,677
Noncontrolling interest	2,233	—
Total equity	201,735	174,677
	$ 359,690	$ 304,297

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except share and per share amounts)

	Year Ended December 31, 2010	2009	2008
Revenue:			
Oil and gas revenues	$ 99,913	$ 71,618	$ 85,263
Partnership management fees	550	1,007	1,725
Property operating income	1,865	1,710	1,430
Gain on sale of property and equipment	953	1,355	4,362
Partnership income	2,240	4,318	1,061
Interest and other	1,496	990	765
Total revenue	107,017	80,998	94,606
Expenses:			
Lease operating expense	20,944	18,763	22,914
Production taxes	6,589	4,193	7,517
Re-engineering and workovers	1,962	2,807	3,518
Exploration expense	849	1,406	2,592
Impairment of oil and gas properties	3,440	2,795	8,339
General and administrative expense	9,474	8,500	7,168
Depreciation, depletion and amortization	24,686	22,409	16,007
Hedge ineffectiveness	(891)	137	(123)
(Gain) / loss on derivative contracts	(2)	162	563
Interest	4,712	4,984	4,820
Total expense	71,763	66,156	73,315
Income before income taxes	35,254	14,842	21,291
Income taxes:			
Current	8,861	412	866
Deferred	3,062	4,655	6,903
	11,923	5,067	7,769
Net income	$ 23,331	$ 9,775	$ 13,522
Less: Net income attributable to noncontrolling interest	—	—	—
Net income attributable to GeoResources, Inc.	$ 23,331	$ 9,775	$ 13,522
Net income per share (basic)	$ 1.18	$ 0.59	$ 0.87
Net income per share (diluted)	$ 1.16	$ 0.59	$ 0.86
Weighted average shares outstanding:			
Basic	19,720,652	16,532,003	15,598,244
Diluted	20,142,297	16,559,431	15,751,185

The accompanying notes are an integral part of these statements

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY and COMPREHENSIVE INCOME (LOSS)
Years Ended December 31, 2010, 2009 and 2008
(In thousands, except share data)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Non-Controlling Interest	Total
	Shares	Par value					
Balance, January 1, 2008	14,703,383	$ 147	$ 79,690	$ 7,505	$ (19,310)	$ —	$ 68,032
Issuance of common stock							
For cash, net of issuance costs of $2,313	1,533,334	15	32,172				32,187
For services	5,000	—	35				35
Comprehensive income:							
Net income				13,522			13,522
Change in fair market value of hedged positions, net of taxes					20,019		20,019
Hedging losses realized in income, net of taxes					6,574		6,574
Total comprehensive income							40,115
Equity based compensation expense			626				626
Balance, December 31, 2008	**16,241,717**	**162**	**112,523**	**21,027**	**7,283**	**—**	**140,995**
Issuance of common stock							
For cash, net of issuance costs of $2,136	3,450,000	35	33,019				33,054
For services	13,645	—	59				59
Comprehensive income:							
Net income				9,775			9,775
Change in fair market value of hedged positions, net of taxes of $4,357					(7,123)		(7,123)
Hedging gains realized in income, net of taxes of $2,388					(3,448)		(3,448)
Total comprehensive loss							(796)
Equity based compensation expense			1,365				1,365
Balance, December 31, 2009	**19,705,362**	**197**	**146,966**	**30,802**	**(3,288)**	**—**	**174,677**
Exercise of employee stock options							
Cash exercises	13,150	—	135				135
Cashless exercises	8,054	—	2				2
Comprehensive income:							
Net income				23,331			23,331
Change in fair market value of hedged positions, net of taxes of ($1,488)					2,024		2,024
Hedging gains realized in income, net of taxes of $1,048					(1,736)		(1,736)
Total comprehensive loss							23,619
Purchase of Trigon Energy Partners LLC						2,233	2,233
Equity based compensation expense			1,069				1,069
Balance, December 31, 2010	**19,726,566**	**$ 197**	**$ 148,172**	**$ 54,133**	**$ (3,000)**	**$ 2,233**	**$ 201,735**

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2010	2009	2008
Cash flows from operating activities:			
Net income	$ 23,331	$ 9,775	$ 13,522
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	24,686	22,409	16,007
Exploratory dry holes and unproved property impairments	—	—	2,241
Impairment of proved properties	3,440	2,795	8,339
Gain on sale of property and equipment	(953)	(1,355)	(4,362)
Accretion of asset retirement obligations	405	368	391
Unrealized (gain) loss on derivative contracts	(325)	(238)	563
Amortization of loss on cancelled hedges	—	482	—
Hedge ineffectiveness (gain) loss	(891)	137	(123)
Partnership income	(2,240)	(4,318)	(1,061)
Partnership distributions	3,500	2,406	653
Deferred income taxes	3,062	4,655	6,903
Non-cash compensation	1,071	1,424	661
Changes in assets and liabilities:			
Decrease (increase) in accounts receivable	(599)	(7,923)	3,958
Decrease in notes receivable	100	275	480
Decrease (increase) in prepaid expense and other	707	(1,116)	(1,990)
Increase (decrease) in accounts payable and accrued expense	4,237	(5,732)	(3,844)
Net cash provided by operating activities	59,531	24,044	42,338
Cash flows from investing activities:			
Proceeds from sale of property and equipment	1,018	1,991	26,789
Additions to property and equipment, net of cost recoveries of $40,230 in 2010 and none in 2009 and 2008	(70,126)	(89,396)	(51,824)
Investment in oil and gas limited partnership	—	—	(978)
Purchase of Trigon Energy Partners LLC	(11,848)	—	—
Cancellation of hedge contracts	—	—	(2,975)
Net cash used in investing activities	(80,956)	(87,405)	(28,988)
Cash flows from financing activities:			
Issuance of common stock	135	33,054	32,187
Issuance of long-term debt	38,000	64,000	—
Reduction of long-term debt	(20,000)	(35,000)	(56,000)
Net cash provided by (used in) financing activities	18,135	62,054	(23,813)
Net increase (decrease) in cash and cash equivalents	(3,290)	(1,307)	(10,463)
Cash and cash equivalents at beginning of period	12,660	13,967	24,430
Cash and cash equivalents at end of period	$ 9,370	$ 12,660	$ 13,967
Supplementary information:			
Interest paid	$ 3,958	$ 4,064	$ 5,073
Income taxes paid	$ 8,629	$ 664	$ 3,970
Stock issue for services	$ 2	$ 59	$ 35

The accompanying notes are an integral part of these statements.

GEORESOURCES, INC. and SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2010, 2009 and 2008

NOTE A: Organization and Summary of Significant Accounting Policies

Merger

On April 17, 2007, pursuant to the terms of an Agreement and Plan of Merger ("Merger Agreement"), GeoResources, Inc. ("GeoResources" or the "Company"), a Colorado corporation, acquired Southern Bay Oil & Gas, L.P. ("Southern Bay"), a Texas limited partnership, PICA Energy, LLC ("PICA"), a Colorado limited liability company and subsidiary of Chandler Energy, LLC, and certain oil and gas properties in exchange for 10,690,000 shares of common stock (the "Merger"). These transactions resulted in a change in stockholder control of the Company. As a result of the Merger, the former Southern Bay partners received a majority of the outstanding common stock of the Company and thus, obtained voting control of the Company. Accordingly, for financial reporting purposes, the Merger was accounted for as a reverse acquisition of GeoResources and PICA by Southern Bay.

Organization and Basis of Presentation

GeoResources operates a single business segment involved in the acquisition, development and production of, and exploration for, crude oil, natural gas and related products primarily in Texas, North Dakota, Louisiana, Oklahoma, and Montana.

Summary of Significant Accounting Policies

Basis of Consolidation

The consolidated financial statements include the accounts of the Company and its majority-owned subsidiaries. The equity method is used to account for investments in affiliates in which the Company does not have majority ownership, but has the ability to exert significant influence. Intercompany accounts and transactions have been eliminated. The Company's investments in oil and gas limited partnerships for which it serves as general partner are accounted for under the equity method. The Company consolidates Trigon Energy Partners LLC ("Trigon") and records a noncontrolling interest, which represents the minority members' proportionate share of membership interests in Trigon. All other subsidiaries are wholly owned. Certain reclassifications were made to previously reported amounts in the consolidated financial statements and notes thereto to make them consistent with the current presentation format. Such reclassifications had no impact on net income, working capital, or total equity previously reported.

Cash and Cash Equivalents

Cash and cash equivalents consists of all demand deposits and funds invested in highly liquid investments with an original maturity of three months or less.

The Company maintains its cash and cash equivalents at financial institutions. The combined account balances at several institutions typically exceed Federal Deposit Insurance Corporation ("FDIC") insurance coverage and, as a result, there is a concentration of credit risk related to amounts on deposit in excess of FDIC insurance coverage. Management believes that this risk is not significant.

Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for oil and gas operations whereby cost to acquire mineral investments in oil and gas properties, to drill successful exploratory wells, to drill and equip development wells, and to install production facilities are capitalized. Exploration costs, including unsuccessful exploratory wells and geological and geophysical costs, are charged to operations as incurred. The Company's acquisition and development costs of proved oil and gas properties are amortized using the units-of-production method, at the field level, based on total proved reserves and proved developed reserves, respectively, as estimated by independent petroleum engineers.

Oil and gas properties are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flow expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to its estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets, generally on a field-by-field basis. The fair value of impaired assets is determined based on expected future cash flows using discount rates commensurate with the risks involved and using prices and costs consistent with those used for internal decision making. Long-lived assets committed by the Company for disposal are accounted for at the lower of cost or fair value, less cost to sell. The Company recognized impairments of $3.4 million, $2.8 million and $9.2 million for the years ended December 31, 2010, 2009 and 2008, respectively. Impairments recognized in 2010 and 2009 were on proved properties and are classified as impairments on the Company's income statement. During 2008, $855,000 of impairments resulted from the write-off of unproved properties during the second and fourth quarters of 2008 and is included in exploration expense on the Company's income statement. Also during 2008, the Company recognized $8.3 million of impairments on proved properties which are classified as impairments in the Company's income statement.

Office and Other Property

Acquisitions and improvements of office and other property are capitalized at cost; maintenance and repairs are expensed as incurred. Depreciation of equipment is calculated using the straight-line method over the assets estimated useful lives of 5-7 years. Leasehold improvements are amortized over the remaining term of the lease. When assets are sold, retired, or otherwise disposed of, the cost and related accumulated depreciation are eliminated from the accounts and a gain or loss is recognized.

Net Income Per Common Share

Basic net income per common share is computed based on the weighted average shares of common stock outstanding. Net income per share computations to reconcile basic and diluted net income for 2010, 2009 and 2008 consist of the following (in thousands, except per share data):

	Year ended December 31,		
	2010	**2009**	**2008**
Numerator:			
Net income available for common	$ 23,331	$ 9,775	$ 13,522
Denominator:			
Basic weighted average shares	19,721	16,532	15,598
Effect of dilutive securities - options	421	27	153
Diluted weighted average shares	20,142	16,559	15,751
Earning per share			
Basic	$ 1.18	$ 0.59	$ 0.87
Diluted	$ 1.16	$ 0.59	$ 0.86

Options to purchase 80,000, 726,505 and 25,000 shares were excluded from the diluted earnings per share calculation in 2010, 2009 and 2008, respectively, because the options' exercise prices exceeded the average market price of the common shares during the period.

Stock-Based Compensation

The Company recognizes in the financial statements all share-based payments made to employees, including grants of employee stock options, based on their fair values at the time of award.

Fair Value of Financial Instruments

The carrying amount of cash and cash equivalents, accounts receivable and payable and revenue royalties payable are estimated to approximate their fair values due to the short maturities of these instruments. The Company's long-term debt obligation bears interest at floating market rates, so carrying amounts and fair values are approximately equal. Derivative financial instruments are carried at fair value.

Income Taxes

Provision for income taxes is based on taxes payable or refundable for the current year and deferred taxes on differences between the tax bases of assets and liabilities and their reported amounts in the financial statements, which result from temporary differences between the amount of taxable income and pretax financial income. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. Tax positions are evaluated for recognition and measurement, with deferred tax balances recorded at their anticipated settlement amounts. A valuation allowance is provided for deferred tax assets not expected to be realized.

Other Comprehensive Income (Loss)

The Company reports comprehensive income on its Consolidated Statement of Equity and Comprehensive Income (Loss). Other comprehensive income (loss) at December 31, 2010, 2009 and 2008 consists of unrealized gains (losses) of derivatives qualifying as cash flow hedges in accordance with current accounting standards.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, 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. Oil and gas reserve estimates, which are the basis for units-of-production depreciation, depletion, and amortization are inherently imprecise and are expected to change as future information becomes available.

Derivative Instruments and Hedging Activities

The Company enters into derivative contracts, primarily options, collars and swaps, to hedge future crude oil and natural gas production, as well as interest rates, in order to mitigate the risk of downward movements of oil and gas market prices and the upward movement of interest rates. All derivatives are recognized on the balance sheet and measured at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in other comprehensive income to the extent the hedge is effective for cash flow hedges. To qualify for hedge accounting, the derivative must qualify either as a fair value, cash flow or foreign currency hedge.

The hedging relationship between the hedged instruments and hedged transactions must be highly effective in achieving the offset of changes in fair values and cash flows attributable to the hedged risk, both at the inception of the hedge and on an ongoing basis to qualify for hedge accounting. The Company measures hedge effectiveness on a quarterly basis. Hedge accounting is discontinued prospectively when a hedging instrument becomes ineffective. The Company assesses hedge effectiveness based on total changes in the fair value of options used in cash flow hedges rather than changes in intrinsic value only. As a result, changes in the entire value of option contracts are deferred in accumulated other comprehensive income until the hedged transaction affects earnings to the extent such contracts are effective. Gains and losses that were previously deferred in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered.

Gains and losses resulting from hedge settlements of commodity hedges are included in oil and gas revenues and are included in realized prices in the period that the related production is delivered. Gains and losses on hedging instruments that represent hedge ineffectiveness and gains and losses on derivative instruments that do not qualify for hedge accounting are included in other revenues or expenses in the period in which they occur. The resulting cash flows are reported as cash flows from operating activities.

Asset Retirement Obligations

The Company recognizes the present value of the estimated future abandonment costs of its oil and gas properties in both assets and liabilities. If a reasonable estimate of the fair value can be made, the Company will record a liability for legal obligations associated with the future retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of the assets. The fair value of a liability for an asset retirement obligation is recognized in the period in which the liability is incurred. The fair value is measured using expected future cash outflows (estimated using current prices that are escalated by an assumed inflation rate) discounted at the Company's credit-adjusted risk-free interest rate. The liability is then accreted each period until it is settled or the asset is sold, at which time the liability is reversed and any gain or loss resulting from the settlement of the obligation is recorded. The initial fair value of the asset retirement obligation is capitalized and subsequently depreciated or amortized as part of the carrying amount of the related asset.

The Company has recorded asset retirement obligations related to its oil and gas properties. There are no assets legally restricted for the purpose of settling asset retirement obligations.

Revenue Recognition

Revenues represent income from production and delivery of oil and gas, recorded net of royalties. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred, title has been transferred and if collectability of the revenue is probable. The Company follows the sales method of accounting for gas imbalances. A liability is recorded only if the Company's takes of gas volumes exceed its share of estimated recoverable reserves from the respective well or field. No receivables are recorded for those wells where the Company has taken less than its ownership share of production. Volumetric production is monitored to minimize imbalances, and such imbalances were not significant at December 31, 2010, 2009 or 2008.

Accounts Receivable

The Company sells crude oil and natural gas to various customers. In addition, the Company participates with other parties in the operation of crude oil and natural gas wells. Substantially all of the Company's accounts receivable are due from either purchasers of crude oil and natural gas or participants in crude oil and natural gas wells for which subsidiaries of the Company serve as the operator. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells. Crude oil and natural gas sales are generally unsecured.

As is common industry practice, the Company generally does not require collateral or other security as a condition of sale, rather relying on credit approval, balance limitation and monitoring procedures to control the credit use on accounts receivable. The allowance for doubtful accounts is an estimate of the losses in the Company's accounts receivable. The Company periodically reviews the accounts receivable from customers for any collectability issues. An allowance for doubtful accounts is established based on reviews of individual customer accounts, recent loss experience, current economic conditions, and other pertinent factors. Accounts deemed uncollectible are charged to the allowance. Provisions for bad debts and recoveries on accounts previously charged off are added to the allowance.

Accounts receivable allowance for bad debts was $369,000, $435,000, and $150,000 at December 31, 2010, 2009 and 2008, respectively.

Recently Issued Accounting Pronouncements

Each reporting period we consider all newly issued but not yet adopted accounting and reporting guidance applicable to our operations and the preparation of our consolidated financial statements. We do not believe that any issued accounting and reporting guidance we have not yet adopted will have a material impact on our consolidated financial statements.

NOTE B: Acquisitions

Bakken Acquisition

In May 2009, the Company closed an acquisition, through an existing joint venture partner, of producing wells and acreage in the Bakken shale trend of the Williston Basin. The Company acquired a 15% interest in approximately 60,000 net acres, and also acquired 15% of varying working interests in 59 producing and productive wells. The Company's net acquisition cost was approximately $10.4 million, subject to closing adjustments for normal operations activity and other customary purchase price adjustments. The Company funded the acquisition with borrowings from its senior secured revolving credit facility.

Giddings Field Acquisition

On May 29, 2009, effective May 1, 2009, the Company, through its subsidiary, Catena Oil and Gas LLC ("Catena"), entered into a Purchase and Sale Agreement (the "Purchase Agreement") with an affiliated limited partnership, SBE Partners LP (the "Seller") for the acquisition (the "Acquisition") of certain oil and gas producing properties in Giddings field, Grimes and Montgomery Counties, Texas (the "Interests"). Under the Purchase Agreement, the Interests were purchased for a cash purchase price of $48.7 million, net of closing adjustments for normal operations activity (the "Purchase Price"). In addition, the Company also acquired rights to certain post closing severance tax refunds which amounted to $2.4 million. The Acquisition increased the Company's partnership sharing ratio from 2% to 30% in the Seller. Catena is the general partner of the Seller. The Seller distributed to Catena $978,000 million of the gross proceeds from the sale. The Acquisition increased the Company's direct working interests in the Interests from a range of 6.5% to 7.8% to a range of 34% to 37%. The Company funded the Purchase Price with borrowings from its senior secured revolving credit facility. The Purchase Agreement contains representations and warranties, covenants, and indemnifications that are customary for oil and gas producing property acquisitions.

The following summary presents unaudited pro forma information for the years ended December 31, 2009 and 2008, as if the Acquisition had been consummated at January 1, 2008 (in thousands, except share and per share amounts):

	December 31, 2009	December 31, 2008
Total revenue	$ 93,536	$ 124,158
Income before taxes	21,491	38,227
Net income	13,718	24,001
Net income per share:		
Basic	$ 0.83	$ 1.54
Diluted	$ 0.83	$ 1.52
Weighted average shares:		
Basic	16,532,003	15,598,244
Diluted	16,559,431	15,751,185

Other

In November 2010, the Company purchased an 86.67% membership interest in Trigon Energy Partners LLC ("Trigon") in order to acquire and develop leases in the Eagle Ford shale trend of Texas. The acquisition cost was approximately $11.8 million. The Company fully consolidated Trigon and recorded a noncontrolling interest of $2.2 million for the year ended December 31, 2010. During 2010, Trigon did not generate any revenue or net income.

In May 2008, Southern Bay, through Catena, formed an entity in connection with the acquisition of producing oil and gas properties located throughout Oklahoma. OKLA Energy Partners LP ("OKLA") was formed with Catena as general partner with a 2% partnership interest, and a large institutional investor as the sole limited partner with a 98% partnership interest. These entities paid cash of $61.7 million to acquire these properties. Catena, purchased 18% of the interests and OKLA purchased the remaining 82%. Catena's share of the property purchase price was $12.8 million, and its general partner contribution to OKLA was $978,000. The Company's investment in OKLA is accounted for under the equity method of accounting.

In January 2008, the Company sold all of its interest in the Grand Canyon Unit, a property acquired in the Merger. This property, located in Otsego County, Michigan, was sold to an unaffiliated party for $6.6 million in cash. The carrying value of this property at the date of the sale was equal to the selling price; therefore, no gain or loss was recognized on sale.

In February 2008, the Company acquired producing properties in the Williston Basin of North Dakota and Montana from an unaffiliated party for $7.9 million in cash. The acquired properties are operated by the Company. The purchase price was allocated to oil and gas properties.

In February 2008, the Company sold its interests in certain non-core oil and gas properties located in Louisiana to unaffiliated parties for $1.8 million in cash and recognized gains of $430,000.

In May 2008, the Company closed certain property sales. These sales consisted of seven non-core fields in Louisiana and Texas and were sold to unaffiliated parties for approximately $11.8 million. The Company recognized a gain of $1.5 million related to these sales.

In September 2008, the Company acquired certain producing properties in Oklahoma from an unaffiliated party for $3.6 million in cash. The acquired properties are operated by the Company. The purchase price was allocated to oil and gas properties.

During 2008, the Company identified an exploration opportunity and began leasing in various counties in Colorado and Utah targeting the Gothic Shale as a newly emerging resource play with multiple other objectives. In November, 2008, the Company sold the majority of its interest for $6 million and recognized a gain of $2.5 million. The Company retained an overriding royalty interest or the option to participate, under certain circumstances, for up to 12.5% working interest.

In January 2009, the Company sold a producing property located in Louisiana to an unaffiliated party for $1.6 million. The Company recognized a gain of $1.3 million in conjunction with this sale.

On August 29, 2009, the Company, through its subsidiary, Catena, received a distribution of proved undeveloped property and unproved acreage in the Giddings field from SBE Partners LP ("SBE"), an affiliated partnership. The property was recorded at the estimated fair market value of $1.6 million, which exceeded its carrying value in the partnership. In conjunction with the distribution, SBE recorded a gain. The Company, which accounts for SBE as an equity method investment, included its share of the gain, $1.0 million, in the Company's partnership income during the third quarter 2009.

In October 2009, the Company initiated a leasing program in Williams County, North Dakota with the objective of establishing a significant operated position in the Bakken trend. In February 2010, the Company entered into agreements with two unaffiliated third parties to jointly develop the project. Cash proceeds to us totaled approximately $20 million and we retained a 47.5% working interest in the project area. The agreement also provided for up to $10 million ($4.75 million net) of additional joint leasing in a contractually specified area of mutual interest ("AMI"). As of December 31, 2010 our net acreage position in the project area totaled approximately 24,000 acres. For accounting purposes the Company uses the cost recovery method; under this method proceeds from joint owners have been recorded in the balance sheet as a reduction to the carrying value of the unproved properties. The Company's net investment in the prospect, after cost recoveries from its joint venture partners, as of December 31, 2010 was $2.5 million.

On July 30, 2010, the Company closed an acquisition of producing oil and gas properties located in the Giddings field of Central Texas. The purchase price was $16.6 million plus closing adjustments for normal operations activity. The acquisition holds approximately 9,700 acres and was funded through borrowings under the Company's credit facility. The amount of revenue and net income from the acquisition included in the Company's Consolidated Statement of Income for year ended December 31, 2010, was $2.7 million and $756,000, respectively.

In September 2010, the Company entered into an agreement with an unaffiliated third party to jointly acquire and develop mineral leases in the Eagle Ford shale trend of Texas. As part of this agreement, the Company sold a 50% working interest in approximately 20,000 acres for $20 million. For accounting purposes, the Company uses the cost recovery method; under this method proceeds from joint owners are recorded in the balance sheet as a reduction of the carrying value of unproved properties. The purchaser also agreed to pay the drilling costs for the first six wells to be drilled in a contractually specified AMI. The agreement also provides for an additional $20 million ($10 million net) for additional leasing within the AMI. Subsequent to the initial closing, the Company and the joint owners have continued to acquire leases within the AMI pursuant to the terms of the agreements. For the year ended December 31, 2010, the Company recognized a gain of $236,000 related to this transaction.

NOTE C: Long-term Debt

On October 16, 2007, the Company entered into an Amended and Restated Credit Agreement ("Amended Credit Agreement") with Wachovia Bank (the "Bank") as Administrative Agent, Issuing Bank, Sole Lead Arranger and Sole Bookrunner. The Amended Credit Agreement provided for financing of up to $200 million to the Company. The initial borrowing base of the Amended Credit Agreement was $110.0 million. On September 30, 2008, the borrowing base was reduced to $95 million. On November 5, 2008, the borrowing base was increased to $100 million and on April 6, 2009, the $100 million borrowing base was reaffirmed by the Bank.

On July 13, 2009, the Company entered into a Second Amended and Restated Credit Agreement ("Second Amended Credit Agreement"). The Second Amended Credit Agreement increased the facility from $200 million to $250 million and extended the term of the agreement to October 16, 2012. The initial borrowing base of the facility was $135 million, which was increased to $145 million in November 2009 and was $145 million as of December 31, 2010. The borrowing base is subject to redetermination on May 1 and November 1 of each year. The Second Amended Credit Agreement provides for interest rates at (a) LIBOR plus 2.25% to 3.00% or (b) the prime lending rate plus 1.25% to 2.00%, depending upon the amount borrowed. The Second Amended Credit Agreement also requires the payment of commitment fees to the lender in respect of the unutilized commitments. The commitment rate is 0.50% per annum. The Company is also required to pay customary letter of credit fees. All of the obligations under the Second Amended Credit Agreement, and the guarantees of those obligations, are secured by substantially all of the Company's assets.

The Second Amended Credit Agreement contains a number of covenants that, among other things, restrict, subject to certain exceptions, the Company's ability to incur additional indebtedness, create liens on assets, make investments, enter into sale and lease back transactions, pay dividends and distributions or repurchase its capital stock, engage in mergers or consolidations, make significant changes to management, sell certain assets, sell or discount any notes receivable or accounts receivable and engage in certain transactions with affiliates. In addition, the Second Amended Credit Agreement requires the maintenance of certain financial ratios, contains customary affirmative covenants, and provides for customary events of default. The Company was in compliance with all covenants at December 31, 2010.

The principal outstanding under the Second Amended Credit Agreement was $87 million and $69 million at December 31, 2010 and 2009, respectively. The annual interest rate in effect at December 31, 2010 was 2.77% on the entire amount of outstanding principal. The remaining borrowing capacity under the Second Amended Credit Agreement was $58 million as of December 31, 2010. The maturity date for amounts outstanding under the Seconded Amended Credit Agreement is October 16, 2012.

On January 20, 2011, the Company repaid the full outstanding balance of $87 million on the Second Amended Credit Agreement. The payment was funded using proceeds from the public offering of 5,175,000 shares of common stock completed on January 19, 2011.

Interest expense for 2010, 2009, and 2008 includes amortization of deferred financing costs of $1.1 million, $785,000, and $491,000, respectively. During 2010, the Company capitalized interest of $234,000. The Company did not capitalize any interest in 2009 or 2008.

In October 2007, the Company entered into an interest rate swap agreement with the Bank, providing a fixed rate of 4.79% on a notional $50 million through October 16, 2010. During 2008, the Company broke the swap up into two pieces, a $40 million swap and a $10 million swap each with a fixed annual interest rate of 4.29%. The $40 million swap was accounted for as a cash flow hedge while the $10 million swap was accounted for as a trading security. These swaps expired in October 2010. The fair market value of these swaps at December 31, 2009, was a liability of $1.6 million, all of which was classified as a current liability. During 2010, the Company recognized a net gain of $2,000 on the $10 million swap due to the cash settlement losses approximating the mark-to-market gain. The Company recognized a net loss of $162,000 on the $10 million swap during the year ended December 31, 2009. During the year ended December 31, 2008, the Company recognized a net loss of $563,000 on the $10 million swap.

At December 31, 2009, accumulated other comprehensive income included an unrecognized loss of $1.3 million, net of a tax benefit of $530,000. The unrecognized loss represents the inception to date change in mark-to-market value of the Company's $40 million interest rate swap, designated as a hedge, as of the balance sheet date. For the years ended December 31, 2010 and December 31, 2009, the Company recognized realized cash settlement losses of $1.3 million and $1.6 million, respectively, related to the $40 million swap. For the year ended December 31, 2008, the Company recognized realized cash settlement losses of $656,000 related to the $50 million swap which as discussed above was split into a $40 million and $10 million swap.

The weighted average interest rate on borrowings outstanding, inclusive of amortization of deferred financing costs and interest rate swaps, during 2010, 2009 and 2008 was 6.72%, 6.70% and 7.20%.

NOTE D: Stock Options, Performance Awards and Stock Warrants

In March 2007, the shareholders of the Company approved the GeoResources, Inc, Amended and Restated 2004 Employees' Stock Incentive Plan (the "Plan"), which authorizes the issuance of options and other stock-based incentives to officers, employees, directors and consultants of the Company to acquire up to 2,000,000 shares of the Company's common stock at prices which may not be less than the stock's fair market value on the date of grant. The options can be designated as either incentive options or nonqualified options.

On June 19, 2008, the Company granted options to employees to purchase 25,000 shares of common stock. These options have exercise prices ranging from $22.50 to $25.00 per share and have vesting dates ranging from June 19, 2010 to June 19, 2012. The closing market price of the Company's common stock on the date of the June 2008 grant was $20.99.

On February 3, 2009, and March 26, 2009, the Company granted options under the Plan to officers and other employees to purchase 300,000 and 225,000 shares of common stock, respectively. Also on February 3, 2009, the Company granted options to outside directors to purchase 200,000 shares of common stock. On October 20, 2009, the Company granted options to certain employees to purchase 25,000 shares of common stock. The closing market prices of the Company's common stock on the date of the February, March and October 2009 grants were $7.62, $7.16, and $12.70, respectively.

On April 7, 2010, the Company granted options under the Plan to an outside director to purchase 40,000 shares of common stock. Additionally, on June 1, 2010, the Company granted options under the Plan to purchase 35,000 shares of common stock to key employees. The following is a summary of the terms of these 2010 grants by exercise price:

	2010 Stock Option Grants						
Vesting Date	$13.79	$15.06	$15.75	$17.50	$17.75	$20.00	Total
Key Employees							
August 30, 2010	2,500	—	—	—	—	—	2,500
June 1, 2011	—	1,250	3,750	—	3,750	—	8,750
June 1, 2012	—	1,250	3,750	—	3,750	—	8,750
June 1, 2013	—	—	3,750	—	3,750	—	7,500
June 1, 2014	—	—	3,750	—	3,750	—	7,500
Director							
April 7, 2011	—	—	—	5,000	—	5,000	10,000
April 7, 2012	—	—	—	5,000	—	5,000	10,000
April 7, 2013	—	—	—	5,000	—	5,000	10,000
April 7, 2014	—	—	—	5,000	—	5,000	10,000
	2,500	2,500	15,000	20,000	15,000	20,000	75,000

The closing market prices of the Company's common stock on the dates of the April and June 2010 grants were: $17.27 and $13.69, respectively. The options, if not exercised, will expire 10 years from the date of grant.

A summary of the Company's stock option activity for the years ended December 31, 2010, 2009 and 2008 is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (year)	Weighted Average Fair Value	Aggregate Intrinsic Value
Outstanding, January 1, 2008	765,000	$ 8.92	9.78	$ 2.15	$ 275,575
Granted	25,000	$ 23.75		$ 6.82	
Exercised	—	$ —		—	
Forfeited	—	$ —		—	
Outstanding, December 31, 2008	790,000	$ 9.39	8.81	$ 2.29	$ 158,750
Granted	750,000	$ 9.42		$ 4.45	
Exercised	—	$ —		—	
Forfeited	—	$ —		—	
Outstanding, December 31, 2009	1,540,000	$ 9.40	8.30	$ 3.34	$ 6,827,275
Granted	75,000	$ 17.66		$ 8.52	
Exercised	(33,150)	$ 9.19		4.29	
Forfeited	(87,500)	$ 11.50		4.64	
Outstanding, December 31, 2010	1,494,350	$ 9.70	7.34	$ 3.49	$ 18,701,164

Exercisable at year-end	
2010	742,850
2009	382,500
2008	—

The weighted average grant date fair value of the options that vested during the year 2010 was $3.29 per option. The average intrinsic value for the 742,850 options exercisable as of December 31, 2010 is $9.7 million. These options have a weighted average exercise price of $9.11 and a weighted average remaining life of 6.93 years.

Unvested options at year-end:

	Number of Awards	Weighted Average Exercise Price	Weighted Average Fair Value
December 31, 2008	790,000	$ 9.39	$ 2.29
December 31, 2009	1,157,500	$ 9.77	$ 3.69
December 31, 2010	751,500	$ 10.28	$ 4.22

The Company recognized compensation expense based upon the fair value of the options at the date of grant determined by the Black-Scholes option pricing model. For the years ended December 31, 2010, 2009, and 2008, the Company recognized compensation expense of $1.1 million, $1.4 million, and $626,000 respectively, related to these options. As of December 31, 2010, the future pre-tax expense of non-vested stock options is $2.1 million ($1.3 million after taxes) to be recognized through the second quarter of 2014.

During 2010, 2009 and 2008 the weighted-average fair value of the options granted during the year was $8.52, $4.45, and $6.82 per share respectively, using the following assumptions:

	2010	2009	2008
Risk-free interest rate	2.03%	1.27%	2.25%
Dividend yield	None	None	None
Volatility	75%	86%	52%
Expected life of option	4 Years	4 Years	4 Years

In measuring compensation associated with these options, an annual pre-vesting forfeiture rate of 1% was used.

On June 5, 2008, we issued 613,336 warrants to purchase common stock to non-affiliated accredited investors pursuant to exemptions from registration under federal and state securities laws. The warrants have a term of five years ending June 5, 2013, with an exercise price $32.43 per share.

NOTE E: Income Taxes

The following table shows the components of the Company's income tax provision for 2010, 2009 and 2008:

	Year ended December 31,		
	2010	2009	2008
		(in thousands)	
Current:			
Federal	$ 8,111	$ 283	$ 695
State	750	129	171
Total current	8,861	412	866
Deferred			
Federal	2,570	4,318	6,186
State	492	337	717
Total deferred	3,062	4,655	6,903
Total	$ 11,923	$ 5,067	$ 7,769

The following is a reconciliation of taxes computed at the corporate federal statutory income tax rate of 35% to the reported income tax provision for the years ended December 31, 2010, 2009 and 2008:

	2010	2009	2008
		(in thousands)	
Income before income taxes	$ 35,254	$ 14,842	$ 21,291
Tax computed at federal statutory rate	$ 12,339	$ 5,195	$ 7,452
Statutory depletion in excess of tax basis	(1,060)	—	(562)
Domestic production activities deduction	(513)	—	(113)
State income taxes, net of federal benefit	876	521	716
Expense not deductible for tax purposes and other	281	(649)	276
Total income tax expense	$ 11,923	$ 5,067	$ 7,769
Effective tax rate	33.82%	34.14%	36.49%

Deferred income taxes are recognized for the tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and tax purposes, as required by current accounting standards. The deferred tax is measured using the enacted tax rates applicable to periods when these differences are expected to reverse.

The following table shows the components of the Company's net deferred tax liability at December 31, 2010, 2009 and 2008:

	2010	2009	2008
		(in thousands)	
Deferred tax asset or (liability)			
Current:	$ —	$ —	$ —
Noncurrent:			
Oil and gas properties	(24,536)	(20,178)	(15,334)
Other property and equipment	482	473	(101)
Equity in limited partnerships	(465)	(685)	(249)
Asset retirement obligations	2,652	1,703	2,066
Stock-based compensation	875	518	204
Commodity hedges and other	1,703	2,391	(4,454)
Net deferred tax liability	$ (19,289)	$ (15,778)	$ (17,868)

As of December 31, 2010, the Company had statutory depletion available for carryforward of approximately $3.1 million, which may be used to offset future taxable income. The amount that may be used in any year is subject to an annual limit of $1.1 million arising from a change in control resulting from the Merger.

Uncertain Tax Positionss

The Company will consider a tax position settled if the taxing authority has completed its examination, the Company does not plan to appeal, and it is remote that the taxing authority would reexamine the tax position in the future. The Company uses the benefit recognition model which contains a two-step approach, a more likely than not recognition criteria and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. The amount of interest expense recognized by the Company related to uncertain tax positions is computed by applying the applicable statutory rate of interest to the difference between the tax position recognized and the amount previously taken or expected to be taken in a tax return.

At December 31, 2010, the Company did not have any uncertain tax positions that would require recognition. The Company's uncertain tax positions may change in the next twelve months; however, the Company does not expect any possible change to have a significant impact on its results of operations or financial position.

The Company files a consolidated federal income tax return and various combined and separate filings in several state and local jurisdictions.

The Company's continuing practice is to recognize estimated interest and penalties, if any, related to potential underpayment of income taxes as a component of income tax expense in its Consolidated Statement of Income. As of December 31, 2010, the Company did not have any accrued interest or penalties associated with any uncertain tax liabilities.

The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statutes of limitations prior to December 31, 2011.

NOTE F: Derivative Financial Instruments

The Company enters into various crude oil and natural gas hedging contracts, primarily costless collars and swaps, in an effort to manage its exposure to product price volatility. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. Swaps are designed so that the Company receives or makes payments based on a differential between fixed and variable prices for crude oil and natural gas. The Company has designated its commodity derivative contracts as cash flow hedges designed to achieve more predictable cash flows, as well as to reduce its exposure to price volatility. While the use of derivative instruments limits the downside risk of adverse price movements, they also limit future revenues from favorable price movements. The Company does not enter into commodity derivative instruments for speculative or trading purposes.

At December 31, 2010 and 2009, accumulated other comprehensive income (loss) included unrecognized losses of $3.0 million and $2.5 million, respectively, net of taxes of $1.8 million and $1.7 million, respectively, representing the inception to date change in mark-to-market value of the effective portion of the Company's open commodity contracts, designated as cash flow hedges, as of the balance sheet date. For the years ended December 31, 2010 and 2009, the Company recognized realized cash settlement gains on commodity derivatives of $4.1 million and $7.4 million, respectively. For the year ended December 31, 2008, the Company recognized realized cash settlement losses on commodity derivative of $10.0 million. Based on the estimated fair market value of the Company's derivative contracts designated as hedges at December 31, 2010, the Company expects to reclassify net losses of $3.2 million into earnings from accumulated other comprehensive income (loss) during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially.

On October 17, 2008, the Company paid $3.0 million to cancel its 2009 natural gas swaps that were previously accounted for as cash flow hedges. At the time of cancelation, accumulated other comprehensive (loss) contained $482,000 of acquisition to date change in mark-to-market of the effective portion of these commodity derivative contracts. These accumulated losses were amortized during 2009 and reduce net income by $482,000.

During the first quarter of 2010, the Company entered into one new crude oil swap contract. The contract has a term of February 2010 to December 2011 and provides for 10,000 Bbls per month during 2010 and 7,000 Bbls per month during 2011. The swap has fixed prices for 2010 and 2011 of $85.32 and $88.45, respectively.

During the third quarter of 2010, the Company entered into an additional crude oil swap contract. The contract has a term of September 2010 to December 2012 and provides for 10,000 Bbls per month. The swap has a fixed price of $85.05 from September 2010 to December 2011 and a fixed price of $86.85 during 2012.

During the fourth quarter of 2010, the Company entered into a crude oil swap contract. The contract has a term of January 2011 to December 2012 and provides for 5,000 Bbls per month during 2011 and 10,000 Bbls per month during 2012. The swap has a fixed price of $85.16 during 2011 and $87.22 during 2012.

Subsequent to year-end, the Company entered into one additional natural gas swap contract and two crude oil collars. The natural gas swap has a term of January 2012 to March 2013 and provides for 75,000 MMBTUs per month. The swap has a fixed price of $4.85 per MMBTU. The first crude oil collar has a term of February 2011 through December 2011 and provides 5,000 Bbls per month. The floor price is $85.00 and the ceiling price is $106.08. The second crude oil collar has a term of January 2012 through December 2012 and provides 10,000 Bbls per month. The floor price is $85.00 and the ceiling price is $110.00.

At December 31, 2010, the Company had hedged its exposure to the variability in future cash flows from forecasted oil and gas production volumes as follows:

	Total Remaining Volume	Floor Price	Ceiling / Swap Price
Crude Oil Contracts (Bbls):			
Swap contracts:			
2011	282,000		$ 74.370
2011	84,000		$ 88.450
2011	120,000		$ 85.050
2011	60,000		$ 85.160
2012	120,000		$ 87.220
2012	120,000		$ 86.850
Natural Gas Contracts (Mmbtu)			
Swap contracts:			
2011	210,000		$ 6.065
2011	630,000		$ 6.450
2012	150,000		$ 6.450
2012	450,000		$ 6.415
Costless collar contracts:			
2011	1,079,000	$ 7.000	$ 9.200

The fair market value of our gas hedge contracts in place at December 31, 2010 and 2009, were assets of $5.1 million and $2.1 million, respectively, of which $4.3 million and $764,000 were classified as current assets, respectively. The fair market value of our oil hedge contracts in place at December 31, 2010 and 2009 were liabilities of $9.1 million and $6.4 million, respectively, of which $7.4 million and $3.2 million were classified as current liabilities, respectively. For the year ended December 31, 2010 and 2009, we recognized, in oil and gas revenues, realized cash settlement gains on commodity derivatives of $4.1 million and $7.4 million, respectively. During 2010 and 2008, we recognized gains due to hedge ineffectiveness of $891,000 and $123,000, respectively. Due to hedge ineffectiveness on hedge contracts during 2009 we recognized a loss of $137,000.

To reduce the impact of changes in interest rates on our variable rate term loan, we entered into a two-year interest rate swap contract on $50 million of the debt, designed to protect against interest rate increases. During 2008, the Company extended the term of this interest rate swap through October, 2010, and broke the swap up into two pieces, a $40 million swap and a $10 million swap. The Company accounted for the $40 million swap as a cash flow hedge while the $10 million swap was accounted for as a trading security. The interest rate swaps are further discussed in Note C above.

All derivative instruments are recorded on the consolidated balance sheet of the Company at fair value. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands):

Derivatives designated as ASC 815 hedges:	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	Dec. 31, 2010	Dec. 31, 2009	Balance Sheet Location	Dec. 31, 2010	Dec. 31, 2009
Commodity contracts	Current derivative financial instruments asset	$ 4,282	$ 764	Current derivative financial instruments liability	$ (7,433)	$ (3,167)
Commodity contracts	Long-term derivative financial instruments asset	851	1,360	Long-term derivative financial instruments liability	(1,650)	(3,233)
Interest rate swap contract	Current derivative financial instruments asset	—	—	Current derivative financial instruments liability	—	(1,302)
Interest rate swap contract	Long-term derivative financial instruments asset	—	—	Long-term derivative financial instruments liability	—	—
		$ 5,133	$ 2,124		$ (9,083)	$ (7,702)

Derivatives not designated as ASC 815 hedges:	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	Dec. 31, 2010	Dec. 31, 2009	Balance Sheet Location	Dec. 31, 2010	Dec. 31, 2009
Interest rate swap contract	Current derivative financial instruments asset	$ —	$ —	Current derivative financial instruments liability	$ —	$ (325)
Interest rate swap contract	Long-term derivative financial instruments asset	—	—	Long-term derivative financial instruments liability	—	—
		$ —	$ —		$ —	$ (325)

Derivative contracts – The following tables summarize the effects of commodity and interest rate derivative instruments on the consolidated statements of income for the years ended December 31, 2010, 2009 and 2008 (in thousands):

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Recognized in OCI on Derivative (Effective Portion)		
	2010	2009	2008
Commodity contracts	$ 3,512	$ (10,834)	$ 22,511
Interest rate swap contracts	—	(646)	(2,055)
	$ 3,512	$ (11,480)	$ 20,456

Derivatives designated as ASC 815 hedges:	Amount of Gain or (Loss) Reclassified from OCI into Income (Effective Portion)			Location of Gain or (Loss) Reclassifed from OCI into Income (Effective Portion)
	2010	2009	2008	
Commodity contracts	$ 4,078	$ 7,434	$ (9,970)	Oil and gas revenues
Interest rate swap contracts	(1,294)	(1,598)	(656)	Interest expense
	$ 2,784	$ 5,836	$ (10,626)	

Derivatives in ASC 815 cash flow hedging relationships:	Location of (Gain) or Loss Recognized in Income on Derivative (Ineffective Portion)	Amount of (Gain) or Loss Recognized in Income on Derivative (Ineffective Portion) 2010	2009	2008
Commodity contracts	Hedge ineffectivenss	$ (891)	$ 137	$ (123)

Derivative not designated as ASC 815 hedges:	Location of (Gain) or Loss Recognized in Income on Derivative	Amount of (Gain) or Loss Recognized in Income on Derivative 2010	2009	2008
Realized cash settlements on interest rate swap	(Gain) loss on derivative contracts	$ 323	$ 399	$ —
Unrealized (gain) loss on interest rate swap	(Gain) loss on derivative contracts	(325)	(237)	563
		$ (2)	$ 162	$ 563

Contingent features in derivative instruments – None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's derivative contracts, in the opinion of the Company, are high credit quality financial institutions.

NOTE G: Fair Value Disclosures

ASC Topic 820 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

ASC Topic 820 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 – inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of the input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers between Level 1 and Level 2 of the fair value hierarchy during the years ended December 31, 2010 or 2009. Further, there were no transfers in and/or out of Level 3 of the fair value hierarchy during the years ended December 31, 2010 and 2009.

Cash, Cash Equivalents, Accounts Receivable and Payable and Revenue Royalties – The carrying amount of cash and cash equivalents, accounts receivable and payable and royalties payable are estimated to approximate their fair values due to the short maturities of these instruments.

Long-term Debt – The Company's long-term debt obligation bears interest at floating market rates, so carrying amounts and fair values are approximately equal.

Derivative Financial Instruments – Derivative financial instruments are carried at fair value. Commodity derivative instruments consist of costless collars and swaps for crude oil and natural gas. The Company's costless collars are valued based on the counterparty's marked-to-market statements, which are validated by observable transactions for the same or similar commodity options using the NYMEX futures index, and are designated as Level 2 within the valuation hierarchy. The Company's swaps are valued based on a discounted future cash flow model. The primary input for the model is the NYMEX futures index. The Company's model is validated by the counterparty's marked-to-market statements. The swaps are also designated as Level 2 within the valuation hierarchy. The discount rate used in determining the fair values of these instruments includes a measure of nonperformance risk. The Company's interest rate swaps are valued using the counterparty's marked-to-market statement, which can be validated using modeling techniques that include market inputs such as publicly available interest rate yield curves, and is designated as Level 2 within the valuation hierarchy.

The tables below present information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2010 and 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value.

Derivative Assets and Liabilities - December 31, 2010
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2010
Current portion of derivative financial instrument asset [1]	—	$ 4,282	—	$ 4,282
Long-term portion of derivative financial instrument asset [1]	—	851	—	851
Current portion of derivative financial instrument liability [1]	—	(7,433)	—	(7,433)
Long-term portion of derivative financial instrument liability [1]	—	(1,650)	—	(1,650)

(1) Commodity derivative instruments accounted for as cash flow hedges.

Derivative Assets and Liabilities - December 31, 2009
(in thousands)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Current portion of derivative financial instrument asset [1]	—	$ 764	—	$ 764
Long-term portion of derivative financial instrument asset [1]	—	1,360	—	1,360
Current portion of derivative financial instrument liability [2]	—	(4,794)	—	(4,794)
Long-term portion of derivative financial instrument liability [1]	—	(3,233)	—	(3,233)

(1) Commodity derivative instruments accounted for as cash flow hedges.
(2) Includes a $40 million interest rate swap accounted for as a cash flow hedge ($1,302,000) and a $10 million interest rate swap accounted for as a trading security ($325,000) and a commodity derivative accounted for as a cash flow hedge ($3,167,000).

At December 31, 2010 and 2009, the Company did not have any assets or liabilities measured at fair value on a recurring basis that meet the definition of Level 1 or Level 3.

Asset Impairments – The Company reviews proved oil and gas properties for impairment at least annually and when events and circumstances indicate a significant decline in the recoverability of the carrying value of such properties. When events and circumstances indicate a significant decline in the recoverability of a property, the Company estimates the future cash flows expected in connection with the property and compares such future cash flows to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying amount of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include significant Level 3 assumptions associated with estimates of future oil and gas production, commodity prices based on commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate.

The Company recorded asset impairments of $3.4 million and $2.8 million on proved properties during the years ended December 31, 2010 and 2009, respectively. During the year ended December 31, 2008, the Company recorded impairments of $855,000 on unproved properties and $8.3 on proved properties. All of the 2010, 2009 and 2008 impairments on proved properties were included in impairment expense while the 2008 impairments on unproved properties, due to the nature of the expenses, were included in exploration expense. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include the Company's estimate of future natural gas and crude oil prices, operating and development costs, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

Asset Retirement Obligations – The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of the Company's asset retirement obligation is presented in Note H.

Property Acquisitions and Business Combinations – The Company records the identifiable assets acquired, liabilities assumed and any non-controlling interests at fair value at the date of acquisition. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and gas production, commodity prices based on commodity futures price strips as of the date of the estimate, operating and development costs, and a risk-adjusted discount rate. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the determination of fair value of the acquisition include the Company's estimate of future natural gas and crude oil prices, operating and development costs, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. The Company's acquisitions are discussed in Note B.

NOTE H: Asset Retirement Obligations

The Company's asset retirement obligations represent the estimated future costs associated with the plugging and abandonment of oil and gas wells, and removal of equipment and facilities from leased acreage and land restoration, in accordance with applicable local, state and federal laws. The Company determines its obligation by calculating the present value of estimated cash flows related to plugging and abandonment obligations. The changes to the Asset Retirement Obligations ("ARO") for oil and gas properties and related equipment during the years ended December 31, 2010 and 2009 are as follows (in thousands):

	Year ended December 31	
	2010	2009
Balance, beginning of year	$ 6,110	$ 5,418
Additional liabilities incurred	314	262
Accretion Expense	405	368
Disposals of properties	(105)	(188)
Revisions of estimates	328	250
Balance, end of year	$ 7,052	$ 6,110

NOTE I: Concentration of Credit Risk

Credit risk represents the accounting loss which the Company would record if its customers failed to perform pursuant to the contractual terms. The Company's largest customers are large companies. In addition, the Company transacts business with independent oil producers, crude oil trading companies and a variety of other entities. The Company's credit policy and the relatively short duration of receivables mitigate the risk of uncollected receivables.

In 2010, two purchasers each accounted for 12% of the Company's consolidated oil and gas revenues and one purchaser accounted for 11%. In 2009, one purchaser accounted for 17% of the Company's consolidated oil and gas revenues, two purchasers accounted for 15% each, and one more accounted for 11%. In 2008, one purchaser accounted for 16% of the Company's consolidated oil and gas revenue, two others accounted for 11% each and two purchasers accounted for 10% each. No other single purchaser accounted for 10% or more of the Company's consolidated oil and gas revenues in 2010, 2009, or 2008. There are adequate alternate purchasers of production such that the loss of one or more of the above purchasers would not have a material adverse effect on the Company's results of operations or cash flows.

NOTE J: Commitments and Contingencies

Commitments

The Company is obligated under non-cancelable operating leases for its office facilities as follow (in thousands):

2011	$ 329
2012	340
2013	348
2014	357
2015	197
Thereafter	10
	$ 1,581

Total rental expense under operating leases for 2010, 2009 and 2008 was $369,000, $374,000, and $324,000, respectively.

Contingencies

No significant legal proceedings are pending which are expected to have a material adverse effect on the Company. The Company is unaware of any potential claims or lawsuits involving environmental, operating or corporate matters which are expected to have a material adverse effect on the Company's financial position or results of operations.

NOTE K: Related Party Transactions

Accounts receivable at December 31, 2010 and 2009 include $753,000 and $785,000, respectively, due from SBE Partners LP ("SBE Partners"). Accounts receivable at December 31, 2010 and 2009, also includes $219,000 and $148,000, respectively, due from OKLA Energy Partners LP ("OKLA Energy"). Both of these partnerships are oil and gas limited partnerships for which a subsidiary of the Company serves as general partner. These amounts represent the limited partnerships' share of property operating expenditures incurred by operating subsidiaries of the Company on their behalf, as well as accrued management fees. Accounts payable at December 31, 2010 and 2009, includes $2.3 million and $7.6 million, respectively, due to SBE Partners for oil and gas revenues and severance tax refunds collected on its behalf. Accounts payable at December 31, 2010 and 2009, also includes $654,000 and $778,000, respectively due to OKLA Energy for oil and gas revenues collected on its behalf.

The Company earned partnership management fees during the years ended December 31, 2010, 2009, and 2008 of $550,000, $1.0 million and $1.7 million, respectively.

Subsidiaries of the Company operate the majority of oil and gas properties in which the two limited partnerships have an interest. Under this arrangement, the Company collects revenues from purchasers and incurs property operating and development expenditures on each partnership's behalf. These revenues are paid monthly to each partnership, which in turn reimburses the Company for the partnership's share of expenditures.

In May 2009, the Company, through its subsidiary, Catena, entered into a Purchase and Sale Agreement with an affiliated limited partnership, SBE Partners. Catena purchased the properties for $49.3 million. As the General Partner of SBE Partners, Catena received a distribution from the partnership as a result of the sale of $987,000. The net purchase price for the properties was $48.4 million. This acquisition is discussed in Note B above.

NOTE L: Equity Investments

The Company accounts for its investment in SBE Partners L.P. and OKLA Energy using the equity method of accounting. Under this accounting method the Company records its share of income and expenses. Contributions to the investment increase the Company's investment while distributions from the partnership decrease the Company's carrying value of the investment.

OKLA Energy, formed during 2008, holds direct working interests in producing oil and gas properties located throughout Oklahoma. GeoResources' 2% general partner interest reverts to 35.66% when the limited partner realizes a contractually specified rate of return. The Company recorded a loss in partnership income related to this investment for the years ended December 31, 2010 and 2009 of $39,000 and $34,000, respectively. For the year ended December 31, 2008 the Company recorded income of $16,000.

SBE Partners, formed during 2007, holds direct working interests in producing oil and gas properties located in Giddings field in Texas. Previously, GeoResources held a 2% general partner interest which increased after reaching a cumulative payout. As result of the sale of certain properties and subsequent distribution of proceeds by the Partnership cumulative payout was achieved and the Company's general partner interest increased to 30%. For further information about the sale see Note B above. For the years ended December 31, 2010, 2009 and 2008 the Company recorded partnership income of $2.3 million, $4.4 million, and $1.0 million, respectively.

The Company's carrying value for its equity investment in OKLA Energy at December 31, 2010 and 2009 was $709,000 and $846,000, respectively. The Company's carrying value for its equity investment in SBE Partners at December 31, 2010 and 2009 was $1.6 million and $2.7 million, respectively. During 2010, the Company received cash distributions of $3.4 million and $100,000 from SBE Partners and OKLA Energy, respectively.

The following is a summary of selected financial information of SBE Partners, LP as of and for the years ended December 31, 2010, 2009 and 2008 (in thousands):

	2010	2009	2008
Summary of Partnership selected balance sheet information:			
Current assets	$ 5,831	$ 11,933	$ 23,009
Oil and gas properties, net	$ 59,745	$ 60,834	$ 98,757
Total assets	$ 68,993	$ 73,686	$ 123,686
Current liabilities	$ 1,032	$ 1,047	$ 2,348
Total liabilities	$ 2,161	$ 1,876	$ 3,343
Partner's capital	$ 66,832	$ 71,810	$ 120,343
Summary of Partnership operations:			
Revenues	$ 19,181	$ 52,429	$ 82,721
Income from continuing operations	$ 6,419	$ 29,726	$ 51,060
Net income	$ 6,419	$ 29,726	$ 51,060
The Company's equity in partnership net income	$ 2,279	$ 4,352	$ 1,045
The Company's capital balance in the partnership	$ 1,565	$ 2,686	$ 2,273

NOTE M: Supplemental Financial Quarterly Results (Unaudited):

The sum of the individual quarterly basic and diluted earnings (loss) per share amounts may not agree with year-to-date basic and diluted earnings (loss) per share amounts as a result of each period's computation being based on the weighted average number of common shares outstanding during that period.

	Three Months Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
	(in thousands, except per share data)			
Year ended December 31, 2010				
Oil and gas revenues	$ 24,729	$ 24,343	$ 25,612	$ 25,229
Other revenues (1)	1,549	1,021	1,294	1,744
Operating expenses (2)	(13,875)	(13,089)	(13,914)	(14,152)
Operating income	12,403	12,275	12,992	12,821
Other income (expense), net (3)	(2,552)	(4,947)	(2,735)	(5,003)
Income tax (expense) benefit	(3,777)	(2,885)	(2,621)	(2,640)
Net income	$ 6,074	$ 4,443	$ 7,636	$ 5,178
Basic net income per share	$ 0.31	$ 0.23	$ 0.39	$ 0.26
Diluted net income per share	$ 0.30	$ 0.22	$ 0.38	$ 0.26

	Three Months Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
	(in thousands, except per share data)			
Year ended December 31, 2009				
Oil and gas revenues	$ 12,300	$ 16,829	$ 19,980	$ 22,509
Other revenues (1)	2,160	2,398	2,980	852
Operating expenses (2)	(10,713)	(10,912)	(13,286)	(14,668)
Operating income	3,747	8,315	9,674	8,693
Other income (expense), net (3)	(2,910)	(2,600)	(3,706)	(6,371)
Income tax (expense) benefit	(360)	(2,216)	(2,540)	49
Net income (loss)	$ 477	$ 3,499	$ 3,428	$ 2,371
Basic net income (loss) per share	$ 0.03	$ 0.22	$ 0.21	$ 0.14
Diluted net income (loss) per share	$ 0.03	$ 0.22	$ 0.21	$ 0.14

(1) Partnership management fees, property operating income, gain (loss) on sale of property and partnership income.

(2) Lease operating expense, production taxes, re-engineering and workover, exploration, and depreciation depletion and amortization and general administrative expense.

(3) Other income (expense), net for the second and fourth quarters of 2010 included impairment expenses of $2.7 million and $697,000, respectively. For the second and fourth quarters 2009, Other income (expense), net included impairment expense of $128,000 and $2.7 million, respectively.

NOTE N: Supplemental Financial Information for Oil and Gas Producing Activities (Unaudited)

1. Costs Incurred Related to Oil and Gas Activities

The Company's oil and gas activities for 2010, 2009 and 2008 were entirely within the United States. Costs incurred in oil and gas producing activities were as follows:

	Year Ended December 31, 2010	2009	2008
		(in thousands)	
Acquisition cost:			
Proved	$ 18,739	$ 59,686	$ 29,123
Unproved	$ 22,880	$ 6,908	$ 4,823
Exploration cost:			
Exploratory drilling	$ 5,225	83	2,431
Geological and geophsical	$ 630	1,323	161
Development cost	$ 35,349	$ 23,623	$ 16,974

Unproved acquisition costs for 2010 is net of cost recoveries of $40.2 million received from the sale of interests in undeveloped properties from third parties. As of December 31, 2010, we capitalized $5.2 million of exploratory well costs that are pending the determination of proved reserves. The Company did not capitalize any exploratory well costs in 2009 or 2008. During 2010, 2009 and 2008, additions to oil and gas properties of $314,000, $262,000 and $158,000 were recorded for estimated costs of future abandonment related to new wells drilled or acquired.

	December 31, 2010	2009
	(in thousands)	
Proved properties	$ 341,582	$ 285,363
Unproved properties	32,403	10,281
	373,985	295,644
Accumulated depreciation, depletion and amortization	(71,805)	(47,731)
Net capitalized cost	$ 302,180	$ 247,913

The amounts included in unproved properties are projects for which the Company intends to commence exploration or evaluation projects in the near future. The Company will begin to amortize these costs when proved reserves are established or an impairment is determined.

2. Estimated Quantities of Proved Oil and Gas Reserves

For all years presented, the estimate of proved reserves and related valuations were based on reports prepared by the Company's independent petroleum engineers. The reports were prepared by Cawley, Gillespie & Associates, Inc. Proved reserve estimates included herein conform to the definitions prescribed by the U.S. Securities and Exchange Commission. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under economic and operating conditions existing as of the end of each respective year. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods.

Presented below is a summary of the changes in estimated proved reserves of the Company, all of which are located in the United States, for the years ended December 31, 2010, 2009 and 2008:

Oil and Gas Reserve Quantities:

	Oil (MBbl)	Gas (MMcf)
Proved reserve quantities, December 31, 2007	10,744	29,810
Purchase of minerals-in-place	672	9,726
Sales of minerals-in-place	(988)	(4,946)
Extensions and discoveries	501	1,155
Production	(743)	(2,962)
Revisions of quantity estimates	(1,393)	2,013
Proved reserve quantities, December 31, 2008	8,793	34,796
Purchase of minerals-in-place	586	25,728
Sales of minerals-in-place	(59)	(80)
Extensions and discoveries	972	9,227
Production	(851)	(4,944)
Revisions of quantity estimates	1,978	(9,291)
Proved reserve quantities, December 31, 2009	11,419	55,436
Purchase of minerals-in-place	531	1,388
Extensions and discoveries	1,553	1,390
Production	(1,060)	(4,789)
Revisions of quantity estimates	1,950	4,129
Proved reserve quantities, December 31, 2010	14,393	57,554
Proved developed reserve quantities:		
December 31, 2008	7,522	25,025
December 31, 2009	9,221	38,138
December 31, 2010	11,231	39,097
Proved undeveloped reserve quantities:		
December 31, 2008	1,271	9,771
December 31, 2009	2,198	17,298
December 31, 2010	3,162	18,457

Notable changes in proved reserves for the year ended December 31, 2010 and 2009 included:

In 2009, the revision increase in estimated oil quantities related to price increases was 2,204,000 Bbls, which was partially offset by reductions of 1,030,000 Bbls due to a change in pricing method as prescribed by the SEC. Other increases of 804,000 Bbls accounted for the remainder of the total positive revision of 1,978,000 Bbls. The revision decrease in estimated gas quantities related to price increases was 960,000 Mcf, offset by a decrease of 10,572,000 Mcf attributable to the change in pricing methods prescribed by the SEC. Other increases in gas reserves of 321,000 Mcf accounted for the remainder of the negative revision of 9,291,000 Mcf. The change in pricing method prescribed by the SEC is from the use of a year-end price to the use of a 12-month average price, which is discussed in Note A, Recently Issued Accounting Pronouncements.

In 2010, the revision increase in estimated oil quantities related to price increases was approximately 1,024,000 Bbls as SEC prescribed oil prices increased from the December 31, 2009 price of $61.18 per Bbl to the December 31, 2010 price of $79.43 per Bbl. Net positive performance revisions of approximately 926,000 Bbls accounted for the remainder of the total positive revision of 1,950,000 Bbls. The revision increase in estimated gas quantities related to the price increases was approximately 6,032,000 Mcf as SEC prescribed gas prices increased from December 31, 2009 of $3.83 per Mmbtu to the December 31, 2010 price of $4.37 per Mmbtu. Net negative performance revisions of approximately 1,903,000 Mcf accounted for the remainder of the total positive revisions of 4,129,000 Mcf. In 2010, the majority of the 1,553,000 Bbls and 1,390,000 Mcf of proved reserves added through extensions and discoveries are a direct result of our successful Bakken drilling activities in North Dakota and eastern Montana.

3. Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with FASB ASC topic *Extractive Activities – Oil and Gas*. Future cash inflows as of December 31, 2010 and 2009, were computed by applying average fiscal-year prices (calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period ended December 31, 2010 and 2009, respectively) to estimated future production. Future cash inflows as of December 31, 2008, however, were computed by applying prices at year-end to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year-end, based on year-end costs and assuming the continuation of existing economic conditions.

Future income tax expense is calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves, less the tax basis of the properties involved. Future income tax expense gives effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily result in an estimate of the fair value of the Company's oil and gas properties.

Presented below is the standardized measure of discounted future net cash flows as of December 31, 2010, 2009 and 2008.

Standardized Measure of Estimated Future Net Cash Flows

	December 31,		
	2010	2009	2008
		(in thousands)	
Future cash inflows	$ 1,266,679	$ 789,647	$ 547,966
Future production costs	455,685	316,815	228,369
Future development costs	90,814	64,560	35,020
Future income taxes	188,887	83,182	56,860
Future net cash flows	531,293	325,090	227,717
10% annual discount for estimated timing of cash flows	254,278	150,990	107,098
Standardized measure of discounted future cash flows	$ 277,015	$ 174,100	$ 120,619

Future cash flows as shown above are reported without consideration for the effects of open hedge contracts at each period end. If the effects of hedging transaction were included in the computation, undiscounted future cash flows would have decreased by $4.0 million in 2010, decreased by $4.3 million in 2009, and increased by $14.6 million in 2008.

The principal sources of changes in the standardized measure of discounted future net cash flows for 2010, 2009 and 2008 are as follows:

Changes in Standardized Measure

	Year Ended December 31,		
	2010	2009 *	2008
	(in thousands, except product prices)		
Standardized measure, beginning of period	$ 174,100	$ 120,619	$ 278,646
Changes in prices, net of production cost	111,342	47,246	(206,127)
Extensions, discoveries and enhanced production	36,111	20,989	6,571
Revision of quantity estimates	42,413	14,876	(4,221)
Development costs incurred, previously estimated	5,613	7,045	876
Change in estimated future development costs	(7,972)	(17,629)	9,676
Purchases of minerals-in-place	16,161	36,002	17,401
Sales of minerals-in-place	—	(786)	(39,923)
Sale of oil and gas produced, net of production costs	(66,341)	(53,860)	(61,283)
Accretion of discount	23,268	16,663	43,861
Change in estimated future income taxes	(57,792)	(13,495)	73,348
Changes in timing of estimated cash flows and other	112	(3,570)	1,794
	$ 277,015	$ 174,100	$ 120,619
Prices, used in standardized measure:			
Oil (per barrel)	$ 79.43	$ 61.18	$ 41.47
Gas (per Mcf)	$ 4.37	$ 3.83	$ 5.29

* In 2009, standardized measure was reduced by $90.0 million due to the use of a 12-month average price as prescribed by the new reserve rules (discussed in Note A Recently Issued Accounting Pronouncements) versus an end of the year price. Had the Company not changed its pricing method to comply with the SEC's new rules the standardized measure at December 31, 2009 would have been $264.1 million.

Equity in Partnership Reserves

1. Costs Incurred Related to Oil and Gas Activities

The following two unaudited tables set forth the Company's share of costs incurred in the affiliated partnerships during the years ended December 31, 2010, 2009, and 2008. During 2009, the Company's interest in one of the partnerships, SBE Partners, increased significantly from 2% to 30%. For further information see note L above.

Costs incurred in acquisition, development and exploration:

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Acquisition cost	$ 250	$ 346	$ 949
Development cost	$ 304	$ 771	$ 633
Exploration cost	$ 7	$ —	$ —

Capitalized cost of oil and gas properties:

	December 31,	
	2010	2009
	(in thousands)	
Proved properties	$ 3,997	$ 3,610
Unproved properties	—	—
	3,997	3,610
Accumulated depreciation, depletion and amortization	(811)	(746)
Net capitalized cost	$ 3,186	$ 2,864

2. Estimated Quantities of Proved Oil and Gas Reserves and Discounted Future Net Cash Flows

The reserve information presented above does not include the Company's share of reserves held by two limited partnerships which are accounted for under the equity method of accounting. The following table presents the Company's estimated share of the oil and gas reserves held by both limited partnerships as of December 31, 2010, 2009 and 2008.

	Year Ended December 31,					
	2010		2009		2008	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Oil and gas volumes:						
Proved developed	45	6,993	45	7,821	58	12,227
Proved undeveloped	7	861	10	613	61	4,510
Total	52	7,854	55	8,434	119	16,737

Presented below is a summary of the changes in estimated proved reserves of the Company's equity investments, all of which are located in the United States, for the year ended December 31, 2010:

Oil and Gas Reserve Quantities:

	Oil (MBbl)	Gas (MMcf)
Proved reserve quantities, January 1, 2010	55	8,434
Production	(5)	(1,007)
Revision of quantity estimates	2	427
Proved reserve quantities, December 31, 2010	52	7,854
Proved developed reserve quantities:		
December 31, 2010	45	6,993
Proved undeveloped reserve quantities:		
December 31, 2010	7	861

Presented below is the Company's share of standardized measure of discounted future net cash flows as of December 31, 2010 for its equity investments:

Standardized Measure of Estimated Future Net Cash Flows (in thousands):

Future cash inflows	$ 33,916
Future production costs	11,485
Future development costs	2,506
Future income taxes	6,512
Future net cash flows	13,413
10% annual discount for estimated timing of cash flows	5,345
Standardized measure of discounted future cash flows	$ 8,068

The principal sources of change in the Company's share of standardized measure of discounted future net cash flows for the Company's equity investments for 2010 are as follows (in thousands except for product prices):

Changes in Standardized Measure

Standardized measure, beginning of period	$	7,335
Changes in prices, net of production cost		3,525
Revision of quantity estimates		454
Development costs incurred, previously estimated		824
Change in estimated future development costs		(867)
Sale of oil and gas produced, net of production costs		(3,000)
Accretion of discount		910
Change in estimated future income taxes		(643)
Changes in timing of estimated cash flows and other		(470)
	$	8,068
Current prices at year-end, used in standardized measure:		
Oil (per barrel)	$	79.43
Gas (per Mcf)	$	4.37

NOTE O: Subsequent Events

On January 19, 2011, we issued 5,175,000 shares of common stock and 989,000 shares were sold by certain selling shareholders in a public offering, at a price of $25.00 per share. The Company's net proceeds from the offering were approximately $122.9 million after deducting the underwriters' discount and other offering expenses, and were used to pay off our outstanding indebtedness under our Second Amended Credit Agreement of $87 million. The remaining net proceeds will primarily be used to fund drilling and development expenditures.

Signatures

Pursuant to the requirements of Section 13 of the Securities Exchange Act of 1934, the Registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GEORESOURCES, INC. (the "Registrant")

Dated: March 11, 2011

/s/ Frank A. Lodzinski

Frank A. Lodzinski, 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.

(Power of Attorney)

Each person whose signature below constitutes and appoints FRANK A. LODZINSKI and HOWARD E. EHLER his true and lawful attorneys-in-fact and agents, each acting along, with full power of stead, in any and all capacities, to sign any or all amendments to this annual report on Form 10-K for the year ended December 31, 2010, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, each acting alone, full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in each acting alone, or his substitute or substitutes, may lawfully do or cause to be done by virtue thereof.

Signature	Title	Date
/s/ Frank A. Lodzinski Frank A. Lodzinski	President, Chief Executive Officer (principal executive officer) and Director	March 11, 2011
/s/ Howard E. Ehler Howard E. Ehler	Principal Financial Officer and Principal Accounting Officer	March 11, 2011
/s/ Collis P. Chandler, III Collis P. Chandler, III	Director	March 11, 2011
/s/ Bryant W. Seaman, III Bryant W. Seaman, III	Director	March 11, 2011
/s/ Jay F. Joliat Jay F. Joliat	Director	March 11, 2011
/s/ Donald J. Whelley Donald J. Whelley	Director	March 11, 2011
/s/ Nicholas L. Voller Nicholas L. Voller	Director	March 11, 2011
/s/ Michael A. Vlasic Michael A. Vlasic	Director	March 11, 2011

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 11, 2011, with respect to the consolidated financial statements and internal control over financial reporting included in the Annual Report of GeoResources, Inc. on Form 10-K for the year ended December 31, 2010. We hereby consent to the incorporation by reference of said reports in the Registration Statements of GeoResources, Inc. on Forms S-3 (File No. 333-144831, effective August 13, 2007; File No. 333-152041, effective July 10, 2008; File No. 333-155681, effective February 5, 2009 and File No. 333-170832, effective December 9, 2010) and on Forms S-8 (File No. 333-145221, effective August 8, 2007 and File No. 333-149216, effective February 13, 2008).

/s/ Grant Thornton LLP
Houston, Texas
March 11, 2011

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 11, 2011,with respect to the financial statements of SBE Partners LP included in the Annual Report of GeoResources, Inc. on Form 10-K for the year ended December 31, 2010. We hereby consent to the incorporation by reference of said report in the Registration Statements of GeoResources, Inc. on Forms S-3 (File No. 333-144831, effective August 13, 2007; File No. 333-152041, effective July 10, 2008; File No. 333-155681, effective February 5, 2009 and File No. 333-170832, effective December 9, 2010) and on Forms S-8 (File No. 333-145221, effective August 8, 2007 and File No. 333-149216, effective February 13, 2008).

/s/ Grant Thornton LLP
Houston, Texas
March 11, 2011

Exhibit 23.3

Cawley, Gillespie & Associates, Inc.
PETROLEUM CONSULTANTS

1000 LOUISIANA STREET, SUITE 625
HOUSTON, TEXAS 77002-5008
713-651-9944
FAX 713-651-9980

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817-336-2461
FAX 817-877-3728

9601 AMBERGLEN BLVD., SUITE 117
AUSTIN, TEXAS 78729-1106
512-249-7000
FAX 512-233-2618

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of GeoResources, Inc. for the year ended December 31, 2010. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from GeoResources, Inc.'s oil and gas reserves as of December 31, 2010, 2009 and 2008 and to the inclusion of our report dated February 25, 2011 as an exhibit to the Annual Report on Form 10-K of GeoResources, Inc. for the year ended December 31, 2010. We further consent to the incorporation by reference thereof into GeoResources, Inc.'s Registration Statements on Forms S-3 (File No. 333-144831, effective August 13, 2007; File No. 333-152041, effective June 30, 2008; File No. 333-155681, effective November 25, 2008; and File No. 333-170832, effective December 19, 2010) and on Forms S-8 (File No. 333-145221, effective August 8, 2007 and File No. 333-149216, effective February 13, 2008).

Sincerely,

Cawley, Gillespie & Assoc., Inc.

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

March 9, 2011

EXHIBIT 31.1

CERTIFICATION

I, Frank A. Lodzinski, certify that:

1. I have reviewed this Annual Report on Form 10-K of GeoResources, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Frank A. Lodzinski

Frank A. Lodzinski
Chief Executive Officer
March 11, 2011

EXHIBIT 31.2

CERTIFICATION

I, Howard E. Ehler, certify that:

1. I have reviewed this Annual Report on Form 10-K of GeoResources, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Howard E. Ehler

Howard E. Ehler
Chief Financial Officer
March 11, 2011

EXHIBIT 32.1

CERTIFICATION

I, Frank A. Lodzinski, certify that:

In connection with the Annual Report on Form 10-K of GeoResources, Inc. (the "**Company**") for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "**Report**"), I, Frank A. Lodzinski, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Frank A. Lodzinski

Frank A. Lodzinski
Chief Executive Officer
March 11, 2011

* The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

EXHIBIT 32.2

CERTIFICATION

I, Howard E. Ehler, certify that:

In connection with the Annual Report on Form 10-K of GeoResources, Inc. (the "**Company**") for the year ended December 31, 2010, as filed with the Securities and Exchange Commission on the date hereof (the "**Report**"), I, Howard E. Ehler, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley of 2002, that:

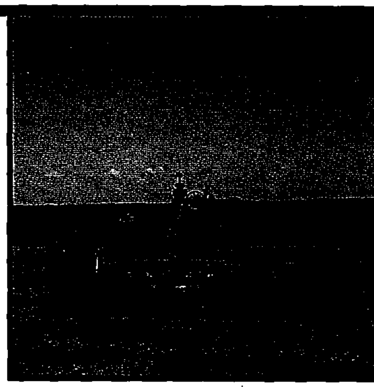
1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Howard E. Ehler

Howard E. Ehler
Chief Financial Officer
March 11, 2011

* The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

Shareholder Information



Officers & Directors

Frank A. Lodzinski
President, Chief Executive Officer & Chairman

Robert J. Anderson
EVP, Engineering & Acquisitions

Collis P. Chandler, III
EVP, Chief Operating Officer - Northern Region & Director

Howard E. Ehler
VP, Chief Financial Officer

Francis M. Mury
EVP, Chief Operating Officer - Southern Region

Independent Directors

Jay F. Joliat
Joliat Enterprises, LLC

Bryant W. Seaman, III
Bessemer Trust

Michael A. Vlasic
Vlasic Investments, LLC

Nicholas L. Voller
Voller, Lee & Suess, P.C., CPAs

Donald J. Whelley
DJW Advisors, LLC

Investor Relations

Financial analysts, investors and shareholders desiring information about GeoResources, Inc. should write to Cathy Kruse, Investor Relations, P. O. Box 1505, Williston, ND 58802 or call 701-572-2020. Information may also be obtained by visiting the company's website.

Auditors

Grant Thornton LLP

Independent Reservoir Engineers

Cawley, Gillespie & Associates, Inc.

Legal Counsel

Jones & Keller

Website

www.georesourcesinc.com

Corporate and Regional Offices

GeoResources, Inc.
110 Cypress Station Dr., Suite 220
Houston, TX 77090-1629
Tel: 281-537-9920
Fax: 281-537-8324

Southern Region
Southern Bay Energy, LLC
110 Cypress Station Dr., Suite 220
Houston, TX 77090-1629
Tel: 281-537-9920
Fax: 281-537-8324

Northern Region
G3 Energy, LLC
475 17th St., Suite 1210
Denver, CO 80202
Tel: 303-297-2028
Fax: 303-297-2196

Williston Basin
G3 Operating, LLC
1407 W. Dakota Pky., Suite 1
Williston, ND 58801
Tel: 701-572-2020
Fax: 701-572-0277

Transfer Agent

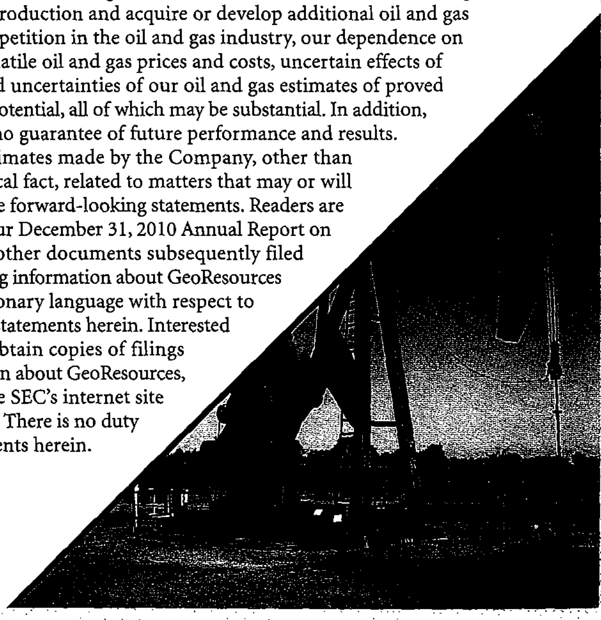
Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
Tel: 800-468-9716
website: www.wellsfargo.com/shareownerservices

Stock Traded

GeoResources, Inc. common stock trades on the NASDAQ Global Market under the ticker GEOI.

Forward-Looking Information

Forward Looking Statements - Information included herein contains forward-looking statements that involve significant risks and uncertainties, including our need to replace production and acquire or develop additional oil and gas reserves, intense competition in the oil and gas industry, our dependence on our management, volatile oil and gas prices and costs, uncertain effects of hedging activities and uncertainties of our oil and gas estimates of proved reserves and reserve potential, all of which may be substantial. In addition, past performance is no guarantee of future performance and results. All statements or estimates made by the Company, other than statements of historical fact, related to matters that may or will occur in the future are forward-looking statements. Readers are encouraged to read our December 31, 2010 Annual Report on Form 10-K and our other documents subsequently filed with the SEC regarding information about GeoResources for meaningful cautionary language with respect to the forward-looking statements herein. Interested persons are able to obtain copies of filings containing information about GeoResources, without charge, at the SEC's internet site (http://www.sec.gov). There is no duty to update the statements herein.



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NASDAQ: GEOI