GEOI INC.

2005 Annual Report

ABOUT GEORESOURCES, INC.

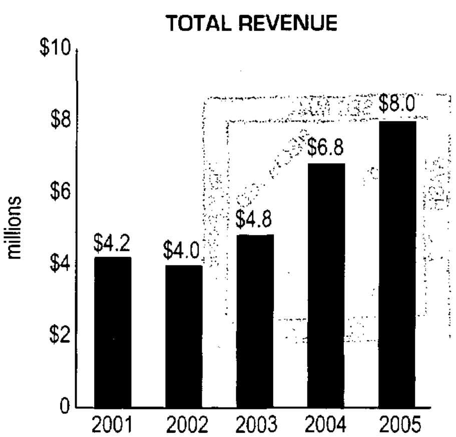
GeoResources, Inc. is a natural resources company engaged in three principal business segments – oil and gas exploration, development and production; oil and gas drilling; and leonardite mining and the manufacture of leonardite-based products. GeoResources, Inc. is traded on the Nasdaq SmallCap Market under the symbol "GEOI."

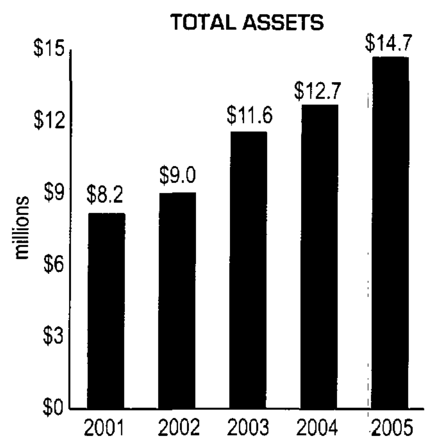
GeoResources has a substantial oil and gas exploration and production operation in the Williston Basin. This business segment historically constitutes more than 70 percent of GeoResources' revenue and earnings. In 2005, the Company produced an average of 331 net equivalent barrels of oil per day from 138 productive wells located within 50 fields in North Dakota and Montana. At December 31, 2005, GeoResources owned proved reserves of 3 million barrels of oil equivalent with an SEC value of $44 million. Ninety-two percent of those reserves are crude oil.

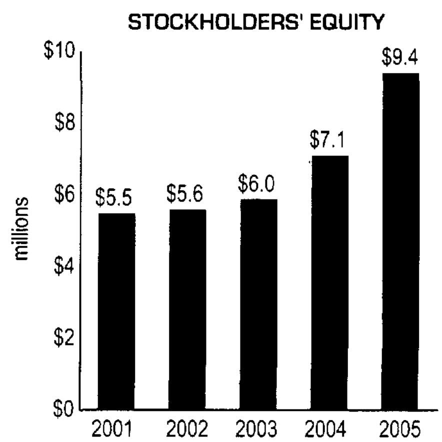
In late 2001, GeoResources formed a subsidiary company, Western Star Drilling Company, to acquire and operate a drilling rig for its own use and for contract drilling operations. Western Star Drilling's Rig E-25 is deployed in the Williston Basin in the north central region of North Dakota. Given the competitive market for drilling rigs, GeoResources' ownership of Western Star Drilling is a critical component that will enable the Company to execute its development plans, while generating cash flow from third-party drilling operations.

In addition to its oil and gas activities, the Company operates a leonardite mine and processing plant at Williston, North Dakota. At the Williston facility, a distinctive type of oxidized lignite coal called leonardite is mined from leased reserves and processed into several different specialty products. Those products include drilling mud additives for use in the oil and natural gas drilling industry and applications in metal working factories and in agriculture.

INDEX







THE YEAR AT A GLANCE

(highlights in $000s except per share and production data)	**2005**	2004	2003	2002	2001
For the Year					
Oil and Gas Revenue	**$ 5,824**	$ 4,452	$ 3,615	$ 2,980	$ 3,064
Leonardite Revenue	**811**	1,291	822	727	1,152
Drilling Revenue	**1,360**	1,077	406	281	–
Total Revenue	**$ 7,995**	$ 6,820	$ 4,843	$ 3,988	$ 4,216
Net Income (Loss)	**$ 2,179**	$ 1,106	$ 447	$ 91	$ 42
Per Share, basic	**$ .58**	$ .30	$ .12	$ .02	$ .01
At Year-End					
Working Capital (Deficit)	**$ 978**	$ 85	$ (173)	$ 311	$ (224)
Total Assets	**$ 14,700**	$ 12,720	$ 11,584	$ 9,048	$ 8,202
Long-Term Debt	**$ 178**	$ 1,206	$ 1,599	$ 1,910	$ 1,035
Current Maturities	**$ 524**	$ 519	$ 479	$ 132	$ 125
Stockholders' Equity	**$ 9,356**	$ 7,080	$ 5,974	$ 5,616	$ 5,536
Production Statistics					
Productive Wells (gross)	**138**	142	141	139	134
Oil (Bbls)	**119,450**	122,939	135,865	140,468	149,916
Gas (Mcf)	**7,586**	5,351	8,234	10,374	11,496
Barrels of oil equivalent (BOE)	**120,714**	123,831	137,237	142,197	151,832
BOE per day	**331**	338	376	390	416
Leonardite (tons)	**5,667**	10,093	6,558	6,511	9,779
Proved Reserves At-Year End					
Proved Developed Producing					
Oil (MBbls)	**1,826**	1,576	1,605	1,548	1,316
Gas (MMcf)	**270**	51	44	70	71
Proved Developed Non-Producing					
Oil (MBbls)	**244**	76	30	34	14
Gas (MMcf)	**1,126**	340	343	351	279
Proved Undeveloped					
Oil (MBbls)	**742**	690	823	905	767
Total Proved Reserves					
Oil (MBbls)	**2,812**	2,342	2,458	2,487	2,097
Gas (MMcf)	**1,396**	391	387	421	350
MBoe	**3,045**	2,407	2,523	2,557	2,155
% Proved Developed	**76%**	71%	67%	65%	64%
Future Cash Flow from Proved Reserves	**$ 89,375**	$ 46,316	$ 37,925	$ 34,978	$ 11,715
Present Value at 10%, before Income Taxes	**$ 43,669**	$ 27,018	$ 21,444	$ 19,814	$ 6,687
Standardized Measure	**$ 30,756**	$ 19,276	$ 15,567	$ 14,458	$ 5,480

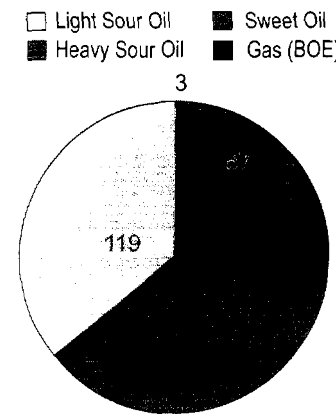
LETTER TO SHAREHOLDERS

If I were only allowed two words to describe the fluctuating price of oil over the last 25 years, it would be more VALUE. In the almost 30 years I have been working in the energy industry, I have seen the rise and fall of crude oil numerous times. Unlike the cycles of the 80's and 90's, this decade has brought an unprecedented rise in crude oil and natural gas "prices" and increased investor confidence about the future of all energy-related industries.

Worldwide oil and gas values were the single most important aspect of our operating performance and financial results during 2005. Our average price for crude oil in 2005 was $48.25, a record for the company. This resulted in total operating revenue of $8 million, a 17% increase over 2004. When commodity prices rise, so do prices for equipment and services; however, rising production costs are not a new challenge for us. We increased net income 97% to $2.2 million or $.58 per share in 2005 versus $1.1 million or $.30 per share in 2004.

The bulk of this increase occurred in our exploration and production business segment where we reported $3.0 million of operating income before SG&A on $5.8 million of revenue in 2005 versus $1.9 million of operating income on $4.5 million of revenue in 2004. Our proved reserves increased 27% to 3.0 million BOE in 2005 from 2.4 million BOE in 2004. We believe now is the time to grow our production through the use of the drill bit, and we plan to pursue an active drilling program in 2006.

AVERAGE DAILY PRODUCTION (BOE)



For the last few years, we have been focused on growing our land-drilling business, which is owned and operated by our subsidiary, Western Star Drilling Company. Western Star increased drilling days and footage 9% and 42%, respectively in 2005, signifying that demand for our drilling services is growing in the Williston Basin. Third-party revenue increased 26% to $1.4 million while we reported an operating loss before SG&A of $50,233. Although we reported a small operating loss, we are excited about the potential of this segment. Owning Western Star adds value to our Company by ensuring rig access for GeoResources' oil and gas drilling projects.

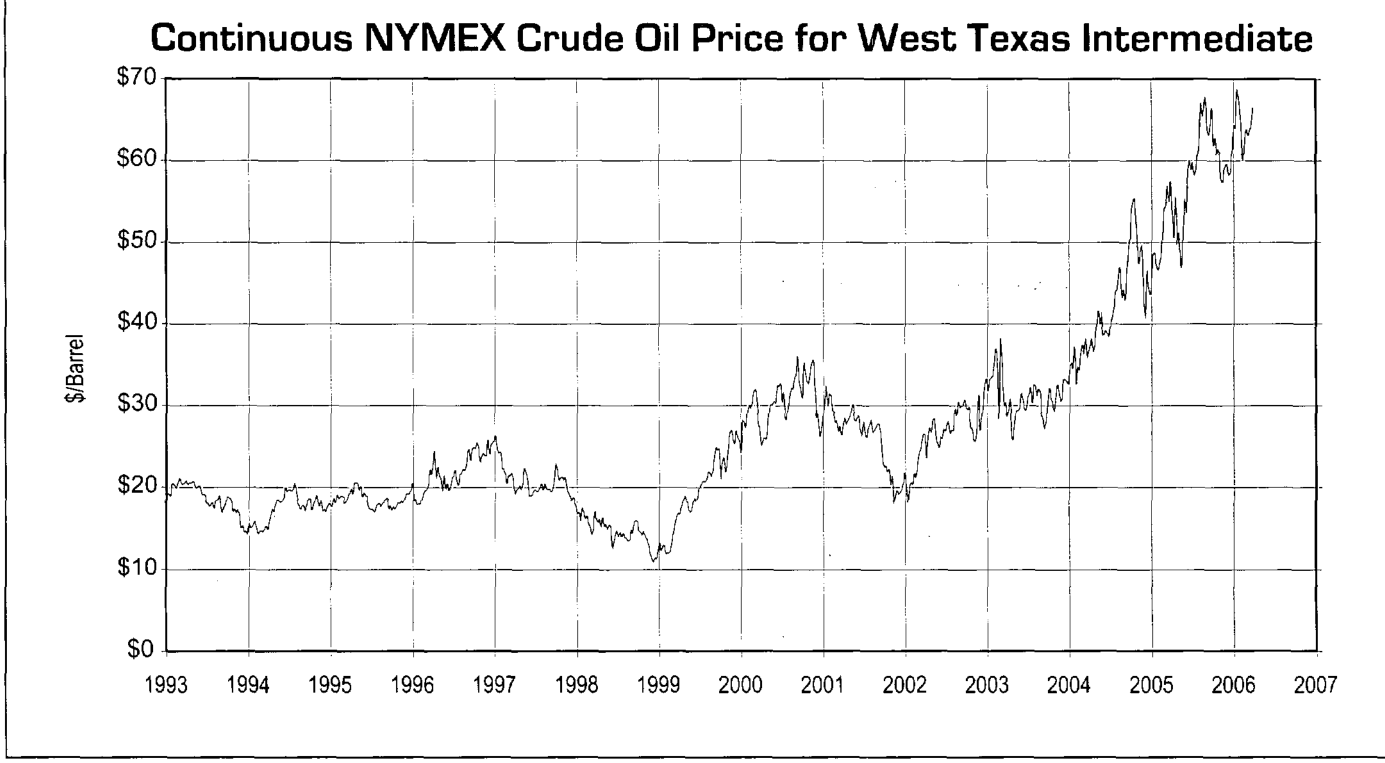
OPERATING DATA - RIG E-25

	2005	2004
Total Operating Days	**162**	148
Total Operating Footage	**56,987**	40,270
Outside Operating Revenue	**$1,359,872**	$1,077,367

When GeoResources went public in 1971, the foundation for our business was manufacturing a drilling mud additive. In that business segment we operated a leonardite mine and processing plant at Williston, North Dakota until May 2005. Regrettably, in May production was halted due to damage sustained by a fire. Insurance proceeds are available to cover replacement costs, but it is our goal to also modernize the facility if restoration is the path we take. In the meantime, we are exploring markets for our leonardite raw material.

	Productive Wells*				Producing Wells				Service Wells	
	Oil		Gas		Oil		Gas			
Year	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2005	**113**	**88.22**	**25**	**25.00**	**105**	**80.54**	**0**	**0.00**	**16**	**13.80**
2004	117	89.09	25	25.00	108	83.20	0	0.00	14	11.93
2003	115	87.62	26	25.25	103	78.10	0	0.00	14	11.93
2002	113	85.57	26	25.25	107	79.07	0	0.00	14	11.93
2001	108	80.13	26	25.25	108	80.14	0	0.00	15	12.41

*Producing wells and non-producing wells deemed capable of production.



As I write this letter there is much public debate about the price of energy, the vulnerability of energy supplies and the need for conservation. In the media we are bombarded with suspicions that big, bad major oil companies are responsible for fixing the "price" of oil – HOGWASH! The price of crude oil and natural gas is determined by factors beyond the control of any one company, group of companies or countries. I believe that we, as a nation, must begin thinking in terms of the VALUE of energy to our way of life, not the "price". The value of energy will drive conservation and development of a multitude of alternative energy sources including coal, electricity, nuclear, wind, solar, geothermal, ethanol, bio-diesel, biomass and those yet to be perfected or discovered. The mature energy industries and the alternatives in their infancy all need the same thing – a sustained price of oil and gas that recognizes the value of the resource and encourages development of domestic supplies and alternatives to fossil fuels. The low oil prices during the last 20 years have been the problem NOT the solution. We trust ingenuity and entrepreneurship will develop well-rounded, environmentally responsible energy solutions as long as the price of oil reflects its true value to society. GeoResources welcomes and supports alternative energy industries, even though we are invested primarily in oil and gas. We look forward to the company and our shareholders being a tiny piece of America's energy industry for the future.

On behalf of the Board of Directors, management and GeoResources' employees, thank you for your interest: past, present, and future.

Sincerely,

J. P. (Jeff) Vickers,
President
April 21, 2006

EXPLORATION & DEVELOPMENT

GeoResources, Inc. (GEOI) engages in the exploration, production and development of oil and gas in the Williston Basin primarily in the north central portion of North Dakota. The primary objective of this segment is to develop our oil and gas reserves, find new reserves, and achieve a rate of return from our inventory of projects.

At December 2005, GEOI had leasehold and other interests in 138 gross productive wells (113.22 net) located in 50 fields in North Dakota and Montana. In order to maximize the efficiency of our assets, we maintain a high working interest and operate 81% of the wells. The Company manages its operations from our headquarters in Williston, North Dakota and our field offices in Westhope, North Dakota and Alzada, Montana.

During 2005, the Company drilled two wells, a development well in the Leonard Field and an exploratory well in our Kramer prospect, both of which are located in Bottineau County, North Dakota. The development well was drilled and completed in line with original expectations; however, the exploratory well attempting to discover a new field, was a dry hole.

Oil and gas production sold in 2005 was 120,714 BOE, a slight 2% drop compared to the prior year; however, we believe our Leonard Field that began production in January 2006 will add meaningful production this year. Additional drilling is planned for 2006. We have one drilling permit in progress and have targeted to drill a total of three operated wells in Bottineau County, setting the stage for more production growth. Another large project we are committed to in 2006 is returning the Hammond Field of Carter County, Montana to gas production, and the substantive increase of non-producing gas reserves in the year at a glance table reflects that commitment. In general, estimated reserve quantities increased in virtually every category due largely to higher oil and gas prices that extend the life of low decline properties. Our future plans remain focused on increasing production and controlling operating costs.

DRILLING

In 2005, our subsidiary company, Western Star Drilling Company (WSDC) drilled two wells for GeoResources, Inc. and eight for other operators. As WSDC grows, the optimum utilization of the rig is drilling approximately 20 wells per year of the type and depth that are typical in the shallower portions of the Williston Basin. The scope of business for WSDC is to be utilized to drill wells in the United States portion of the Williston Basin, typically North Dakota and Montana.

Owning our own drilling company ensures the timing of GEOI projects. In late 2001 we purchased and retrofitted Rig E-25 because we were unable to secure a rig in a timely manner. Rig E-25 is a conventional "little double" designed for shallow drilling to a maximum vertical depth of 8,000 feet, horizontal drilling to similar true vertical depths and under-balanced horizontal drilling. WSDC is committed to health, safety and environmental compliance.

LEONARDITE

In 2005, we secured a new mining permit and mine plan from the North Dakota Public Service Commission and the Bureau of Land Management (BLM). Our Leonardite mining operation is in a 240-acre Logical Mining Unit that contains 160 acres of BLM leasehold. A new pit opened on the new permit area in January 2006. The mine site is approximately one mile from our processing plant. Leonardite is hauled to our plant site and stockpiled until processing.

In May 2005, the processing plant sustained damage due to a fire, and production was suspended which resulted in a production and revenue decline for the year. The actual processing equipment was not damaged, but the damage to the electrical systems that control the operation of the equipment was significant. Insurance proceeds are expected to cover the replacement cost value. Although Leonardite operations have not been a substantial portion of our cash flow or profit in recent years, the fire was still very disappointing.

Restoration tactics and timing are being investigated. Modernizing the drying process is just one of numerous considerations we need to bear in mind prior to restoration. In the meantime, we are pursuing a market for our Leonardite raw material and keeping all of our options open to make the best use of our assets.

U. S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-KSB

(Mark One)

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended **December 31, 2005**.

Commission File Number – 0-8041

GeoResources, Inc.

(Exact name of Registrant as specified in its charter)

Colorado (State or other jurisdiction of incorporation or organization)	84-0505444 (I.R.S. Employer Identification No.)
1407 West Dakota Parkway, Suite 1-B Williston, North Dakota (Address of Principal executive offices)	58801 (Zip Code)
(Issuer's telephone number including area code)	(701) 572-2020

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

Securities registered pursuant to Section 12 (g) of the Act: Common Stock, par value $0.01

Check whether the Issuer is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. [ ]

Check whether the Issuer (1) filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the past 12 months (or for such shorter period that the Issuer was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B is not contained in this form, and no disclosure will be contained, to the best of registrant's knowledge in definitive proxy or information statements incorporated by reference in Part III of this Form 10-KSB or any amendment to this Form 10-KSB. [X]

Indicate by checkmark whether the registrant is a shell company (as defined in rule 12b-2 of the Exchange Act. Yes [ ] No [X]

Issuer's revenues for its most recent fiscal year. $7,994,659

At March 15, 2006, the aggregate market value of the voting stock held by non-affiliates of the registrant was approximately $37,495,451.

As of March 15, 2006, registrant had 3,767,269 shares of its common stock outstanding.

PART I.

ITEM 1. DESCRIPTION OF BUSINESS

General Development of Business

GeoResources, Inc. is a natural resources company engaged in three principal business segments: a) oil and gas exploration, development and production; b) oil and gas drilling; and c) mining of leonardite (oxidized lignite coal) and manufacturing of leonardite based products, which are sold primarily as oil and gas drilling mud additives. We were incorporated under Colorado law in 1958 and were originally engaged in uranium mining. We built our first leonardite processing plant in 1964 in Williston, North Dakota, and began participating in oil and gas exploration and production in 1969. In 1982, we completed construction of a larger leonardite processing plant in Williston, which was in operation until it sustained damage from a fire on May 17, 2005. The facility was insured to replacement cost value, and we have notified the insurance company that we plan to restore the facility for operations. No one was injured in the fire. See Item 2 and Note N to the Consolidated Financial Statements. We purchased our oil and gas drilling rig in 2001 and formed a subsidiary for drilling operations in 2002. Financial information about our three operating segments is presented in Note B to the Financial Statements in Item 7 of this report.

Information contained in this Form 10-KSB contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by the use of words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or variations of these words or comparable terminology. In addition, all statements other than statements of historical facts that address activities, events or developments that we expect, believe or anticipate will or may occur in the future, and other such matters, are forward-looking statements.

Our future results may vary materially from those anticipated by management and may be affected by various trends and factors, which are beyond our control. Please review some of the more significant risks we face under the heading "Risk Factors" presented at the end of this item.

Oil and Gas Exploration, Development and Production

Our oil and gas exploration and production efforts are concentrated on oil properties in the North Dakota and Montana portions of the Williston Basin. We typically generate prospects for our own exploitation, but when we believe a prospect may have substantial risk or cost, we may attempt to raise all or a portion of the funds necessary for exploration or development through farmouts, joint ventures, or other similar types of cost-sharing arrangements. The amount of interest retained by us in a cost-sharing arrangement varies widely and depends upon many factors, including the exploratory costs and the risks involved.

In addition to originating our own prospects, we occasionally participate in exploratory and development prospects originated by other individuals and companies. We also evaluate interests in various proved properties to acquire for further operation and/or development.

As of December 31, 2005, we had developed oil and gas leases covering approximately 16,019 net acres in Montana and North Dakota, and during 2005 sold an average 331 net equivalent barrels of oil and gas per day from 138 gross (113 net) productive wells located primarily in North Dakota.

We sell our crude oil and natural gas to purchasers with facilities located near our wells.

Oil and Gas Drilling

Our subsidiary, Western Star Drilling Company (WSDC), owns and operates a drilling rig, which is capable of drilling to 8,000 feet. The rig consists of engines, drawworks, a mast, pumps, blowout preventers, a drillstring, and related equipment. From time to time, the rig will be used to drill our prospects; however, WSDC will also contract with other entities to drill their wells. We believe that the ownership of WSDC facilitates the development of our leasehold acreage while providing an additional revenue stream through contract drilling.

WSDC provides the rig, equipment and personnel on a contract basis. The drilling contracts are obtained through competitive bidding or as a result of negotiations with customers. To date, all of the drilling contracts have been performed on a "daywork" basis, under which a fixed rate is charged per day, with the price determined by the location, depth, and complexity of the well to be drilled, operating conditions and the competitive forces of the market. In most instances, contracts provide for additional payments for mobilization and demobilization of the rig.

Mining and Manufacturing of Leonardite Products

We operate a leonardite mine and processing plant in Williston, North Dakota. Leonardite is mined from leased reserves and is sold as a raw material or is processed to make a basic or blended specialty product. Our manufacturing facility sustained damage from a fire on May 17, 2005, and the majority of the damage was to the electrical systems that control the operation of the plant to process and bag the basic and blended leonardite specialty products. We have notified our insurance company that we plan to restore our plant, but the timing for that restoration is not known at this time due to possible processing changes we are investigating. See Item 2 and Note N to the Consolidated Financial Statements.

Historically, our leonardite products were sold primarily to drilling mud companies located in coastal areas of the Gulf of Mexico. Leonardite products act as a dispersant or thinner and provide filtration control when used as an additive in drilling muds. Leonardite is also sold by us for use in metal working foundries and in agricultural applications. Demand for our plant's output is governed mainly by the level of oil and gas drilling activities, particularly in the gulf coast area, both onshore and offshore. Drilling activity has increased during the past year. We have no significant leonardite supply contracts with individual customers.

Status of Products, Services or Industry Segments in Development

We own all the stock of Western Star Drilling Company (WSDC), a North Dakota corporation formed to provide contract oil and gas well drilling services. WSDC's drilling equipment can be expanded to allow a greater realm of project and drilling technology capabilities. We may devote resources to this segment if warranted by economic conditions in the drilling industry.

We also own land under seven patented mining claims in Arizona, as well as a minor amount of geothermal and other mineral rights in Oregon. We do not expect to devote any substantial resources to hard mineral or geothermal exploration or development in 2006; however, under a lease agreement, the Arizona property is being mined for commercial rock production. (See Item 2.)

Sources and Availability of Raw Materials and Leases

Maintaining sufficient leasehold mineral interests for oil and gas exploration and development is a primary continuing need in the oil and gas business. We believe that our current undeveloped acreage is sufficient to meet our presently foreseeable oil and gas leasehold needs. Maintaining sufficient leasehold mineral interests for leonardite mining is also a continuing need for our mining and manufacturing of leonardite products. We believe the leonardite held under our current leases is sufficient to maintain our historical output for many years. In December 2005, we received final approval for a new mining permit to develop 160 acres of the Logical Mining Unit (LMU) created in 1994. This permit involves regulations by both the North Dakota Public Service Commission and the United States Department of the Interior, Bureau of Land Management (BLM). (See Item 2.)

Major Customers

In 2005, we sold our crude oil to 15 purchasers. Plains Marketing Canada, L.P. and Flint Hills Resources were the major purchasers, accounting for approximately 47% and 37%, respectively, of our oil and gas revenue in 2005 or approximately 35% and 27%, respectively, of our total operating revenue. We believe there are other crude oil purchasers to whom we would be able to sell our oil, if any of our current purchasers discontinued purchasing from us.

In 2005, we sold leonardite products to 36 customers. The largest customer in 2005 for leonardite products made purchases totaling 15% of our mining and manufacturing revenue or approximately 2% of our total operating revenue.

In 2005, WSDC had seven customers. The largest customer accounted for approximately 35% of our drilling revenue or approximately 6% of our total operating revenue.

Backlog Orders, Research and Development

We do not have any material long-term or short-term contracts to supply leonardite products. When we are in production, all orders are reasonably expected to be filled within three weeks of receipt. From time to time, we enter into short-term contracts to deliver any quantities of oil or gas; however, no significant backlog exists. Our oil and gas division order contracts and any off-lease-marketing arrangements are typical of those in the industry with 30 to 90 day cancellation notice provisions. They generally do not require long-term delivery of fixed quantities of oil or gas. We have not spent any material time or funds on research and development and do not expect to do so in the foreseeable future.

Competition

Oil and Gas In addition to being highly speculative, the oil and gas business is intensely competitive among the 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 find more potentially productive prospects. However, we believe we have the ability to obtain leasehold interests, which will be sufficient to meet our oil and gas needs in the foreseeable future.

Leonardite Products Uses and specifications of leonardite-based drilling mud additives are subject to change if better products are found. Our leonardite products compete with leonardite and non-leonardite products used as additives in numerous types of drilling mud. In addition, leonardite deposits are available in other areas within the United States, and competitors may be able to enter the leonardite business with relative ease. At the present time, similar products are marketed by other companies who mine, process and market leonardite products. Competition lies primarily in delivery time, transportation costs, quality of the product, performance of the product when used in drilling mud and access to high-quality leonardite deposits. In addition, higher fuel prices can significantly affect our leonardite operations, because our processing which requires heat is located in a colder climate. The market for drilling mud additives and the demand for our leonardite products remain strong. However, we have been absent from the market since May 17, 2005, when a fire caused extensive damage to our processing facility. In the future, we may face difficulty in reestablishing meaningful leonardite sales, as all of our leonardite customers have used alternative suppliers or products since May 2005.

Contract Drilling The contract drilling business is highly competitive. Contract drilling competition involves price, rig availability and capability, rig condition, reputation, customer relations and other factors. However, we believe there is a current shortage of drilling rigs available in shallow drilling areas of the Williston Basin.

Contract drilling and oil and natural gas activities are subject to a number of risks and hazards. These could cause serious injury or death to persons, suspension of drilling operations, serious damage to equipment or property of others, and damage to producing formations in surrounding areas. Our operations could also cause environmental damage, particularly through oil spills, gas leaks, discharges of toxic gases or extensive uncontrolled fires. In addition, we could become subject to liability for reservoir damages. The occurrence of a significant event, including pollution or environmental damage, could materially affect our operating results and financial condition. We believe we are adequately insured or indemnified against normal and foreseeable risks in our drilling operations in accordance with industry standards. However, such insurance or indemnification may not be adequate to protect us against liability from all consequences of well disasters, extensive fire damage or damage to the environment. Likewise, we cannot assure that we will be able to maintain adequate insurance in the future at reasonable rates or that any particular types of coverage will be available.

Environmental Regulations

All of 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 oil and gas business segment is affected by diverse environmental regulations including those regarding the disposal of produced oilfield brines, other oil-related wastes, and 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 and a number of others. 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 those of our peers and environmental compliance costs will be recovered in the marketplace. During 2005, 2004 and 2003, environmental compliance costs identified to an actual account were $6,774, $21,471 and $6,795, respectively. However, that is materially less than the real costs, because compliance costs are complex and difficult to differentiate in a system of invoicing.

Our leonardite mining and processing segment is also subject to an abundant number of federal, state and local environmental regulations, particularly those concerned with air contaminant emission levels of our processing plant and mine permit and reclamation regulations pertaining to surface mining at our leonardite mine. We believe that maintenance of acceptable air contaminant emission levels at our processing plant could become more costly in the future if plant production increases substantially above levels experienced over the past several years. Management believes significantly higher plant utilization would increase emission levels and could make it necessary to replace or upgrade air quality control equipment. Environmental compliance costs that might be required to upgrade air quality control equipment cannot be reasonably estimated, because future regulatory requirements are unknown.

Foreign Operations and Export Sales

We have no production facilities or operations in foreign countries but have exported leonardite products to foreign countries including Mexico, Italy and Spain. Some of our leonardite products are also sold to distributors in the United States who in turn export these products.

Employees

At March 16, 2006, we had 13 full-time employees. Our employees are not represented by any unions or other collective bargaining agreements, and we believe our employee relationships are excellent.

Risk Factors

Our operations are subject to a variety of risks, including the following:

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 depleted, as has occurred over the past few years. We compete with a number of exploration and production companies that possess greater financial resources than are available to us. We may not be able to economically compete for oil and gas properties due to a lack of capital and inability to obtain adequate financing, which may be required to fund prospect generation, drilling operations and property acquisitions. To the extent financing is obtained, it may not be on terms beneficial to our stockholders.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production is the primary factor in determining our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories and pipeline access to markets;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices will also negatively impact the value of our proved reserves. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. Approximately 42% of our 2005 oil and gas production came from two fields. Any substantial decline in production from any one field would result in lower revenue to us.

We face significant competition.

We operate in a highly competitive environment. 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 labor required to develop and operate such properties, and in the marketing of oil and gas to end-users. Many of our competitors have financial and other resources, which are substantially greater than ours. In addition, many of our 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 compete in attracting and retaining technical personnel, including geologists, geophysicists and other specialists.

We also face the same competitive matters discussed above with respect to our leonardite operations.

Our reported reserves of oil and gas represent estimates, which may vary materially over time due to many factors.

Generally. Our estimated reserves may be subject to downward revision based upon future production, results of future development, prevailing oil and gas prices, 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 our proved reserves and the present value of such reserves are based upon various assumptions about future production levels, prices and costs that may prove to be incorrect over time. Any significant variance from the assumptions could result in material differences in the actual quantity of our reserves and amount of estimated future net cash flows from our estimated oil and gas reserves.

Proved Reserves; Ceiling Test. A deterioration of oil or gas prices could result in our recording a non-cash charge to earnings at the end of a quarter or year. Our proved reserve estimates are based upon an independent analysis of our oil and gas properties and are subject to rules set by the SEC. We periodically review the carrying value of our oil and gas properties under the full cost accounting rules of the SEC. Under these rules, capitalized costs of oil and gas properties may not exceed the present value of estimated future net cash flows from proved reserves, discounted at 10%, plus the lower of cost or fair market value of unproved properties as adjusted for related tax effects. At the end of each quarter, the test is applied using unescalated prices in effect at the applicable time and may result in a write-down if the "ceiling" is exceeded, even if prices decline for only a short period of time. We have made write downs of the carrying value of our oil and gas properties on our financial statements in the past due to low prices, and may do so in the future.

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

To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of price increases above the levels of the hedges during certain time periods. From time to time, we have engaged in hedging activities with respect to some of our projected oil and gas production through financial arrangements designed to protect against price declines, such as swaps, collars and futures agreements. We currently are not a party to any hedging contracts but may engage in hedging in the future.

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our 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. Our 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. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic and other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company. We may elect not to obtain insurance, if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could adversely affect us.

We face extensive government regulation, which can negatively impact the success of our operations and financial success.

The oil and gas and mining industries are extensively regulated by federal, state and local authorities. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of our oil, gas and leonardite production. Substantial penalties may be assessed for noncompliance with various applicable statutes and regulations, and the overall regulatory burden to us increases our cost of doing business and, in turn, decreases our profitability. State and local authorities regulate various aspects of oil and gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment, and restoration.

We are dependent upon the services of our Chief Executive Officer.

We are highly dependent on the services of our Chief Executive Officer, Jeffrey P. Vickers. We do not have an employment agreement with Mr. Vickers, nor do we carry any key man life insurance on Mr. Vickers. The loss of his services would likely negatively impact our operations.

ITEM 2. PROPERTIES

Our properties consist of five main categories: Office, oil and gas exploration and production, oil and gas drilling rig, leonardite plant and mine, and our Reymert property. Certain of these properties are mortgaged to our bank. See Note F to the Consolidated Financial Statements included herein under Item 7 for further information.

Office

We own an 18,000 square foot office building, which is located on a one-acre lot in Williston, North Dakota. We use about 9,000 square feet of the building and rent the remainder to unaffiliated businesses. In 2004, we purchased a commercial lot behind our building that is approximately one-acre.

Oil and Gas Exploration and Production

We own developed oil and gas leases totaling 21,901 gross (16,019 net) acres as of December 31, 2005, plus associated production equipment. We also own a number of undeveloped oil and gas leases. The acreage and other additional information concerning our oil and gas operations are presented in the following tables.

Estimated Net Quantities of Oil and Gas and Standardized Measure of Future Net Cash Flows 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 O to the Consolidated Financial Statements. The estimates are based upon the reports of Sproule Associates Inc. and Broschat Engineering and Management Services, independent petroleum-engineering firms. We have no long-term supply or similar agreements with foreign governments or authorities, and we do not own an interest in any reserves accounted for by the equity method.

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 last three fiscal years, the average sales price per unit sold and the average production cost per unit are presented below.

Oil & Gas

YEAR	NET OIL PROD. (BBLS)	NET GAS PROD. (MCF)	NET OIL & GAS PROD. (BOE)*	AVERAGE OIL SALES PRICE PER BBL	AVERAGE GAS SALES PRICE PER MCF	AVERAGE PROD. COST PER BOE**
2005	119,450	7,586	120,714	$ 48.37	$ 6.08	$ 19.08
2004	122,939	5,351	123,831	$ 36.05	$ 3.79	$ 15.53
2003	135,865	8,234	137,237	$ 26.42	$ 3.06	$ 13.02

*Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (6 MCF) of natural gas equal to one barrel of oil equivalent (1 BOE).
**Average production cost includes lifting costs, remedial workover expenses and production taxes.

Gross and Net Productive Wells As of December 31, 2005, 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
113	88.22	25	25.00	138	113.22

*There are no wells with multiple completions. A gross well is a well in which a working interest is owned. The number of net wells represents the sum of fractional 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, 2005, we had total gross and net developed and undeveloped oil and gas leasehold acres as set forth below. The developed acreage is stated on the basis of spacing units designated by state regulatory authorities.

Leasehold Acreage*

	DEVELOPED		UNDEVELOPED		TOTAL	
	GROSS	NET	GROSS	NET	GROSS	NET
Montana	9,320	7,666	31,733	32,479	41,053	40,145
North Dakota	12,581	8,353	28,684	13,735	41,265	22,088
ALL STATES	21,901	16,019	60,417	46,214	82,318	62,233

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

Exploratory Wells and Development Wells Set forth below for the last three fiscal years ended December 31, 2005, is information concerning the number of wells we drilled during the years indicated.

YEAR	NET EXPLORATORY WELLS DRILLED		NET DEVELOPMENT WELLS DRILLED		TOTAL NET PRODUCTIVE OR DRY WELLS DRILLED*
	PRODUCTIVE	DRY	PRODUCTIVE	DRY	
2005	0.00	1.00	1.10	0.00	2.10
2004	0.10	0.00	0.92	0.00	1.02
2003	0.00	1.00	1.99	0.00	2.99

*Horizontal re-entries of existing wells are counted as a new well drilled.

Present Activities At March 15, 2006, GeoResources did not have any wells in the process of drilling, but we do have one drilling permit in progress.

Supply Contracts or Agreements We are not obligated to provide a fixed or determinable quantity of oil and gas in the future under any existing contract or agreement, beyond the short-term contracts customary in division orders and off lease marketing arrangements within the industry.

Reserve Estimates Filed with Agencies Information concerning the Company's estimated proved oil and gas reserves and discounted future net cash flows applicable thereto for fiscal 2005, 2004 and 2003 is included as unaudited information in Note O to the Consolidated Financial Statements under Item 7 of this report. We did not provide any reserve information to any federal agencies in 2005 other than to the SEC.

Oil and Gas Drilling Rig During 2001, we purchased and retro-fitted a drilling rig, which is capable of drilling to 8,000 feet. Four of its primary components are a Drilling Structures Inc. mast rated at a 350,000 pound hook load, an Emsco GB-250 drawworks and Emsco DB-550 and D-375 mud pumps. It is our expectation that this rig will only be utilized to drill wells located in the United States portion of the Williston Basin for us and for other operators.

During 2005, the rig was utilized to drill two wells for us and eight wells for other operators. A rig is considered to be utilized when it is operated or being moved, assembled, or dismantled under contract. The optimum utilization of the WSDC rig is the drilling of approximately 20 wells per year of the type and depth that are typical in the shallower portions of the Williston Basin. More information of WSDC's drilling operations is included in Management's Discussion.

Leonardite Plant and Mine

The site of our leonardite plant covers about nine acres located one mile east of Williston in Williams County, North Dakota. We own this site and an additional 20 acres of undeveloped property. The plant has approximately 11,500 square feet of floor area consisting of warehousing and processing space. Within the plant is equipment that was able to process and ship approximately 1,500 tons of leonardite products per month until a May 17, 2005, fire destroyed the main control room and damaged other areas of the facility. At this time, finished leonardite products cannot be produced until the electrical controls are replaced and other repairs are performed. We have informed our insurance company that we plan to restore our leonardite facility and return the plant to operation; however, the timing of these repairs is not certain at this time, because the scope of the repairs has not been fully determined due to processing changes we are investigating. Our 1982 processing facility used a fluid bed drying process fueled by natural gas that may not be the optimal process to use in today's markets. Our plant restoration is affected by several other factors including operating with older equipment, maintaining better quality control for our products and meeting the EPA standards for our industry. The market for drilling mud additives is strong at present; however, future market conditions, competition in leonardite based drilling mud additives, or future unforeseeable events and occurrences could cause us to change our plans and affect how, and if, the restoration is done. For the present time, we intend to continue to pursue small raw material sales of leonardite and complete engineering design and specification for needed equipment replacement. There are also external factors that affect our sales, with the biggest factor probably being competition. Plants that have been built which are more centrally located can ship their product less expensively than we can. Finished product leonardite sales for the past three years are shown below.

YEAR	FINISHED PRODUCTS (TONS)	AVERAGE SALES PRICE PER TON
2005	5,667	$ 143.06
2004	10,093	$ 127.88
2003	6,558	$ 125.38

Our leonardite mining properties consist of a developed lease from private parties and a newly permitted lease from the BLM. The leased lands are located about one mile from our plant site in Williams County, North Dakota. The private-party (fee) lease totals approximately 160 acres and requires a royalty payment per ton scaled to the Producer Price Index, which was approximately $0.75 for the past three years. All recoverable coal was removed from the private-party lease in 2005. On December 2, 2005, we received final approval for a new mining permit to develop 160 acres on a Logical Mining Unit (LMU) created in 1994. This permit involves regulation by both the North Dakota Public Service Commission and the BLM. The federal lease requires a minimum royalty of $3.00 per acre or production royalty of 12.5% of value extracted. Although for 40 years our leonardite proven reserves have never been established from independent sources, with the new mine approval the BLM does approve "estimated" recoverable reserves in our permit area of 600,000 tons. We believe that the leonardite contained in the 160-acre federal lease is sufficient to supply our plant's raw material requirements for many years, and that before these reserves were to be exhausted, we would be able to acquire other fee or federal coal leases in the same area.

Reymert Property

We own seven patented mining claims and 15 unpatented mining claims in the Tonto National Forest in Pinal County, Arizona. These claims, known as the Reymert Property, produced silver sporadically since the 1880's. On May 1, 2002, we entered into a License Agreement-Lease Agreement with Gila Rock Products, L.L.C. (GRP), an Arizona limited liability corporation. GRP is using this property for producing and marketing decorative rock, boulders, riprap, road-base material and similar commercial rock products. We receive a 10% royalty of gross selling prices on all rock products produced and sold from the property or a minimum royalty of $250 per month. Royalties received relating to the Reymert Property were about $36,000, $16,000 and $3,400 for 2005, 2004 and 2003, respectively. We have no plans to devote significant financial resources to this property in 2006.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in a bankruptcy case with respect to a preference claim brought on November 8, 2002, in the United States Bankruptcy Court, Southern District of Texas, Houston Division (adversary proceeding number 02-03827, In Re: Ramba, Inc., Lowell T. Cage, Trustee v. GeoResources, Inc.). The bankruptcy trustee of a former leonardite customer, Ambar, Inc. (n/k/a Ramba, Inc.) has sued us for approximately $139,000 in an amended preference claim in Bankruptcy Court. Our defense was vigorous, and on September 1, 2004, the District Court granted our motion for summary judgment. The Plaintiff perfected an appeal to the Fifth Circuit, which ruled in favor of us except for $28,400. At an April 7, 2006, hearing with the Judge and the Plaintiff; our attorneys plan to explore the possibility of a settlement. See Note J to the Consolidated Financial Statements included herein under Item 7 for further information.

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

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

During the fourth quarter of 2005, no matter was submitted to a vote of our security holders through the solicitation of proxies or otherwise.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Our Common Stock trades on the Nasdaq SmallCap Stock Market under the Symbol "GEOI". The following table sets forth for the period indicated the lowest and highest trade prices for our Common Stock as reported by the Nasdaq SmallCap Stock Market. These trade prices may represent prices between dealers and do not include retail markups, markdowns or commissions.

CALENDAR		TRADE PRICE HIGHEST	TRADE PRICE LOWEST
2005	4th Quarter	$ 11.36	$ 6.81
	3rd Quarter	$ 17.85	$10.47
	2nd Quarter	$ 17.96	$ 7.35
	1st Quarter	$ 11.08	$ 2.37
2004	4th Quarter	$ 6.22	$ 2.10
	3rd Quarter	$ 2.55	$ 1.56
	2nd Quarter	$ 2.94	$ 1.76
	1st Quarter	$ 2.50	$ 1.61

As of March 15, 2006, there were approximately 800 holders of record of our Common Stock. We believe that there are also approximately 3,300 additional beneficial owners of Common Stock held in "street name".

We have never declared or paid a cash dividend on our Common Stock, nor do we anticipate that dividends will be paid in the near future. Further, certain of our financing agreements restrict the payment of cash dividends. See Note F to the Consolidated Financial Statements for further information.

Equity Compensation Plan Information

The following sets forth information as of March 15, 2006, concerning our compensation plan under which shares of our common stock are authorized for issuance.

In 2005, employee options exercised totaled 16,292 shares at $2.37 and 25,000 shares at $2.31.

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:			
1993 Employees' Incentive Stock Option Plan*	110,208	$ 2.34	-0-
2004 Employees' Stock Incentive Plan	-0-	N/A	N/A
Equity compensation plans not approved by security holders:	N/A	N/A	N/A

*The term of this plan expired on February 17, 2003. Thus, no further options may be granted under the plan.

ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OR PLAN OF OPERATION

OVERVIEW

We operate through three primary segments: a) oil and gas exploration, development and production; b) oil and gas drilling; and c) mining of leonardite (oxidized lignite coal) and manufacturing of leonardite based products, which are sold primarily as oil and gas drilling mud additives. Our oil and gas strategy is focused on the exploitation of existing oil and gas fields. Our drilling operations focus is development of our customer base and increasing our project capabilities. Our major leonardite products are oil and gas drilling mud additives. When in operation, we also concentrated on the expansion of customers and products in our leonardite operations. See Note B to the Consolidated Financial Statements for financial information about our business segments.

BUSINESS ENVIRONMENT AND RISK FACTORS

This discussion and analysis of financial condition and results of operations, and other sections of this report, contain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are based on management's beliefs, assumptions, current expectations, estimates and projections about the oil and gas industry, the leonardite industry and the oil well drilling industry, the economy and about us. Words such as "may," "will," "expect," "anticipate," "estimate" or "continue," or comparable words are intended to identify forward-looking statements. These statements are not guarantees of future performance and involve risks, uncertainties and assumptions that are difficult to predict with regard to timing, extent, likelihood and degree of occurrence. Therefore, our actual results and outcomes may materially differ from what may be expressed or forecasted in our forward-looking statements. Furthermore, we undertake no obligation to update, amend or clarify forward-looking statements, whether as a result of new information, future events or otherwise.

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 supply and demand, which affect commodity prices for oil; the timing and extent of our success in discovering, acquiring, developing and producing oil, natural gas and leonardite reserves; risks inherent in the drilling and operation of oil and natural gas wells and the mining and processing of leonardite products; future production and development costs; the effect of existing and future laws, governmental regulations and the political and economic climate of the United States; and conditions in the capital markets. See also "Risk Factors" in Item 1 to this report for factors that could cause results to differ materially from forward-looking statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

General. The preparation of financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, management evaluates its estimates, including evaluations of any allowance for doubtful accounts and impairment of long-lived assets. Management bases its estimates on historical experience and various other assumptions it believes to be reasonable under the circumstances. The results of these evaluations form a basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, management believes that its estimates are reasonable given currently available information. The following critical accounting policies relate to the more significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Gas Properties

We employ the full cost method of accounting for our oil and gas production assets. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized. The sum of net capitalized costs plus estimated future development and dismantlement costs is depleted on the unit-of-production based on our total proved oil and gas reserves as estimated by independent petroleum engineers.

Proved reserves are the quantity of oil and gas that may be recovered in the future from known reservoirs under economic and operating conditions existing as of the end of the year. Reserve estimates change over time as additional information becomes available and assumptions regarding future events are revised. Reserve engineering is a subjective process that is dependent on the quality of available data on engineering and geological interpretation and judgment and on assumptions of oil and gas commodity prices, production costs and future development and dismantlement costs.

The independent petroleum engineers who estimate our proved reserves rely primarily on the historical volumetric production from our properties or similar properties in the area. Also, it is assumed that future oil and gas prices, production costs, and development and dismantlement costs will be the same as those actually prevailing at the end of the year, and that those prices and costs will remain constant for all future periods. Our future development projects are based on the undeveloped properties that we own as of year-end and on our long-term capital expenditures budget.

All of the underlying estimates and assumptions utilized in estimating our proved reserves and future development and dismantlement costs will change over time. However, the factor that has historically had the greatest impact on the estimation of our proved reserves is the actual year-end oil commodity price that is assumed to remain constant for all future years. Oil prices are volatile and influenced by numerous factors beyond our control. See also "Risk Factors" in Item 1 to this report for further information regarding oil prices and reserves.

Also under the full cost method, we are required to record a permanent impairment provision if the net book value of our oil and gas properties less related deferred taxes exceeds a ceiling value equal to the present value of the future cash inflows from proved reserves, tax effected and discounted at 10%. The ceiling test is computed at the end of each quarter. All of the factors discussed in the three paragraphs above also affect the determination of the present value of the future cash inflows from proved reserves. The oil and gas prices used in calculating future cash inflows are based upon the market price on the last day of the accounting period. Oil and gas prices are generally volatile, and if the market prices at a period end date have decreased, we may have to record impairment. We have recorded impairments in the past as a result of low oil prices.

Impairment of Long-Lived Assets

Our long-lived assets consist of property and equipment. Other than oil and gas properties previously discussed, long-lived assets with an indefinite life are reviewed at least annually for impairment, while other long-lived assets are reviewed whenever events or changes in circumstances indicate that carrying values of these assets are not recoverable. Impairment is recognized when the estimated future net cash flows (undiscounted and without interest charges) from the asset are less than the carrying amount of the asset. Our estimate of future net cash flows is primarily based upon the assumption that the trends of actual historical cash flows will continue in the future for the projected remaining physical life of the property. No impairment losses have been recognized on long-lived assets.

Asset Retirement Obligation

If a reasonable estimate of the fair value can be made, we will record a liability for legal obligations associated with the future retirement of tangible 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 our 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.

We have recorded asset retirement obligations related to our oil and gas properties. The fair value of the liability is estimated based on historical experience in plugging and abandoning wells, federal and state regulatory requirements, estimated productive lives of wells, estimates of the cost to plug and abandon wells in the future, and the Company's credit-adjusted risk-free interest rate. Any or all of those factors may change over time as additional information becomes available. The effect of such changes on our estimate of the liability is recorded in the period in which the change is made. The factor that is most likely to have a material effect on our estimated liability is the estimated productive lives of wells. This estimate is based on the study by our independent petroleum engineers discussed in the oil and gas properties section above.

We have also identified other asset retirement obligations that are not recorded because a reasonable estimate of the fair value cannot be made due to the indeterminate life of the associated assets. There are no assets legally restricted for the purpose of settling asset retirement obligations.

Accounting for Income Taxes

As part of the process of preparing our consolidated financial statements, we are required to record income tax expense. This process involves calculating our current taxes payable and assessing temporary differences resulting from the differing treatment of items for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within our consolidated balance sheet. We regularly estimate the recoverability of our deferred tax assets based on projected future taxable income and the expected timing of the reversals of existing temporary differences. Because of the differing treatment of many items for tax and accounting purposes, we may incur losses for tax purposes while reporting income for accounting purposes. We do not have a history of consistently generating income for tax purposes and accordingly, we do not project that we will generate future taxable income. Therefore, the recoverability of our deferred tax assets is based solely on the future reversal of existing timing differences. Accordingly, we have recorded a valuation allowance for the excess of our statutory depletion carryforward over the future reversal of existing timing differences. To the extent we increase or decrease the allowance in a period, we include an expense or benefit within the tax provision in the statement of operations.

OFF BALANCE SHEET ARRANGEMENTS

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

NEW ACCOUNTING STANDARDS

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard ("SFAS") No. 151, "Inventory Costs, an Amendment of ARB No. 43, Chapter 4". The statement requires abnormal amounts of freight, handling costs, idle facility expense and spoilage to be recognized as current period expenses. This statement became effective for the Company on January 1, 2006. The adoption of this statement is not expected to have a significant impact on the Company's results of operations, financial position or cash flows.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". This statement replaces SFAS No. 123, "Accounting for Stock Based Compensation" and supersedes ABP Opinion No. 25, "Accounting for Stock Issued to Employees". It establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation, eliminating the alternative to use APB No. 25's intrinsic value method. The statement became effective for the Company on January 1, 2006. In March 2005, the SEC released Staff Accounting Bulletin No. 107 "Share-Based Payment", which provides interpretive guidance related to the interaction between SFAS 123 (R) and certain SEC rules and regulations. It also provides the SEC staff's views regarding valuation of share-based payment arrangements. Management believes that SFAS No. 123 (R) and SAB No. 107 will have an impact on future share-based transactions of the Company but cannot determine the impact at this time.

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, and Amendment of APB No. 29". This statement amends and clarifies financial accounting for nonmonetary exchanges by requiring that most exchanges of productive assets be accounted for at fair value. With certain exceptions, companies can no longer account for nonmonetary exchanges at book value with no gain or loss recognized. This statement became effective for the Company on January 1, 2006, and may impact the Company's consolidated financial position and results of operations in future periods if such nonmonetary exchanges occur.

In March 2005, the FASB issued Interpretation No. 47 (FIN 47), "Accounting for Conditional Asset Retirement Obligations", an Interpretation of FASB Statement No. 143, which clarifies the accounting for conditional asset retirement obligations as used in SFAS No. 143, "Accounting for Asset Retirement Obligations". A conditional asset retirement obligation is an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Under FIN 47, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligations if the fair value of the liability can be reasonably estimated. Any uncertainty about the amount and/or timing of future settlement should be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value. The provisions of FIN 47 are effective for years ending after December 31, 2005. The Company is currently evaluating the impact of FIN 47 on its consolidated financial statements.

In May 2005, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections", a replacement of APB Opinion No. 20 and FASB Statement No. 3. This Statement provides guidance on accounting for reporting of accounting changes and error corrections. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The Company does not expect the impact of adopting SFAS No. 154 to have a material effect on its consolidated results of operations or financial position.

RESULTS OF OPERATIONS

The following table sets forth the selected financial data during the last five years.

	2005	2004	2003	2002	2001
Operating Revenue	$ 7,994,659	$ 6,820,125	$ 4,842,952	$ 3,987,686	$ 4,216,402
Net Income	2,179,473	1,105,846	446,563	91,374	41,818
Net Income Per Share, Basic	.58	.30	.12	.02	.01
AT YEAR END:					
Total Assets	14,699,720	12,720,171	11,584,273	9,048,200	8,201,719
Long-term Debt	177,638	1,205,729	1,599,479	1,910,228	1,035,228
Current Maturities	523,941	518,750	479,457	132,260	125,000
Working Capital (deficit)	978,376	85,081	(172,970)	310,516	(223,782)
Stockholders' Equity	9,355,567	7,079,732	5,973,886	5,616,211	5,536,009

Comparison of 2005 to 2004 for Oil and Gas Operations

	Year 2005	% Increase (Decrease) From 2004	Year 2004	% Increase (Decrease) From 2003
Oil and gas production sold (BOE)	120,714	(2.5%)	123,831	(9.8%)
Average revenue per BOE	$ 48.25	34%	$ 35.95	37%
Oil and gas revenue	$ 5,824,049	31%	$ 4,452,114	23%
Production costs	$ 2,303,238	20%	$ 1,922,479	7.6%
Average production cost per BOE	$ 19.08	23%	$ 15.53	19%
Depreciation, depletion and amortization	$ 556,171	(4.1%)	$ 580,106	2.5%
Operating income before SG&A	$ 2,964,640	52%	$ 1,949,529	54%

The relative changes in revenue, production costs and other measures for oil and gas operations for 2005 and 2004 are shown in the chart above. The source of all of our oil and gas revenue is our sales of oil in 42-gallon barrels, abbreviated BBL, and gas in thousands of cubic feet at atmospheric conditions, abbreviated MCF. We convert gas to its approximate oil equivalent by its relative energy content of six MCF to 1 BBL of oil to equate total oil and gas sales into "barrels of oil equivalent", abbreviated BOE.

Oil and gas production sold during 2005, expressed in BOE, crept up each quarter to total 120,714 BOE just 3,100 BOE or 2.5% less than the total volume in 2004. Although 2005 total oil and gas production did not increase over 2004, our sales through the year did show small steady growth each quarter, from the first quarter of the year when they were 9% less than first quarter 2004 to the fourth quarter when they were 6% larger than the same quarter in 2004. Because our 2005 drilling was not accomplished until the end of the year, the small quarterly growth during the year was entirely due to workover activity targeted primarily at returning shut-in wells to production. Both of our operated drilling projects were performed in the fourth quarter of 2005, the first a 100% working interest development well in the Leonard Field and the second a 100% working interest exploratory well in our Kramer prospect, both of which are in Bottineau County, North Dakota. The exploratory well did not find the zone we hoped would be present and was plugged as a dry hole, but the development well had encouraging indications of productivity and had casing set for a completion in January 2006. Since the end of 2005, that well was completed, and it had gross production of 2,100 BBLS in February 2006, which was its first full month of production. In summary, 2005 production, workovers and production enhancements of existing wells held production essentially stable with 2004, and drilling resulted in new production that is increasing production in 2006 compared to 2005.

Although production was essentially stable for 2005 compared to 2004, the average value of our sales was dramatically higher leading to a significant increase in our oil and gas revenue. Revenue per BOE was $12.30 or 34% higher for 2005 compared to 2004. Worldwide oil and gas values were the single most important aspect of our operating performance and financial results during 2005. The daily NYMEX price of oil and gas we sell affects nearly every facet of our oil and gas operations.

Oil and gas production costs increased 20% or $381,000 in 2005. "Ad valorem" production tax, which is a fixed percentage of value produced at the wellhead, was a sizeable contributor to the increase. In 2005, $87,000 or 23% of the $381,000 increase in production costs was due to ad valorem taxes. In addition, our expenses were generally higher in almost all categories due to the higher demand for oilfield goods and services, which drives up vendor prices. Our four largest production costs are generally contract services, fuel and power, repairs and maintenance and well service or workover costs. Also, our higher per barrel revenue allowed us to increase discretionary spending. These discretionary costs and the above taxes would be reduced if oil prices decrease. Discretionary cost reductions have limitations however, as many oil and gas production costs are fixed costs, or fixed costs per BOE. Our largest discretionary costs in 2005 were expensed costs primarily related to returning shut-in wells to production. Most costs related to repairing or enhancing idle wells are expensed versus being capitalized, so our higher level of workover activities increased production costs. Workover and production enhancement costs were about $125,000 or 77% higher in 2005 compared to 2004 and were about 33% of our total higher production costs for 2005. Due to the higher production costs discussed above, 2005 average production cost per barrel increased $3.55 or 23% over 2004.

The margin between average revenue per BOE and average cost per BOE was $29.17 in 2005 compared to $20.42 in 2004. Oil and gas depreciation depletion and amortization (DD&A) in 2005 was $24,000 or 4% lower compared to 2004. As a result of all revenues and expenses, operating income before S&A for the oil and gas segment of our operations increased to $2.96 million in 2005 compared to $1.95 million for 2004.

Looking forward, we expect 2006 to be a year of high activity for the oil and gas industry including our operations. We have one drilling permit in progress, and have targeted to drill a total of three operated wells in Bottineau County, North Dakota. We believe most oil and gas operating companies in our areas of operations will increase their exploration and production activities in 2006, placing a strain on the availability of oil and gas related labor, equipment and services, which may adversely affect our ability to reach our 2006 goals.

Comparison of 2005 to 2004 for Drilling Operations

	Year 2005	% Increase (Decrease) From 2004	Year 2004	% Increase (Decrease) From 2003
Operating days	142	6.8%	133	137%
Drilling revenue	$ 1,359,872	26%	$ 1,077,367	165%
Average revenue per day	$ 9,577	18%	$ 8,094	12%
Drilling Costs	$ 1,258,258	25%	$ 1,009,051	173%
Average costs per day	$ 8,861	17%	$ 7,581	15%
Depreciation, depletion and amortization	$ 151,847	18%	$ 128,335	117%
Operating income (loss) before SG&A	$ (50,233)	N/A	$ (60,019)	(163%)

All amounts in the drilling operations table above are presented in conformance with our financial statements. Accordingly, Western Star Drilling Company's (WSDC) revenue and expense from the drilling of GeoResources' wells or wells in which it participated are eliminated in consolidation of the financial statements, and the cost of those wells is capitalized by GeoResources in oil and gas properties, using the full cost method of accounting. Therefore, the amounts shown in the table represent only drilling operations performed by WSDC for companies other than GeoResources.

In 2005, WSDC's operations consisted of 162 operating days drilling two wells for us and eight wells for other operators. GeoResources participated with a 10% interest in one of the other operator's wells. This compares to 148 operating days drilling one well for GeoResources and five for other operators in 2004. Total footage drilled was 56,987 feet in 2005 versus 40,270 feet in 2004. The well counts used in this discussion are gross wells that were drilled in each respective year either for other operators and for GeoResources. The operating days and all other parameters in the table, however, are the net drilling days in each year associated only with "outside drilling" as discussed in the paragraph above.

Drilling days for projects other than GeoResources increased 9 days or 6.8% to 142 days in 2005 compared to 133 days in 2004. On a percentage utilization basis, the 2005 usage was 39% compared to 36% in 2004. Due to weather, road conditions, truck scheduling, and other factors, annual utilization of 70% to 80% would be as high as we might hope to attain.

Due to higher rig utilization, drilling revenue was $1,360,000 in 2005 compared to $1,077,000 in 2004, a 26% increase. Drilling costs also increased in close proportion to revenue. Part of the drilling cost increases was due to higher rig utilization, rig repairs and discretionary upgrading as we continue to make rig improvements using drilling cash flow. Revenue and costs per day were also both proportionately higher. The costs per day were higher due to the factors mentioned above, and the per day revenue increased due to rig improvements and the ability to increase our day-work rate. Average revenue per day is less than the contract day-work rate because operating days include days for "move in, rig up" and "tear out, rig down" days. These days are billed at substantially lower rates than drilling days.

Drilling rig depreciation in 2005 was $151,847 or 18% higher due to the increased number of days the rig was utilized. Operating loss before SG&A in 2005 was $50,233 compared to a loss of $60,019 in 2004. WSDC has value to us over and above its financial profit potential because it facilitates our ability to explore and develop our own properties. Additionally, two of the three wells WSDC drilled in the fourth quarter were for GeoResources, and therefore, they did not impact WSDC's fourth quarter operations in the consolidation of the financial statements.

Comparison of 2005 to 2004 for Leonardite Operations

	Year 2005	% Increase (Decrease) From 2004	Year 2004	% Increase (Decrease) From 2003
Leonardite sold (Tons)	5,667	(44%)	10,093	534%
Average price	$ 143.06	12%	$ 127.88	2.0%
Leonardite revenue	$ 810,738	(37%)	$ 1,290,644	57%
Production costs	$ 907,943	(22%)	$ 1,168,148	37%
Average production costs per ton	$ 160.22	38%	$ 115.74	(11%)
Depreciation, depletion and amortization	$ 43,882	(56%)	$ 99,412	--
Operating income (loss) before SG&A	$ (165,567)	N/A	$ (10,542)	N/A

Production of leonardite was suspended indefinitely due to a fire on May 17, 2005, at our leonardite processing facility. No one was injured in the fire. Although the actual processing equipment was relatively unaffected, the damage to the electrical systems that control the operation of the equipment was significant. Leonardite revenue for the remainder of 2005 was strictly limited to minor sales of raw material for agricultural use.

The leonardite processing facility continued to incur expenses after the fire. Those expenses were primarily related to limited mining and sale of raw material, normal continuing costs such as insurance premiums and maintenance of equipment, and labor costs associated with employees who performed a general clean up and re-conditioning of the entire site and facility. Labor and other costs associated specifically with clean up of the fire damage has been charged to other non-operating expense.

Our insurance carrier determined that the replacement cost value (RCV) of the leonardite facility was $1,375,311, with an actual cash value (ACV) of $735,364. We have received payment for most of the ACV. Because the ACV exceeded the net book value of the facility at the time of the fire plus direct costs incurred because of the fire, we realized a gain from the involuntary conversion of the leonardite facility of $497,743. Receipt of additional insurance proceeds up to the RCV amount is contingent on our compliance with the replacement cost option of our policy that requires us to replace, repair and restore the facility to operations. If such repairs are finished in a reasonable amount of time, our insurance will provide an additional amount up to approximately $640,000 payable as the repairs are completed and invoiced.

On November 17, 2005, we informed our insurance company in writing that we have decided to repair our leonardite facility and restore it to normal operations. The timing of these repairs is not certain at this time because the scope of the repairs has not been fully determined due to processing changes we are investigating. Our 1982 processing facility used a fluid bed drying process fueled by natural gas that may not be the optimal process to use in today's markets. Our plant restoration is affected by several other factors including operating with older equipment, labor concerns, maintaining better quality control for our products and meeting the EPA standards for our industry. We expect insurance proceeds to cover substantially all of the restoration costs. The market for drilling mud additives is strong; however, future market conditions, competition in leonardite based drilling mud additives, or future unforeseeable events and occurrences could cause us to change our plans and affect how, and if, the restoration is done. For the present time, we intend to continue to pursue small raw material sales and complete engineering design and specification for needed equipment replacement.

Our leonardite mining operation has a 240-acre Logical Mining Unit (LMU) that contains 160 acres of BLM leasehold. In December 2005, we were issued a new mining permit and mine plan approvals by the North Dakota Public Service Commission and the BLM. The new mine pit was opened in January 2006. At historical rates, the new mine should provide another 10 to 15 years of production.

Comparison of 2005 to 2004 Consolidated Analysis of the Financial Statements

	Year 2005	% Increase (Decrease) From 2004	Year 2004	% Increase (Decrease) From 2003
Total operating revenue	$ 7,994,659	17%	$ 6,820,125	41%
Cost of operations	$ 4,469,439	9%	$ 4,099,678	36%
Depreciation, depletion and amortization	$ 786,156	(7%)	$ 842,658	11%
Selling, general and administrative	$ 660,204	11%	$ 594,017	11%
Operating income	$ 2,078,860	62%	$ 1,283,772	138%
Other, net	$ 394,214	N/A	$ (60,639)	6%
Income before taxes	$ 2,473,074	102%	$ 1,223,133	154%
Income taxes	$ 293,601	150%	$ 117,287	835%
Net income	$ 2,179,473	97%	$ 1,105,846	148%

Depreciation of general corporate assets in 2005 was $34,000 or 1.6% lower than 2004. General corporate assets include our office building and equipment and our Reymert property.

Selling, general and administrative costs (SG&A) were 11% higher in 2005 due in part to our efforts to increase investor awareness and the early stages of documenting our compliance with the various internal control requirements of Section 404 of the Sarbanes Oxley Act of 2002.

Income tax expense for 2005 was $294,000 or 150% higher than 2004, due in part to the $498,000 non-operating gain recognized on the involuntary conversion of our leonardite facility. Income tax expense for each year is primarily reflective of changes in our tax-deferred assets and liabilities under the provisions of SFAS No. 109. See Notes A and H to the financial statements for further information.

As a result of all the factors discussed above, net income was $2,179,000 or $0.58 per share in 2005 compared to a net income of $1,106,000 or $0.30 per share in 2004.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2005, we had current assets of $3,054,000 compared to current liabilities of $2,076,000 for a current ratio of 1.47 to 1 and working capital of $978,000. This compares to a current ratio of 1.04 to 1 at December 31, 2004, and working capital of $85,000.

During the year ended December 31, 2005, we generated cash flows from operating activities of $2,637,000, which was $317,000 more than the amount generated during 2004. This increase was due to significantly higher cash flows from oil and gas operations that were partially offset by a negative cash flow from leonardite operations. We anticipate that cash flows from operations and funds available under our $3,000,000 revolving line of credit (2004 RLOC) will be sufficient to meet our cash requirements for 2006. The 2004 RLOC had $3,000,000 available for use at December 31, 2005, subject to collateral requirements and will allow borrowings until March 5, 2007, with repayment due by March 5, 2011.

During 2005, our investing activities used $1,398,000 of cash for additions to property, plant and equipment. Approximately $552,000 of these additions was to drill two wells in Bottineau County, North Dakota, and participate in one exploratory well in Mountrail County, North Dakota. We also used approximately $418,000 for capitalized workovers on operated and non-operated wells and $129,000 for the unitization of the Landa West Madison Unit in Bottineau County, North Dakota. Portions of the remaining $299,000 used in investing activities consisted of $85,000 of additional rig equipment, $85,000 for leonardite plant expenditures, $34,000 for unproved oil and gas property costs and $26,000 for proved property acquisition costs. We received $670,000, net of related costs, from our insurance claim related to the leonardite fire.

During 2005, our financing activities consisted of $524,000 of cash utilized for regularly scheduled principal payments under long-term debt agreements, $509,000 for prepayment on long-term debt and $64,000 for payments on capital leases.

We estimate that our capital costs for 2005 relating to our proved developed nonproducing and proved undeveloped oil and gas properties will be approximately $1,200,000. Planned expenditures for 2005 also include delay rentals and other exploration costs of approximately $100,000. Funds expected to be used for 2005 principal payments on our 2001 Oil and Gas loan are $519,000 and $42,000 on WSDC's capital lease obligations. We estimate that future capital costs to repair and restore the leonardite facility will be approximately $1,300,000. This amount would include the RCV of the plant, which we have received from our insurance company ($735,364) plus additional amounts of up to $640,000 payable by our insurance company as the repairs and restoration are completed.

We expect to continue to evaluate possible future purchases of additional producing oil and gas properties and the further development of our properties. We believe our long-term cash requirements for such investing activities and the repayment of long-term debt can be met by future cash flows from operations and, if necessary, possible forward sales of oil reserves or additional debt or equity financing.

ITEM 7. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

See "Index to Consolidated Financial Statements" on page 35.

ITEM 8. DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURES

None.

ITEM 8A. CONTROLS AND PROCEDURES

The Company's Chief Executive Officer and Chief Financial Officer, Mr. J. P. Vickers, has implemented the Company's disclosure controls and procedures to ensure that material information relating to the Company is made known to Mr. Vickers. Our executive officers have evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period. Based on such evaluation, Mr. Vickers concluded that the Company's disclosure controls and procedures are effective in alerting him on a timely basis to material information relating to the Company that is required to be included in our reports filed or submitted under the Securities Exchange Act of 1934. Moreover, there were no changes in internal controls or in other factors that have materially affected or are reasonably likely to materially affect the Company's internal controls over financial reporting.

ITEM 8B. OTHER INFORMATION

None.

PART III

ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTER AND CONTROL PERSONS; COMPLIANCE WITH SECTION 16(a) OF THE EXCHANGE ACT

The following sets forth certain information concerning each of our directors and executive officers:

NAME AND AGE	POSITION(S) WITH THE COMPANY	PERIOD OF SERVICE AS A DIRECTOR OR OFFICER
Jeffrey P. Vickers Age: 53	President, CEO, CFO and Director	Since 1982
Jeffrey B. Jennings Age: 49	Vice President of Land and Finance	Since June 2000
Cathy Kruse Age: 51	Secretary and Director	Since October 1981 (officer); and since June 1996 (director)
Connie R. Hval Age: 45	Treasurer	Since June 2000
H. Dennis Hoffelt Age: 64	Director Member of Audit Committee	From 1967 through June 1986; and since June 1987

NAME AND AGE	POSITION(S) WITH THE COMPANY	PERIOD OF SERVICE AS A DIRECTOR OR OFFICER
Paul A. Krile Age: 77	Director Member of Audit Committee	Since June 1997
Nick Voller Age: 55	Director Member of Audit Committee	Since March 2004
Duane Ashley Age: 57	Director	Since June 1999

All of the directors' terms expire at the next annual meeting of shareholders or when their successors have been elected and qualified. Our executive officers serve at the discretion of the Board of Directors. The Board of Directors has appointed an audit committee consisting of three independent directors who are financial experts, Nick Voller, H. Dennis Hoffelt and Paul A. Krile.

Jeffrey P. Vickers received a Bachelor of Science degree in Geological Engineering with a Petroleum Engineering option from the University of North Dakota in 1978. In 1979, Mr. Vickers joined Amerada Hess Corporation as an Associate Petroleum Engineer in the Williston Basin. In 1981, Mr. Vickers was employed by us as our Drilling and Production Manager where he was responsible for providing technical assistance and supervision of drilling and production operations and generated development drilling programs. He became our President on January 1, 1983. In June 1982, Mr. Vickers became a director.

Jeffrey B. Jennings is Vice President of Land and Finance. Mr. Jennings received a Bachelor of Science in Geological Engineering in 1980 and a Master of Science in Mineral Economics in 1992, from the Colorado School of Mines. He was a consultant for us for two years prior to his employment with us in January 1996.

Cathy Kruse is our Secretary and business office manager. Mrs. Kruse graduated from the Atlanta College of Business in 1977 and was employed as a Legal Assistant for four years prior to her employment with us in May 1981. In June 1996, Mrs. Kruse became a director. Mrs. Kruse serves on the North Dakota Governor's Council for Workforce Development and serves on the Board of Directors for the North Dakota Chamber of Commerce.

Connie R. Hval is our Treasurer and comptroller. Ms. Hval graduated from the University of North Dakota-Williston in December 1980 and became employed with us in January 1981.

H. Dennis Hoffelt is retired. Prior to his retirement Mr. Hoffelt was President of Triangle Electric Inc., Williston, North Dakota, an electrical contracting firm, for over thirty years. He served as one of our directors from 1967 through June of 1986 and was elected as a director again in 1987.

Paul A. Krile has been one of our directors since June 1997. He has been the President and owner of Ranco Fertiservice, a manufacturer of dry fertilizer handling equipment, headquartered in Sioux Rapids, Iowa, for more than the last five years.

Nick Voller has been one of our directors since March 2004. For the past five years, he has been a partner with Voller Brakey Stillwell & Suess, PC, a CPA firm located in Williston, ND.

Duane Ashley has been one of our directors since June 1999. He has been a Senior Salesman for GRACO Fishing and Rental Tool, Inc. and Weatherford Enterra, Inc. for the past five years.

Cathy Kruse is the sister-in-law of Jeffrey P. Vickers. No other family relationship exists between or among any of the officers or nominees. Mr. Joseph Montalban is a non-voting member of our Board of Directors with the right to attend all meetings. There are no arrangements or understandings between any of the directors or nominees and any other person pursuant to which any person was or is to be elected as a director or nominee.

Code of Ethics

Our Board of Directors has adopted a Code of Business Conduct and Ethics ("Code"), a copy of which we filed as Exhibit 14.1 to our Form 10-KSB for the fiscal year ended December 31, 2003.

Our Code provides general statements of our expectations regarding ethical standards that we expect our directors, officers and employees to adhere to while acting on our behalf. Among other things, the Code provides that:

- we will comply with all laws, rules and regulations;
- our directors, officers and employees are to avoid conflicts of interest and are prohibited from competing with us or personally exploiting our corporate opportunities;
- our directors, officers and employees are to protect our assets and maintain our confidentiality;
- we are committed to promoting values of integrity and fair dealing; and
- we are committed to accurately maintaining our accounting records under generally accepted accounting principles and timely filing our periodic reports.

Our Code also contains procedures for our employees to report, anonymously or otherwise, violations of the Code.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors and executive officers, and persons who own more than 10% of our common stock to file with the Securities and Exchange Commission initial reports of ownership and reports of changes in ownership of our common stock. Executive officers, directors and greater than 10% shareholders are required by SEC regulations to furnish us with copies of all Section 16(a) reports they file. To our knowledge, based solely on review of the copies of such reports furnished to us or advice that no filings were required during fiscal year 2005, all executive officers, directors and greater than 10% beneficial owners complied with the Section 16(a) filing requirements.

ITEM 10. EXECUTIVE COMPENSATION

The following table presents the aggregate compensation, which was earned by our Chief Executive Officer for each of the past three years. We do not have an employment contract with any of our executive officers. Jeffrey P. Vickers is our only employee who earned a total annual salary and bonus in excess of $100,000. There has been no compensation awarded to, earned by or paid to any employee required to be reported in any table or column in any fiscal year covered by any table, other than what is set forth in the following table.

Summary Compensation Table

					Long Term Compensation			
	Annual Compensation				Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compen- sation	Restricted Stock Award(s) ($)	Securities Underlying Options SARs(#)	LTIP Payouts ($)	All Other Compen- sation ($)
Jeffrey	2005	$ 88,550	-0-	-0-	N/A	-0-	N/A	$14,800
P.	2004	$ 91,275	-0-	-0-	N/A	-0-	N/A	$12,248
Vickers. CEO	2003	$ 91,700	-0-	-0-	N/A	-0-	N/A	$ 9,250

In the preceding table, the column titled "All Other Compensation" is comprised entirely of profit sharing amounts and the 401(k) Company matching funds discussed below.

If we achieve net income in a fiscal year, our Board of Directors may determine to contribute an amount based on our profits to the Employees' Profit Sharing Plan and Trust (the "Profit Sharing Plan"). An eligible employee may be allocated from 0% to 15% of his other compensation depending upon the total contribution to the Profit Sharing Plan. A total of 20% of the amount allocated to an individual vests after three years of service, 40% after four years, 60% after five years, 80% after six years and 100% after seven or more years. On retirement, an employee is eligible to receive the vested amount. On death, 100% of the amount allocated to an individual is payable to the employee's beneficiary. We made total contributions to the Profit Sharing Plan, matching and discretionary, for the years ended December 31, 2005, 2004 and 2003 of $71,343, $63,421, and $49,593, respectively. As of December 31, 2005, vested amounts in the Profit Sharing Plan for all officers as a group was approximately $585,075.

Effective July 1, 1997, we executed an Adoption Agreement Nonstandardized Code 401(k) Profit Sharing Plan that incorporated a 401(k) Plan into the existing Profit Sharing Plan. This retirement plan was amended and updated to comply with legislative changes effective September 30, 2003. Eligible employees are allowed to defer up to 15% of their compensation and we match up to 5%.

Our 1993 Employees' Incentive Stock Option Plan (the "Plan") expired in 2003. Nonetheless, all options outstanding under that plan remain exercisable until they are cancelled or expire pursuant to their terms.

If within the duration of any outstanding option, there is a corporate merger consolidation, acquisition of assets or other reorganization, and if this transaction affects the optioned stock, the optionee will thereafter be entitled to receive upon exercise of his option those shares or securities that he would have received had the option been exercised prior to the transaction and the optionee had been a stockholder with respect to such shares.

A total of 300,000 shares were reserved for issuance under the Plan. Of the 300,000 reserved shares, options for 110,208 shares remain outstanding at an average exercise price of $2.34. No grants of stock options were made by us during the fiscal year ended December 31, 2005.

Aggregated Option Exercises in Last Fiscal Year and Fiscal Year-End Option Values

The following table summarizes for our Chief Executive Officer (i) the total number of shares received upon exercise of stock options during the fiscal year ended December 31, 2005, (ii) the aggregate dollar value realized upon such exercise, (iii) the total number of unexercised options, if any, held at December 31, 2005, and (iv) the value of unexercised in-the-money options, if any, held at December 31, 2005.

In-the-money options are options where the fair market value of the underlying securities exceeds the exercise or base price of the option. The aggregate value realized upon exercise of a stock option is the difference between the aggregate exercise price of the option and the fair market value of the underlying stock on the date of exercise. The value of unexercised, in-the-money options at fiscal year-end is the difference between the exercise price of the option and the fair market value of the underlying stock on December 31, 2005, which was $8.11 per share. With respect to unexercised, in-the-money options, the underlying options have not been exercised, and actual gains, if any, on exercise will depend on the value of our Common Stock on the date of exercise.

NAME	SHARES ACQUIRED ON EXERCISE(#)	VALUE REALIZED($)	NUMBER OF UNEXERCISED OPTIONS/SARS AT FY-END(#) EXERCISABLE/ UNEXERCISABLE	VALUE OF UNEXERCISED IN-THE-MONEY OPTIONS/SARS AT FY-END EXERCISABLE/ UNEXERCISABLE
Jeffrey P. Vickers, CEO	-0-	-0-	71,000/0	$ 409,700/0

In 2004, the Company adopted the 2004 Employees' Stock Incentive Plan (2004 Plan). The 2004 Plan reserves 300,000 shares of the Company's common stock for either nonstatutory options or incentive stock options that may be granted pursuant to the terms of the 2004 Plan. Under the terms of the 2004 Plan, the option price can not be less than 100% of the fair market value of the Company's common stock on the date of grant, and if the optionee owned more than 10% of the voting stock, the option price per share can not be less than 110% of the fair market value. No options have been granted under the 2004 Plan.

Directors' Compensation

We pay each director who is not also an employee $200 per month, plus $100 per meeting and reimburse the directors for travel expenses. Each director who is also on the audit committee receives an additional $100 per month.

ITEM 11. SECURITIES OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth the number of shares of our Common Stock beneficially owned by each of our officers and directors and by all directors and officers as a group, as of March 15, 2006. Unless otherwise indicated, the shareholders listed in the table have sole voting and investment powers with respect to the shares indicated.

CLASS OF SECURITIES	NAME AND ADDRESS OF BENEFICIAL OWNER	AMOUNT OF SHARES AND NATURE OF BENEFICIAL OWNERSHIP	PERCENT OF CLASS
Common Stock, $.01 par value	Jeffrey P. Vickers 1814 14th Ave. W. Williston, ND 58801	282,634 - Direct and Indirect(a)	7.5%
Common Stock, $.01 par value	Paul A. Krile P. O. Box 329 Sioux Rapids, IA 50585	46,500 - Direct	1.2%
Common Stock, $.01 par value	Cathy Kruse 723 W. 14th St. Williston, ND 58801	9,500 - Direct	(b)
Common Stock, $.01 par value	H. Dennis Hoffelt 9421 E. Desert Lake Sun Lakes, AZ 85248	34,333 - Direct	(b)
Common Stock, $.01 par value	Connie R. Hval 7400 3rd Ave. E. Williston, ND 58801	9,500 - Direct(c)	(b)
Common Stock, $.01 par value	Jeffrey B. Jennings 1410 1st Ave. W. Williston, ND 58801	9,500 - Direct	(b)
Common Stock, $.01 par value	Duane Ashley 910 15th St. W. Williston, ND 58801	--	--
Common Stock, $.01 par value	Nick Voller 222 University Ave. Williston, ND 58801	--	--
Common Stock, $.01 par value	Officers and Directors as a Group- (eight persons)	391,967 - Direct and Indirect	10.4%

(a) Includes 139,634 shares owned directly by Mr. Vickers and 72,000 shares held jointly with his wife, Nancy J. Vickers. Also included are 71,000 shares that may be purchased by Mr. Vickers under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

(b) Less than 1%.

(c) Included are 9,500 shares, which may be purchased by Ms. Hval under presently exercisable stock options granted pursuant to our 1993 Employees' Incentive Stock Option Plan.

ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

There are no transactions or series of similar transactions since the beginning of our last fiscal year or any currently proposed transaction or series of similar transactions to which we were or are to be a party, and which the amount involved exceeds $60,000 and in which any director, executive officer, principal shareholder or any member of their immediate family had or will have a direct or indirect material interest.

PART IV

ITEM 13. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) Documents filed as Part of this Report

(1) Financial Statements and Schedules See "Index to Consolidated Financial Statements" on Page 35. There are no financial statement schedules filed herewith.

(2) Exhibits See "Exhibit Index" on page 62.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

During 2005 and 2004, we paid the following fees to our principal accountants:

	2005	2004
Audit Fees	$ 29,500	$ 25,500
Audit Related Fees	2,339	958
Tax Fees	4,235	4,007
All Other Fees (1)	7,335	3,400
	$ 43,409	$ 33,865

(1) Services relating to review of our Quarterly Reports on Form 10-QSB.

To help assure independence of the independent auditors, our Audit Committee has established a policy whereby all audit, review, attest and non-audit engagements of the principal auditor or other firms must be approved in advance by the Audit Committee; provided, however, that de minimis non-audit services may instead be approved in accordance with applicable Securities and Exchange Commission rules. This policy is set forth in our Audit Committee Charter. Of the fees shown in the table, which were paid to our principal accountants, 100% were approved by the Audit Committee.

GEORESOURCES, INC., AND SUBSIDIARIES
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
ON THE CONSOLIDATED FINANCIAL STATEMENTS

To the Board of Directors and Shareholders
GeoResources, Inc.

We have audited the accompanying balance sheets of GeoResources, Inc. as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2005 and 2004, and the results of its operations and its cash flows for the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles.

/s/ Richey, May & Co., LLP
Englewood, Colorado
March 15, 2006

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2005 AND 2004

ASSETS

	2005	2004
CURRENT ASSETS:		
Cash and equivalents	$ 1,669,882	$ 715,551
Trade receivables, net	1,109,202	1,030,716
Inventories	236,081	235,405
Prepaid expenses	38,738	65,762
Total current assets	3,053,903	2,047,434
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Properties being amortized	27,842,549	25,997,466
Properties not subject to amortization	202,257	213,921
Drilling rig and equipment	1,607,094	1,533,838
Leonardite plant and equipment	854,789	3,284,466
Other	790,100	756,535
	31,296,789	31,786,226
Less accumulated depreciation, depletion, amortization and impairment	(19,650,972)	(21,113,489)
Net property, plant and equipment	11,645,817	10,672,737
TOTAL ASSETS	$ 14,699,720	$ 12,720,171

LIABILITIES AND STOCKHOLDERS' EQUITY

	2005	2004
CURRENT LIABILITIES:		
Accounts payable	$ 1,152,532	$ 996,624
Accrued expenses	293,505	382,693
Income taxes payable	64,000	--
Current portions of capital lease obligations	41,549	64,286
Current maturities of long-term debt	523,941	518,750
Total current liabilities	2,075,527	1,962,353
CAPITAL LEASE OBLIGATIONS, less current portions	13,298	54,847
LONG-TERM DEBT, less current maturities	177,638	1,205,729
ASSET RETIREMENT OBLIGATIONS	2,324,690	1,893,510
DEFERRED INCOME TAXES	753,000	524,000
Total liabilities	5,344,153	5,640,439
CONTINGENCIES (NOTE J)		
STOCKHOLDERS' EQUITY:		
Common stock, par value $.01 per share; authorized 10,000,000 shares; issued and outstanding, 3,765,269 and 3,723,977 shares, respectively	37,653	37,240
Additional paid-in capital	391,881	295,932
Retained earnings	8,926,033	6,746,560
Total stockholders' equity	9,355,567	7,079,732
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 14,699,720	$ 12,720,171

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

	2005	2004	2003
OPERATING REVENUES:			
Oil and gas	$ 5,824,049	$ 4,452,114	$ 3,614,592
Leonardite	810,738	1,290,644	822,219
Drilling	1,359,872	1,077,367	406,141
	7,994,659	6,820,125	4,842,952
OPERATING COSTS AND EXPENSES:			
Oil and gas production	2,303,238	1,922,479	1,786,379
Leonardite operations	907,943	1,168,148	850,373
Drilling costs	1,258,258	1,009,051	369,869
Depreciation, depletion and amortization	786,156	842,658	759,907
Selling, general and administrative	660,204	594,017	537,141
	5,915,799	5,536,353	4,303,669
Operating income	2,078,860	1,283,772	539,283
OTHER INCOME (EXPENSE):			
Interest expense	(87,592)	(91,363)	(84,432)
Interest income	18,649	10,697	8,362
Gain on involuntary conversion of Leonardite facility	497,743	--	--
Other, net	(34,586)	20,027	18,898
	394,214	(60,639)	(57,172)
Income before income taxes	2,473,074	1,223,133	482,111
INCOME TAX EXPENSE	293,601	117,287	12,548
Income before cumulative effect of change in accounting principle	2,179,473	1,105,846	469,563
Cumulative effect on prior years of accounting change, net of tax	--	--	(23,000)
Net income	$ 2,179,473	$ 1,105,846	$ 446,563
EARNINGS PER SHARE:			
Income before cumulative effect of accounting change	$ .58	$ .30	$ .13
Cumulative effect of accounting change	--	--	(.01)
Net income, basic	$ .58	$ .30	$ .12
Income before cumulative effect of accounting change	$ .57	$ .30	$ .13
Cumulative effect of accounting change	--	--	(.01)
Net income, diluted	$ .57	$ .30	$ .12
Weighted average number of shares outstanding	3,744,488	3,723,977	3,748,396
Dilutive potential shares – Stock options	81,942	--	--
Adjusted weighted average shares	3,826,430	3,723,977	3,748,396

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

	Common Stock		Additional Paid-in	Retained	
	Shares	Amount	Capital	Earnings	Total
Balance, December 31, 2002	3,787,477	$ 37,875	$ 384,185	$ 5,194,151	$ 5,616,211
Purchase of common stock	(63,500)	(635)	(88,253)	--	(88,888)
Net income	--	--	--	446,563	446,563
Balance, December 31, 2003	3,723,977	37,240	295,932	5,640,714	5,973,886
Net income	--	--	--	1,105,846	1,105,846
Balance, December 31, 2004	3,723,977	37,240	295,932	6,746,560	7,079,732
Stock options exercised	41,292	413	95,949	--	96,362
Net income	--	--	--	2,179,473	2,179,473
Balance, December 31, 2005	3,765,269	$ 37,653	$ 391,881	$ 8,926,033	$ 9,355,567

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 2,179,473	$ 1,105,846	$ 446,563
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and valuation allowance	786,156	842,658	759,907
Cumulative effect of accounting change	--	--	23,000
Accretion of asset retirement obligations	92,180	84,310	76,200
Deferred income taxes	229,000	118,000	15,000
Gain on involuntary conversion of leonardite facility	(497,743)	--	--
Other	9,675	25,273	8,952
Changes in assets and liabilities:			
Decrease (increase) in:			
Trade receivables	(37,263)	53,962	(263,219)
Inventories	(676)	(2,099)	(25,308)
Income taxes receivable	--	--	50,192
Prepaid expenses and other	27,024	(30,427)	(7,009)
Increase (decrease) in:			
Accounts payable	(125,858)	143,875	29,438
Accrued expenses	(89,188)	(21,792)	69,266
Income taxes payable	64,000	--	--
Cash provided by operating activities	2,636,780	2,319,606	1,182,982
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to property, plant and equipment	(1,397,640)	(1,545,988)	(1,130,897)
Proceeds from insurance claim, net of related costs	669,663	--	--
Proceeds from sale of property, plant and equipment	36,352	15,926	14,472
Cash used in investing activities	(691,625)	(1,530,062)	(1,116,425)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments on long-term capital lease obligations	(64,286)	(47,955)	--
Proceeds from long-term borrowings	10,006	125,000	300,000
Proceeds from stock options exercised	96,362	--	--
Principal payments on long-term debt	(1,032,906)	(479,457)	(263,552)
Cost to purchase common stock	--	--	(88,888)
Debt issue costs	--	(15,000)	--
Cash used in financing activities	(990,824)	(417,412)	(52,440)
INCREASE IN CASH AND EQUIVALENTS	954,331	372,132	14,117
CASH AND EQUIVALENTS, beginning of year	715,551	343,419	329,302
CASH AND EQUIVALENTS, end of year	$ 1,669,882	$ 715,551	$ 343,419

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
YEARS ENDED DECEMBER 31, 2005, 2004 AND 2003

	2005	2004	2003
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash paid (received) for:			
Interest	$ 90,907	$ 87,805	$ 87,477
Income taxes (refunds)	601	(713)	(52,644)

NONCASH INVESTING AND FINANCING ACTIVITIES

During 2004, the Company acquired $167,088 of drilling rig equipment by entering into two capital leases.

The accompanying notes are an integral part of these consolidated financial statements.

GEORESOURCES, INC., AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A. SIGNIFICANT ACCOUNTING POLICIES:

Nature of Operations and Principles of Consolidation

The accompanying consolidated financial statements include the accounts of GeoResources, Inc., its wholly owned subsidiaries, Western Star Drilling Company ("WSDC") and Belmont Natural Resource Company, Inc. ("BNRC"). All material intercompany transactions and balances between the entities have been eliminated.

GeoResources, Inc. (the "Company") is primarily involved in oil and gas exploration, development and production in North Dakota and Montana and the mining of leonardite and manufacturing of leonardite products in North Dakota to be sold to customers located primarily in the Gulf of Mexico coastal areas. The leonardite processing facility was damaged in a fire on May 17, 2005, and has not operated since that date. See Note N. WSDC was incorporated in 2002 and provides contract oil and gas drilling services to the Company and other operators in the Williston Basin area of North Dakota. BNRC was incorporated in 1991 to exploit natural gas opportunities in the Pacific Northwest. All properties of the Company, WSDC, and BNRC are located in the United States.

Reclassifications

Certain accounts in the prior-year financial statements have been reclassified for comparative purposes to conform with the presentation in the current-year financial statements.

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 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. Significant estimates used in preparing these financial statements include the unaudited quantity of oil and gas reserves, which directly affects the computation of depletion of oil and gas properties. It is at least reasonably possible that the estimates used will change within the next year.

Cash Equivalents

For purposes of the statements of cash flows, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. The Company periodically maintains cash balances in financial institutions in excess of FDIC limits. The Company evaluates the credit worthiness of these financial institutions in determining the risk associated with these deposits.

Inventories

Inventories are stated at the lower of cost (first-in, first-out method) or market. The cost of crude oil inventory is comprised of lease operating expense and depreciation, depletion and amortization. The cost of leonardite inventories is comprised of direct mining and processing costs including labor costs, plant operating costs, additives and supplies, and depreciation.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas properties. All costs relating to production activities, including workover costs incurred solely to maintain or increase levels of production from an existing completion interval, are charged to expense as incurred. All costs associated with the acquisition, exploration and development of oil and gas reserves are capitalized. (Such costs include costs of abandoned leaseholds, delay lease rentals, dry hole costs, geological and geophysical costs, certain internal costs associated directly with acquisition, drilling and well equipment inventory, exploration and development activities, estimated dismantlement and abandonment costs, site restoration and environmental exit costs, etc.)

All capitalized costs of oil and gas properties, net of estimated salvage values, plus the estimated future costs to develop proved reserves, are amortized on the unit-of-production method using estimates of proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. The Company's oil and gas depreciation, depletion and amortization rate per equivalent barrel of oil produced was $4.72, $4.68, and $4.12 for 2005, 2004, and 2003, respectively.

In addition, the capitalized costs are subject to a "ceiling test", which basically limits such costs to the aggregate of the "estimated present value," discounted at a 10-percent interest rate, of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties. As a result of this ceiling test, the Company had no write-downs of its oil and gas properties during 2005, 2004 or 2003.

Gains or losses are not recognized upon the sale or other disposition of oil and gas properties, except in extraordinary transactions. Consideration received from the sale or other disposition of oil and gas properties, including from sales or transfers of properties in connection with partnerships, joint venture operations, or other forms of drilling arrangements (e.g., carried interest, turnkey wells, management fees, etc.), is credited to capitalized costs except to the extent that such consideration represents the reimbursement of current expenses.

No income is recognized from the performance of contractual services (e.g. drilling, well service, etc.) related to properties in which the Company holds an ownership or other economic interest. Any such income not recognized is credited to capitalized costs.

The Company leases non-producing acreage for its exploration and development activities. The cost of these leases plus accumulated delay rentals is recorded at the lower of cost or fair market value. It is expected that evaluation of these leases will occur primarily over the next three years. At December 31, 2005, the costs of these unevaluated, undeveloped oil and gas properties, which are not being amortized, were acquired during the following years:

2005	$ 37,848
2004	37,319
2003	34,165
2002	27,689
2001 and prior	65,236
Total	$ 202,257

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Other Property and Equipment

Other property, plant and equipment is stated at cost. Major replacements and improvements are capitalized. Maintenance and repair costs are generally charged to expense as incurred. When assets are sold, retired, or otherwise disposed of, the cost and related accumulated depreciation are eliminated from the accounts and gain or loss is recognized.

Depreciation of the drilling rig and equipment, after a 20% provision for salvage value, is computed on a composite basis for the total rig investment using the units-of-production method over an estimated useful life of 1,500 drilling days as of the in-service date or date of major refurbishment. Depreciation of the leonardite plant and equipment is computed using the straight-line method over estimated useful lives of 3 to 25 years. See Note N. Depreciation of other property and equipment is computed principally on the straight-line method over the following estimated useful lives:

Office building	20 years
Office furniture and equipment	3-7 years
Reymert property	15 years

Impairment of Long-Lived Assets

Potential impairment of long-lived assets (other than oil and gas properties) is reviewed whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. Impairment is recognized when the estimated future net cash flows (undiscounted and without interest charges) from the asset are less than the carrying amount of the asset. No impairment losses have been recognized on long-lived assets.

Asset Retirement Obligations

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 tangible 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. The Company has also identified other asset retirement obligations that are not recorded because a reasonable estimate of the fair value cannot be made due to the indeterminate life of the associated assets. There are no assets legally restricted for the purpose of settling asset retirement obligations.

Revenue Recognition

Revenue from the sale of oil and gas production, net of royalties, is recognized when deliveries occur. Revenue from the sale of leonardite products is recognized when shipments are made. Drilling revenue from daywork contracts is recognized as the work progresses. WSDC has not engaged in any footage or turnkey drilling contracts.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

Operating Costs and Expenses

Oil and gas production costs, the cost of leonardite operations, and drilling costs exclude a provision for depreciation and depletion. Depreciation and depletion expense is shown in the aggregate in the accompanying consolidated statements of operations.

Income Taxes

Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes on temporary differences between the amount of taxable income and pretax financial income and between the tax bases of assets and liabilities and their reported amounts in the financial statements. 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. A valuation allowance is provided for deferred tax assets not expected to be realized.

Stock Options

The Company accounts for stock options under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees", and related interpretations. The effect on net income or earnings per share if the Company had applied the fair value recognition provisions of FASB Statement No. 123, "Accounting for Stock-Based Compensation", to stock-based employee compensation has not been presented as no options were granted and therefore there is no effect for the years ended December 31, 2005, 2004, and 2003.

Earnings Per Share of Common Stock

Basic earnings per share is determined using net income divided by the weighted average shares outstanding during the period. Diluted earnings per share is computed by dividing net income by the weighted average shares outstanding, assuming all dilutive potential common shares were issued. The effect of outstanding stock options was antidilutive in 2004 and 2003.

Recently Issued Accounting Pronouncements

In November 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard ("SFAS") No. 151, "Inventory Costs, an Amendment of ARB No. 43, Chapter 4". The statement requires abnormal amounts of freight, handling costs, idle facility expense and spoilage to be recognized as current period expenses. This statement became effective for the Company on January 1, 2006. The adoption of this statement is not expected to have a significant impact on the Company's results of operations, financial position or cash flows.

In December 2004, the FASB issued SFAS No. 123R, "Share-Based Payment". This statement replaces SFAS No. 123, "Accounting for Stock Based Compensation" and supersedes ABP Opinion No. 25, "Accounting for Stock Issued to Employees". It establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation, eliminating the alternative to use APB No. 25's intrinsic value method. The statement became effective for the Company on January 1, 2006. In March 2005, the SEC released Staff Accounting Bulletin No. 107 "Share-Based Payment", which provides interpretive guidance related to the interaction between SFAS 123 (R) and certain SEC rules and regulations. It also provides the SEC staff's views regarding valuation of share-based payment arrangements. Management believes that SFAS No. 123 (R) and SAB No. 107 will have an impact on future share-based transactions of the Company but cannot determine the impact at this time.

A. SIGNIFICANT ACCOUNTING POLICIES (Continued):

In December 2004, the FASB issued SFAS No. 153, "Exchanges of Nonmonetary Assets, and Amendment of APB No. 29". This statement amends and clarifies financial accounting for nonmonetary exchanges by requiring that most exchanges of productive assets be accounted for at fair value. With certain exceptions, companies can no longer account for nonmonetary exchanges at book value with no gain or loss recognized. This statement became effective for the Company on January 1, 2006, and may impact the Company's consolidated financial position and results of operations in future periods if such nonmonetary exchanges occur.

In March 2005, the FASB issued Interpretation No. 47 (FIN 47), "Accounting for Conditional Asset Retirement Obligations", an Interpretation of FASB Statement No. 143, which clarifies the accounting for conditional asset retirement obligations as used in SFAS No. 143, "Accounting for Asset Retirement Obligations". A conditional asset retirement obligation is an unconditional legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Under FIN 47, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligations if the fair value of the liability can be reasonably estimated. Any uncertainty about the amount and/or timing of future settlement should be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value. The provisions of FIN 47 are effective for years ending after December 31, 2005. The Company is currently evaluating the impact of FIN 47 on its consolidated financial statements.

In May 2005, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections", a replacement of APB Opinion No. 20 and FASB Statement No. 3. This Statement provides guidance on accounting for reporting of accounting changes and error corrections. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The Company does not expect the impact of adopting SFAS No. 154 to have a material effect on its consolidated results of operations or financial position.

B. INDUSTRY SEGMENTS:

The Company assesses performance and allocates resources based upon its products and the nature of its production processes, which consist principally of a) oil and gas exploration, development and production; b) oil and gas drilling; and c) mining of leonardite (oxidized lignite coal) and manufacturing of leonardite based products, which are sold primarily as oil and gas drilling mud additives. All operations are conducted within the United States. Operations of the drilling segment commenced in January 2002. Sales and other material transactions between the segments have been eliminated. Operations of the leonardite segment became idle in May 2005. See Note N. Certain corporate costs, assets and capital expenditures that are considered to benefit the entire organization are not allocated to the Company's operating segments. Interest income, interest expense and income taxes are also not allocated to operating segments. There are no significant accounting differences between internal segment reporting and consolidated external reporting. Presented below is information concerning the Company's operating segments for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Revenue:			
Oil and gas	$ 5,824,049	$ 4,452,114	$ 3,614,592
Leonardite	810,738	1,290,644	822,219
Drilling	1,359,872	1,077,367	406,141
	$ 7,994,659	$ 6,820,125	$ 4,842,952
Operating income (loss):			
Oil and gas	$ 2,964,640	$ 1,949,529	$ 1,262,129
Leonardite	(165,567)	(10,542)	(150,146)
Drilling	(50,233)	(60,019)	(22,861)
General corporate	(669,980)	(595,196)	(549,839)
	$ 2,078,860	$ 1,283,772	$ 539,283
Depreciation and depletion:			
Oil and gas	$ 556,171	$ 580,106	$ 566,084
Leonardite	43,882	99,412	99,478
Drilling	151,847	128,335	59,133
General corporate	34,256	34,805	35,212
	$ 786,156	$ 842,658	$ 759,907
Identifiable assets, net:			
Oil and gas	$ 10,759,625	$ 9,237,435	$ 8,576,643
Leonardite	395,422	820,742	848,705
Drilling	1,521,874	1,546,104	1,362,538
General corporate	2,022,799	1,115,890	796,387
	$ 14,699,720	$ 12,720,171	$ 11,584,273
Capital expenditures incurred:			
Oil and gas	$ 1,809,003	$ 1,222,757	$ 1,379,720
Leonardite	81,204	56,115	16,668
Drilling	84,942	378,542	99,388
General corporate	19,441	--	2,166
	$ 1,994,590	$ 1,657,414	$ 1,497,942

C. TRADE RECEIVABLES AND MAJOR CUSTOMERS:

Trade receivables at December 31, 2005 and 2004 are comprised of the following:

	2005	2004
Oil and gas purchasers	$ 739,241	$ 516,558
Oil and gas joint interest owners	36,796	59,033
Leonardite customers	55,084	233,475
Drilling customers	278,081	221,650
	$ 1,109,202	$ 1,030,716

The Company is subject to credit risk associated with the purchasers of its produced oil and gas products, leonardite products and drilling services. Exposure to this credit risk is controlled through credit approvals and monitoring procedures. Collateral is not required. Receivables from joint interest owners are subject to collection under operating agreements that generally provide lien rights.

The Company primarily sells crude oil. The Company's production of crude oil is concentrated in the Williston Basin of North Dakota, which is a mature basin. In addition, 32% and 10% of the Company's 2005 oil and gas production was from the Wayne Field and Leonard Field, respectively. Due to the significance of these fields, disruptions could adversely affect the Company.

The Company had major customers that purchased oil and gas products as follows:

	Customer	
	A	B
Percent of total revenue for the years ended-		
December 31, 2005	27%	35%
December 31, 2004	26%	31%
December 31, 2003	28%	36%
Percent of total accounts receivable as of-		
December 31, 2005	25%	33%
December 31, 2004	23%	25%

Management believes that other purchasers would buy the Company's oil and gas if any of its customers were lost.

D. INVENTORIES:

As of December 31, 2005 and 2004, inventories by major classes are comprised of the following. See Note N regarding the status of leonardite inventories.

	2005	2004
Crude oil	$ 113,648	$ 80,568
Leonardite inventories:		
Finished products	11,233	34,416
Raw materials	11,494	42,860
Materials and supplies	99,706	77,561
Total leonardite inventories	122,433	154,837
	$ 236,081	$ 235,405

E. CAPITAL LEASE OBLIGATIONS:

The Company leases equipment with a capitalized cost of $167,088 and a book value of $106,013 under a capital lease expiring March 2007. The lease agreement calls for monthly payments of $3,650 with interest imputed at 6.25% per annum. Following is a schedule of the future minimum lease payments together with the present value of the net minimum lease payments as of December 31, 2005:

Year Ending December 31:	Amount
2006	$ 43,800
2007	13,450
	57,250
Less amount representing interest	(2,403)
	54,847
Less current portion	(41,549)
Long-term portion	$ 13,298

F. LONG-TERM DEBT:

Long-term debt at December 31, 2005 and 2004 consists of the following. The oil and gas loan and the revolving line of credit (RLOC) are with the same bank.

	2005	2004
The 2001 Oil & Gas loan, interest at prime (7.25% rate at December 31, 2005), due in monthly installments of $43,229 plus interest through January 2008, collateralized by oil and gas properties	$ 696,388	$ 1,599,479
The 2004 Oil and Gas RLOC, $3,000,000 revolving line of credit expires March 5, 2007, interest only payable at prime through March 2007 (7.25% rate at December 31, 2005), principal and interest payable thereafter through March 2011, collateralized by oil and gas properties.	--	125,000
Installment note payable, 15.74%, collateralized by a vehicle	5,191	--
Total long-term debt	701,579	1,724,479
Less current maturities	(523,941)	(518,750)
Long-term debt, less current maturities	$ 177,638	$ 1,205,729

Aggregate maturities required on long-term debt at December 31, 2005, are as follows:

Year Ending December 31:	
2006	$ 523,941
2007	177,638
	$ 701,579

The Company's borrowing base for debt secured by oil and gas properties is limited by the net present value of future oil and gas production of the properties as determined annually by the bank.

The Company's Oil and Gas Loan and 2004 RLOC were obtained pursuant to financing agreements, which include the following covenants: Maintain a debt service coverage ratio of not less than 1.25 to 1; not encumber certain of its assets; restrict borrowings from, and credit extensions to, other parties; restrict reorganization or mergers in which the Company is not the surviving corporation; and not pay cash dividends without the bank's consent.

G. ASSET RETIREMENT OBLIGATIONS:

Effective January 1, 2003, the Company adopted SFAS 143, "Accounting for Asset Retirement Obligations", which requires that the fair value of a liability for an asset retirement obligation associated with a tangible long-lived asset be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. The asset retirement obligations recorded by the Company relate to the future plugging and abandonment costs of its oil and gas wells.

A liability is incurred in the period in which an oil or gas well is acquired or drilled. The fair value of the liability is estimated based on historical experience in plugging and abandoning wells, federal and state regulatory requirements, estimated useful lives of wells based on engineering studies, estimates of the cost to plug and abandon wells in the future, and the Company's credit-adjusted risk-free interest rate. Revisions of the liability occur due to changes of those factors. Each period the liability is accreted to its future estimated value until the liability is settled. Settlement of the liability occurs when a well is sold or plugged and abandoned. Accretion expense is included in oil and gas production expense on the Company's consolidated statements of operations.

Prior to adoption of SFAS No. 143, the Company assumed that the salvage value of oil and gas well equipment equaled the plugging and abandonment costs. Therefore, no liabilities for retirement obligations were recorded. The initial adoption of SFAS No. 143 on January 1, 2003, resulted in a one-time non-cash after-tax charge to operations of $23,000 recorded as the cumulative effect of a change in accounting principle. The adoption also resulted in an increase to oil and gas properties being amortized of $1,562,000, a discounted liability for asset retirement obligations of $1,589,000, and a decrease of deferred income tax liabilities of $4,000. There was no impact on the Company's cash flows as a result of adopting SFAS No. 143.

Changes in asset retirement obligations for the years ended December 31, 2005 and 2004, were as follows. The 2005 revisions are primarily related to estimated longer productive lives of wells due to higher oil and gas prices.

	2005	2004
Beginning of year	$ 1,893,510	$ 1,735,200
Liabilities incurred	14,000	19,000
Revisions to estimate	327,000	58,000
Accretion expense	92,180	84,310
Liabilities settled	(2,000)	(3,000)
End of year	$ 2,324,690	$ 1,893,510

Pro forma net income for the year ended December 31, 2003, assuming retroactive application of SFAS No. 143 is as follows:

	2003
Net income	$ 469,563
Net income per share, basic and diluted	$ .13

H. INCOME TAXES:

The tax effects of significant temporary differences and carryforwards, which give rise to the Company's deferred tax assets and liabilities at December 31, 2005 and 2004, are as follows:

	2005	2004
Deferred Tax Assets:		
Net operating loss carryforward	$ --	$ 193,000
Statutory depletion carryforward	2,131,000	1,852,000
Other	18,000	69,000
	2,149,000	2,114,000
Valuation Allowance:		
Beginning of year	(880,000)	(929,000)
(Increase) decrease	154,000	49,000
End of year	(726,000)	(880,000)
Deferred Tax Liabilities:		
Property, plant and equipment	(2,176,000)	(1,758,000)
Net Deferred Tax Liability, long-term	$ (753,000)	$ (524,000)

The components of income tax expense for the years ended December 31, 2005, 2004 and 2003, are as follows:

	2005	2004	2003
Current tax benefit (expense)	$ (64,601)	$ 713	$ 2,452
Deferred tax (expense)	(383,000)	(167,000)	(4,000)
Decrease (increase) in deferred tax assets valuation allowance	154,000	49,000	(11,000)
Income tax (expense)	$ (293,601)	$ (117,287)	$ (12,548)

During 2003, the Company recorded deferred tax expense of only $4,000 since the benefit of the net operating loss and depletion carryforwards generated was offset by property, plant and equipment timing differences. During 2004 and 2005, the Company recorded deferred tax expense primarily due to the utilization of net operating loss carryforwards resulting in no currently payable federal taxes in 2004 and currently payable taxes of only $64,601 in 2005. After 2005, the Company has no remaining net operating loss carryforwards. The change in the deferred tax assets valuation allowance in each year relates to a projection of the future utilization of statutory depletion carryforwards.

H. INCOME TAXES (Continued):

The provision for income taxes does not bear a normal relationship to pre-tax earnings. A reconciliation of the U.S. federal income tax rate with the actual effective rate for the years ended December 31, 2005, 2004 and 2003, is as follows:

	2005	2004	2003
Income tax expense at statutory rate	35%	35%	35%
State income taxes	7	7	7
Effect of graduated rates	(11)	(14)	(14)
Statutory depletion	(11)	(15)	(32)
Change in valuation allowance	(6)	(4)	2
Other	(2)	1	5
	12%	10%	3%

For income tax purposes, the Company has a statutory depletion carryover of approximately $7,100,000 that, subject to certain limitations, may be utilized to reduce future taxable income. This carryforward does not expire.

I. STOCK OPTION AND PROFIT-SHARING PLANS:

Stock Option Plans
The Company's 1993 Incentive Stock Option Plan expired February 17, 2003.

In 2004, the Company adopted the 2004 Employees' Stock Incentive Plan (2004 Plan). The 2004 Plan reserves 300,000 shares of the Company's common stock for either nonstatutory options or incentive stock options that may be granted pursuant to the terms of the 2004 Plan. Under the terms of the 2004 Plan, the option price can not be less than 100% of the fair market value of the Company's common stock on the date of grant, and if the optionee owned more than 10% of the voting stock, the option price per share can not be less than 110% of the fair market value.

No options have been granted under the 2004 Plan. Information with respect to the 1993 plan's activity is as follows:

	Shares Available for Options	Shares Subject to Outstanding Options
December 31, 2002	100,500	175,500
Cancelled	(100,500)	--
Exercised	--	--
December 31, 2003	--	175,500
Cancelled	--	(9,500)
Exercised	--	--
December 31, 2004	--	166,000
Cancelled	--	(14,500)
Exercised	--	(41,292)
December 31, 2005	--	110,208

Information with respect to the options outstanding and exercisable at December 31, 2005, is as follows:

Number of shares	Exercise Price	Expiration Date
56,208	$ 2.37	May 2007
54,000	$ 2.31	December 2007
110,208		

The average exercise price is $2.34 for options outstanding and exercisable at December 31, 2005.

I. STOCK OPTION AND PROFIT-SHARING PLANS (Continued):

Profit-Sharing Plan

The Company has a 401(k) profit sharing plan that covers all employees with one year of service who elect to enter the plan. The plan provides for employee contributions subject to IRS and plan limitations. The Company contributes an amount equal to each employee's contribution up to a maximum of 5% of the employee's compensation. The Company may also make additional discretionary contributions to the plan. The Company's total contributions to the plan, matching and discretionary, for the years ended December 31, 2005, 2004 and 2003 were $71,343, $63,421 and $49,593, respectively.

J. CONTINGENCIES:

The Company is a defendant in a bankruptcy case with respect to a preference claim brought on November 8, 2002, in the United States Bankruptcy Court, Southern District of Texas, Houston Division (adversary proceeding number 02-03827, In Re: Ramba, Inc., Lowell T. Cage, Trustee v. GeoResources, Inc.). The bankruptcy trustee of a former leonardite customer, Ambar, Inc. (n/k/a Ramba, Inc.) has sued the Company for approximately $139,000 in an amended preference claim in Bankruptcy Court. The defense has been vigorous, and on September 1, 2004, the District Court granted the Company's motion for summary judgment. The plaintiff perfected an appeal to the Fifth circuit, which ruled in favor of the Company except for $28,400. At an April 7, 2006, hearing with the Judge and the Plaintiff, our attorneys plan to explore the possibility of a settlement. As of December 31, 2005 and 2004, the Company has recorded a reserve of $20,000 and $50,000, respectively, with respect to this matter.

All of the Company's operations are generally subject to federal, state or local environmental regulations. The Company's oil and gas business segment is affected particularly by those environmental regulations concerned with the disposal of produced oilfield brines and other wastes. The Company's leonardite mining and processing segment is subject to numerous state and federal environmental regulations, particularly those concerned with air quality at the Company's processing plant, and surface mining permit and reclamation regulations. The amount of future environmental compliance costs cannot be determined at this time.

K. OFFICE FACILITIES:

In 1991, the Company purchased an office building, one-half of which it occupies. The building is included in other property and equipment in the accompanying consolidated balance sheets and consists of the following at December 31, 2005 and 2004:

	2005	2004
Building and improvements	$ 163,834	$ 163,834
Accumulated depreciation	(121,092)	(112,901)
	$ 42,742	$ 50,933

The Company leases the remainder of the building to unaffiliated businesses under cancelable lease agreements. During 2005, 2004 and 2003, the Company received $19,800 each year, of rental income from the building that is included in other income in the accompanying statements of operations.

L. FINANCIAL INSTRUMENTS:

The carrying amounts reflected in the consolidated balance sheets for cash and equivalents, short-term receivables and short-term payables approximate their fair value due to the short maturity of the instruments. The carrying value of long-term debt approximates fair value based on the variable nature of the interest rates.

M. RELATED PARTY TRANSACTIONS:

During 2003, WSDC incurred rent expense of $3,500, paid to its President under a month-to-month lease for office space.

N. LEONARDITE PROCESSING FACILITY FIRE:

Our leonardite processing facility was damaged in a fire on May 17, 2005, and has not operated since that date. Our insurance carrier determined the scope of damage and paid us $694,141 during 2005. We have recognized an additional insurance claim receivable of $41,223 as of December 31, 2005. We recorded a gain from this involuntary conversion of $497,743 consisting of the insurance claim proceeds less the net book value of the facility at the time of the fire and less direct costs incurred because of the fire. During 2005 we also incurred $51,764 of uninsured labor and other costs related to post fire clean up and minor repairs. These costs are included in other non-operating expense.

The fire has not affected our mining of leonardite raw material; however, other assets undamaged by the fire are temporarily idle pending either the resumption of operations at the processing facility, the employment of those assets in an alternative use, or their sale or other disposition. No depreciation expense has been recorded on these idle assets since May 2005. The net book value of temporarily idle assets, which consists of property, equipment, and inventory, as of December 31, 2005, is $215,200.

Although we are continuing to explore any strategic alternatives for our leonardite-operating segment, we currently are expecting to restore our leonardite facility to operations, and we have given our insurance carrier written notice of that intention. It is uncertain at this time when repairs will begin, because the scope of the repairs has not been fully determined due to engineering and design work that have not been completed and labor concerns caused by oil and gas activity in the Williston, North Dakota, area. For the present time, we intend to keep all of our options open by continuing to pursue minor raw material sales, engineering design and specification for needed equipment replacement, and any other strategic alternatives that make the best use of our assets. If construction activity begins in a reasonable amount of time, we will be able to draw on additional insurance proceeds of up to approximately $640,000 as repairs are made.

O. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES:

Net capitalized costs related to the Company's oil and gas producing activities are summarized as follows as of December 31, 2005, 2004 and 2003:

	2005	2004	2003
Proved properties	$ 27,842,549	$ 25,997,466	$ 24,711,298
Unproved properties	202,257	213,921	280,565
Total	28,044,806	26,211,387	24,991,863
Less accumulated depreciation, depletion, amortization and impairment	(18,179,866)	(17,623,695)	(17,043,589)
Net capitalized costs	$ 9,864,940	$ 8,587,692	$ 7,948,274

Costs incurred in oil and gas property acquisition, exploration and development activities, including capital expenditures are summarized as follows for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Property acquisition costs:			
Proved	$ 26,303	$ 48,159	$ 25,674
Unproved	34,226	38,762	32,358
Exploration costs	261,241	220,423	231,355
Development costs	1,487,233	915,413	1,090,333
	$ 1,809,003	$ 1,222,757	$ 1,379,720

The Company's results of operations from oil and gas producing activities (excluding corporate overhead and financing costs) are presented below for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Oil and gas sales	$ 5,824,049	$ 4,452,114	$ 3,614,592
Production costs	(2,303,238)	(1,922,479)	(1,786,379)
Depletion, depreciation and amortization	(556,171)	(580,106)	(566,084)
	2,964,640	1,949,529	1,262,129
Statutory income tax provision	(468,761)	(49,808)	--
	$ 2,495,879	$ 1,899,721	$ 1,262,129

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

The reserve information presented below is based upon reports prepared by the independent petroleum-engineering firms of Sproule Associates Inc. and Broschat Engineering and Management Services. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of mature producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

O. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited) (Continued)

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 years from known reservoirs under economic and operating conditions existing as of the end of each respective year. The year-end selling price of oil and gas is one of the primary factors affecting the determination of proved reserve quantities, which fluctuate directly with that price.

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, 2005, 2004 and 2003:

	2005		2004		2003	
	Oil (bbl)	Gas (mcf)	Oil (bbl)	Gas (mcf)	Oil (bbl)	Gas (mcf)
Proved reserves, beginning of year	2,342,000	391,000	2,458,000	387,000	2,487,000	421,000
Purchases of reserves-in-place	--	--	10,000	--	--	--
Sales of reserves-in-place	--	--	--	--	--	--
Extensions and discoveries	100,000	110,000	22,000	--	34,000	--
Improved recovery	--	--	--	--	--	--
Revisions of previous estimates	490,000	902,000	(25,000)	10,000	73,000	(26,000)
Production	(120,000)	(7,000)	(123,000)	(6,000)	(136,000)	(8,000)
Proved reserves, end of year	2,812,000	1,396,000	2,342,000	391,000	2,458,000	387,000

Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved developed reserves of the Company are presented below as of December 31:

	Oil (bbl)	Gas (mcf)
2005	2,070,000	1,396,000
2004	1,652,000	391,000
2003	1,636,000	387,000

O. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Standardized Measure of Proved Oil and Gas Reserves (Unaudited)

Statement of Financial Accounting Standards No. 69 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Company has followed these guidelines, which are briefly discussed below. Future cash inflows and future production and development costs are determined by applying year-end selling prices and year-end production and development costs to the estimated quantities of oil and gas to be produced. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates are the basis for the valuation process. Estimated future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion, depletion carryforwards, net operating loss carryforwards, and investment tax credit carryforwards. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect the Company's expectations of actual revenues or future net cash flows to be derived from those reserves nor their present worth.

Presented below is the standardized measure of discounted future net cash flows as of December 31, 2005, 2004 and 2003.

	2005	2004	2003
Future cash inflows	$ 140,161,000	$ 81,996,000	$ 70,919,000
Future production costs	(43,993,000)	(30,821,000)	(28,371,000)
Future development costs	(7,656,000)	(5,564,000)	(5,267,000)
Future income tax expense	(25,565,000)	(12,564,000)	(9,748,000)
Future net cash flows	62,947,000	33,047,000	27,533,000
Less effect of a 10% discount factor	(32,191,000)	(13,771,000)	(11,966,000)
Standardized measure of discounted future net cash flows relating to proved reserves	$ 30,756,000	$ 19,276,000	$ 15,567,000

O. OIL AND GAS PRODUCING ACTIVITIES AND PROPERTIES (Continued):

Standardized Measure of Proved Oil and Gas Reserves (Unaudited) (Continued)
The principal sources of change in the standardized measure of discounted future net cash flows are as follows for the years ended December 31, 2005, 2004 and 2003:

	2005	2004	2003
Standardized measure, beginning of year	$ 19,276,000	$ 15,567,000	$ 14,458,000
Sales of oil and gas produced, net of production costs	(3,521,000)	(2,530,000)	(1,828,000)
Net changes in prices and production costs	6,384,000	6,504,000	1,690,000
Purchases of reserves-in-place	--	77,000	--
Sales of reserves-in-place	--	--	--
Extensions, discoveries and other additions, less related costs	1,914,000	270,000	325,000
Revisions of previous quantity estimates and other	10,263,000	(285,000)	594,000
Development costs incurred during the year and changes in estimated future development costs	(924,000)	(504,000)	(360,000)
Accretion of discount	2,527,000	1,994,000	853,000
Net change in income taxes	(5,163,000)	(1,817,000)	(165,000)
Standardized measure, end of year	$ 30,756,000	$ 19,276,000	$ 15,567,000

SHAREHOLDER INFORMATION

OFFICERS & DIRECTORS

J.P. Vickers
Director & President
Williston, North Dakota

Jeffrey B. Jennings
Vice President, Land & Finance
Williston, North Dakota

Cathy Kruse
Director & Secretary
Williston, North Dakota

Connie R. Hval
Treasurer
Williston, North Dakota

H. Dennis Hoffelt
Director, Audit Committee
Williston, North Dakota

Paul A. Krile
Director, Audit Committee
President & Owner
Ranco Fertiservice
Sioux Rapids, Iowa

Nick Voller
Director, Audit Committee
Certified Public Accountant
Williston, North Dakota

Duane Ashley
Director
Senior Salesman
Graco Fishing and Rental Tools, Inc.
Williston, North Dakota

LEGAL COUNSEL

Jones & Keller
Denver, Colorado

AUDITORS

Richey, May & Co., LLP
Englewood, Colorado

CORPORATE OFFICE

1407 West Dakota Parkway, Suite 1-B
P.O. Box 1505
Williston, North Dakota 58802-1505
Phone (701) 572-2020
Fax (701) 572-0277
E-mail ir@geoi.net
www.geoi.net

TRANSFER AGENT

For information regarding change of address or other information regarding your stockholder account, please contact our transfer agent directly:
Wells Fargo Bank, N.A.
Shareowner Services
P.O. Box 64854
St. Paul, Minnesota 55164-0854
(800) 468-9716
www.wellsfargo.com/com/shareowner_services

STOCK TRADED

Our Common Stock trades on the Nasdaq SmallCap Market tier of the Nasdaq Stock Market under the symbol GEOI.

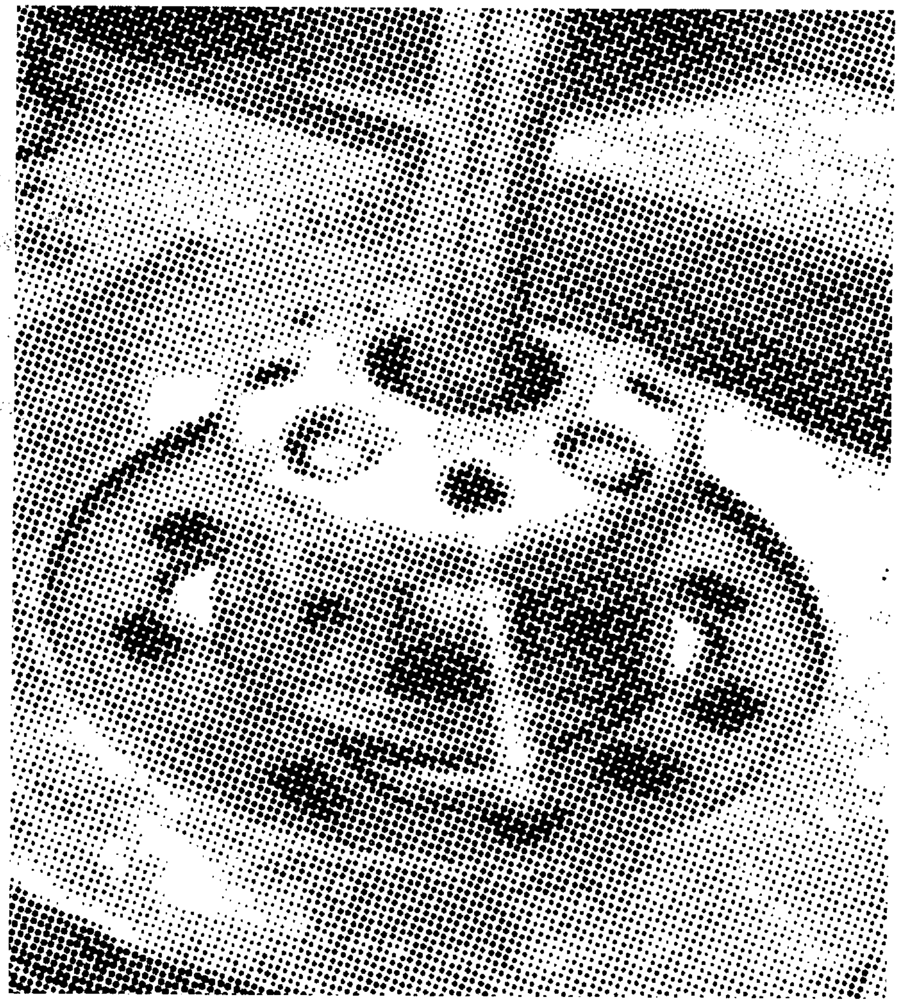
SECURITY MARKET MAKERS

The following investment securities firms made a market in our Common Stock during 2005:

Archipelago, L.L.C., Chicago, IL
Bear, Stearns and Co., Inc., New York, NY
Boston Stock Exchange, Boston, MA
Domestic Securities, Seattle, WA
GVR Company LLC, Chicago, IL
Hill, Thompson, Magid and Co., Jersey City, NJ
Hudson Securities, Inc., Jersey City, NJ
Knight Securities L.P., New York, NY
National Stock Exchange, Cincinnati, OH
Oppenheimer & Co., Inc., New York, NY
SouthWest Securities, Inc., New York, NY
TD Waterhouse, New York, NY
The Brut ECN, LLC, Ridgefield, NJ
Wm. V. Frankel & Co., Inc., Jersey City, NJ

FORWARD-LOOKING INFORMATION

Information herein contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by words such as "may," "expect," "anticipate," "estimate," or "continue," or comparable words. In addition, all statements other than statements of historical facts that address activities that the Company expects or anticipates will or may occur in the future are forward-looking statements. Readers are encouraged to read the SEC reports of the Company, particularly its Form 10-KSB for the Fiscal Year Ended December 31, 2005, for meaningful cautionary language disclosure.



GEOI INC.

2005 Annual Report

GeoResources, Inc.
1407 West Dakota Parkway
Suite 1-B
P.O. Box 1505
Williston, North Dakota 58802-1505
(701) 572-2020
www.geoi.net