U. S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form ~~10-KSB~~ AR/S

[X] ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ____________ to ____________
Commission file number 000-32325

GMX RESOURCES INC.

(Name of small business issuer in its charter)

Oklahoma	**73-1534474**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)

9400 North Broadway, Suite 600, Oklahoma City, Oklahoma 73114
(Address of principal executive offices)

(Issuer's Telephone Number) **(405) 600-0711**

Securities registered under Section 12(b) of the Exchange Act: **None**

Securities registered under Section 12(g) of the Exchange Act: **Name of each exchange on which registered**

Title of each class	
Common Stock, $0.001 par value	**NASDAQ National Market System**
Class A Warrants	**NASDAQ National Market System**

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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. [X] Yes [ ] No

Check if there is no disclosure of delinquent filers in response to Item 405 of Regulation S-B 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. [ ]

The issuer's revenue for the year ended December 31, 2004 was $7,833,710.

The aggregate market value of the voting and non-voting common equity (excluding warrants) held by non-affiliates on March 23, 2005 was $91.9 million. This amount was computed using closing price of the issuer's common stock on March 22, 2005 on the NASDAQ National Market.

As of March 22, 2005, the issuer had outstanding a total of 8,201,587 shares of its $0.001 par value Common Stock.

***Documents* incorporated by reference** - None

Transitional Small Business Disclosure Format (Check one): Yes [ ] No [X]

GMX RESOURCES INC.
Form 10-KSB
Table of Contents

PART I

Item 1. BUSINESS

General

GMX Resources Inc. (referred to herein as "we," "us," "GMX" or the "Company") is an independent natural gas producer headquartered in Oklahoma City, Oklahoma. As of December 31, 2004, our principal drilling and development activities were focused on our property base in the East Texas, North Carthage Field in Harrison and Panola counties, which we are drilling in a joint development agreement with Penn Virginia Oil & Gas, L.P. ("PVOG"), a wholly owned subsidiary of Penn Virginia Corporation (NYSE: PVA). As of December 31, 2004, we had proved reserves of 64.3 Bcfe and 66 gross (44.3 net) producing wells. In the North Carthage Field, we also held a large inventory of Cotton Valley Sand development prospects, including 67 gross (39 net) proved undeveloped locations and an additional 113 gross (74 net) probable and 275 gross (150 net) possible drilling locations depending on the area of well spacing. Our strategy is to significantly grow production and natural gas reserves and build shareholder value.

General Development of Our Business

Organization

At the time of our organization in 1998, we acquired from an unrelated third party for $6.0 million, producing and undeveloped properties located primarily in East Texas and northwestern Louisiana, Kansas and southeastern New Mexico. When we acquired them, the properties consisted of 71.1 net producing wells, 20,829 net developed and 317 net undeveloped acres. At the acquisition date, the properties had estimated proved developed producing reserves of 5 Bcfe. These properties were acquired out of a bankruptcy reorganization of a small, privately held company. We believed the properties had not been developed to their full potential as a result of the financial condition and lack of technical geological expertise of the prior owner. However, there was substantial high quality geological and engineering data available for the properties, waiting to be evaluated.

2001 Equity Offerings and Drilling

In February 2001, we completed an initial public offering of 1,250,000 units at $8.00 per unit. Each unit consisted of one share of common stock, one Class A warrant to purchase one share of common stock and one Class B warrant to purchase one share of common stock. The Class B warrants expired unexercised. The Class A Warrants are exercisable for $12 per share of common stock and expire on February 12, 2006. The net proceeds of the offering of approximately $8.5 million were used primarily for development drilling in 2001.

In July 2001, we completed a secondary public offering of 2,300,000 shares of common stock at an offering price of $5.50 per share. The proceeds of the offering, net of underwriters' fees and other expenses, were approximately $11.3 million, and were used primarily for the development drilling of oil and gas wells in 2001 and early 2002.

In 2001, we drilled and completed 10 gross (10 net) new gas wells in our East Texas properties.

Drilling Contract

In May 2001, we entered into a drilling contract with Nabors Drilling USA, LP ("Nabors"), obligating us to use two 10,000-foot drilling rigs and crews on a continuous basis for a period of two years at a cost of $14,000 per day per rig. Our payment obligations were secured by standby letters of credit in the aggregate amount of $1,000,000, $500,000 per rig.

In December 2001, we terminated the contract and filed a lawsuit in the United States District Court for the Western District of Oklahoma against Nabors alleging that Nabors made misrepresentations intended to induce us to enter into the drilling contracts as well as alleging that Nabors breached those contracts by providing substandard drilling services. Nabors drew the full $1,000,000 on the letters of credit and counterclaimed for approximately $10,000,000 alleged to be owed for an early termination fee and unpaid invoices. In December 2002, we received a jury verdict in our favor. In May 2003, we settled the lawsuit with no monetary consequences to either party.

2002 and 2003 Activities

Due to liquidity issues from the uncertainties associated with the Nabors litigation, as well as technical defaults under our credit facility, we curtailed all drilling and development activities in 2002 and 2003 and implemented a number of actions to reduce overhead costs. In addition, in 2002, we completed the sale of all of our oil and gas properties in Kansas which had proved reserves of 9,571 Mmcfe and applied substantially all of the $3.6 million in net proceeds to our bank debt. We also pursued a possible sale of our East Texas properties but suspended this process after our success in the trial court in the Nabors litigation.

2003 Year End and 2004 Developments

During the fourth quarter of 2003, we were able to successfully find an industry partner to assist us in developing our East Texas properties.

In December 2003, we executed a definitive participation agreement with PVOG for the joint development of our Cotton Valley, Travis Peak and Pettit prospects located in East Texas. We also entered into several amendments to the agreement in 2004. This agreement, as amended, designates agreed geographic areas which surround and encompass distinct portions of our acreage positions in East Texas defined as "Phases." PVOG began drilling in February 2004 in "Phase I," which includes approximately 7,817 gross (2,173 net) acres comprising a portion of our proved undeveloped acreage. We have a 20% carried interest in the first seven wells drilled in Phase I and a right to participate for up to 30% of additional Phase I wells. Phase II, which includes approximately 6,931 gross (3,325 net) acres of our acreage, must commence no later than July 1, 2005. In Phase II, we have a 20% carried interest in the first two wells and will have a right to participate for up to 50% of additional drilling in Phase II. In December 2003, we received approximately $950,000 in acreage and drilling location cost reimbursement that was applied to reduce current liabilities. For additional information concerning the PVOG agreement, see "Item 2 - Properties."

In January 2004, we completed a private placement of $1 million of 11% senior subordinated notes maturing in 2007 and five year warrants to purchase 175,000 shares of common stock for $1.50 per share. The proceeds of this placement were used for completion of wells with proved developed non-producing reserves, other production enhancements, reduction in current liabilities, placement fees and transaction costs associated with the transaction. These notes were repaid with bank debt in June 2004. In addition, during 2004, the warrants were all exercised for total proceeds of $262,500.

In addition, in April 2004, we closed a private placement of 200,000 shares of common stock for $1,000,000 with a single institutional investor. In June 2004, we closed another private placement of 1,100,000 shares of common stock for $7,535,000 with a group of institutional investors. Proceeds of both these placements were used primarily to fund drilling and development activity in our East Texas properties.

As a result of our improved liquidity in 2004, our bank extended the maturity date of our credit facility to September 1, 2006 and increased the borrowing base to $10,000,000 (as of October 25, 2004) with monthly commitment reductions of $120,000. See "Management's Discussion and Analysis on Plan of Operation."

During 2004, PVOG drilled 17 Cotton Valley wells and completed 15 wells in Phase I under our participation agreement. For 7 of these wells, we had a 20% carried interest and participation for cost for an additional 10% in two of the carried wells. For the remaining wells, we participated with a 30% interest. At December 31, 2004, PVOG was in the process of completing the remaining two wells. During 2004, we conducted recompletion or production enhancement operations on eight wells in Phase III in which we have 100% working interest. These wells have been recompleted in the Pettit, Travis Peak and Cotton Valley formations.

Business Strategy

Our strategy is to create additional value from our East Texas property base through development of quality proved undeveloped properties and exploitation activities focused on adding proved reserves from the inventory of probable and possible drilling locations. We have the following resources:

Experienced Management. The Company's founders have experience in finding, exploiting, developing and operating reserves and companies. Ken L. Kenworthy, Jr., the Company's President, has been active in various aspects of the oil and gas business for over 30 years. He was formerly Chairman and Chief Executive Officer of OEXCO, Inc. ("OEXCO"), an Oklahoma City based privately held oil and gas company. He founded OEXCO in 1980 and successfully managed it until 1995 when it was sold for approximately $13 million. During this 15-year period, OEXCO operated approximately 300 wells. Ken L. Kenworthy, Sr. also has extensive financial experience with private and public businesses, including experience as Chief Financial Officer of CMI Corporation, formerly a New York Stock Exchange listed company that manufactured and sold road-building equipment.

Substantial Drilling and Exploitation Opportunities. We have a substantial inventory of drilling and recompletion projects with an estimated 42 Bcfe of proved undeveloped reserves as of December 31, 2004. These projects include 31 recompletion projects and 67 new drilling locations with proved undeveloped reserves. We expect to locate additional proved drilling and recompletion opportunities as our evaluation and drilling of the property base continues. Based on our December 31, 2004 reserve report, the pre-tax present value of the proved reserves is $83 million with anticipated future development costs of $67 million.

Significant Inventory of Unproved Prospects. We have approximately 388 gross/224 net additional drilling locations in East Texas which we believe have potential in the Pettit, Travis Peak and Cotton Valley formations at depths of 6,000 to 10,000 feet. Approximately 13,954 acres of our leasehold position is held by production, so we do not have rental payments and drilling targets on those leases, they can be held and drilled in order of priority without concern about lease expiration.

Emphasis on Gas Reserves. Production for 2004 was 85% gas and 15% oil. Proved reserves as of December 31, 2004 are 88% gas and 12% oil. We intend to emphasize acquisition and development of gas reserves due to the long term outlook for gas demand, but will continue to maintain a portion of our reserves in oil.

Joint Development of East Texas. Our participation agreement with PVOG enables us to participate in the development of our East Texas property at a faster pace than we could fund independently. By having an industry partner with greater financial and other resources, we are able to accelerate the drilling and development of this property base while still participating at meaningful ownership levels. We consider that our relationship with PVOG is good.

Our principal executive office is located at 9400 North Broadway, Suite 600, Oklahoma City, Oklahoma, 73114 and our telephone number is (405) 600-0711.

Marketing

Our ability to market oil and gas often depends on factors beyond our control. The potential effects of governmental regulation and market factors, including alternative domestic and imported energy sources, available pipeline capacity, and general market conditions are not entirely predictable.

Natural Gas. Natural gas is generally sold pursuant to individually negotiated gas purchase contracts, which vary in length from spot market sales of a single day to term agreements that may extend several years. Customers who purchase natural gas include marketing affiliates of the major pipeline companies, natural gas marketing companies, and a variety of commercial and public authorities, industrial, and institutional end-users who ultimately consume the gas. Gas purchase contracts define the terms and conditions unique to each of these sales. The price received for natural gas sold on the spot market may vary daily, reflecting changing market conditions. The deliverability and price of natural gas are subject to both governmental regulation and supply and demand forces.

Substantially all of our gas from our East Texas company-operated wells is initially sold to our wholly owned subsidiary, Endeavor Pipeline Inc. ("Endeavor"), which in turn sells gas to unrelated third parties. All of our gas is currently sold under contracts providing for market sensitive terms which are terminable with 30-60 day notice by either party without penalty. This means that we enjoy both the high prices in increasing price markets and suffer the price declines when gas prices decline. In addition, PVOG markets 100% of the gas produced from wells operated by PVOG in Phase I of our joint development under the terms of month-to-month contracts on the spot market at a price with market sensitive terms.

Crude Oil. Oil produced from our properties will be sold at the prevailing field price to one or more of a number of unaffiliated purchasers in the area. Generally, purchase contracts for the sale of oil are cancelable on 30-days notice. The price paid by these purchasers is an established market or "posted" price that is offered to all producers.

We do not currently intend to enter into any long-term contracts to sell natural gas or crude oil or to enter into any hedging transactions. None of our gas or oil sales contracts have a term of more than one year.

In 2004, our largest purchasers were Crosstex Pipeline Company, PVOG and TEPPCO Crude, which accounted for 53%, 18% and 15% of total oil and natural gas sales. We do not believe that the loss of any of our purchasers would have a material adverse affect on our operations as there are other purchasers active in the market.

Regulation

Exploration and Production. The exploration, production and sale of oil and gas are subject to various types of local, state and federal laws and regulations. These laws and regulations govern a wide range of matters, including the drilling and spacing of wells, allowable rates of production, restoration of surface areas, plugging and abandonment of wells and requirements for the operation of wells. Our operations are also subject to various conservation requirements. These include the regulation of the size and shape of drilling and spacing units or proration units and the density of wells which may be drilled and the unitization or pooling of oil and gas properties. In this regard, some states allow forced pooling or integration of tracts to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. All of these regulations may adversely affect the rate at which wells produce oil and gas and the number of wells we may drill. All statements in this report about the number of locations or wells reflect current laws and regulations.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

Environmental Matters. The discharge of oil, gas or other pollutants into the air, soil or water may give rise to liabilities to the government and third parties and may require us to incur costs to remedy discharges. Natural gas, oil or other pollutants, including salt water brine, may be discharged in many ways, including from a well or drilling equipment at a drill site, leakage from pipelines or other gathering and transportation facilities, leakage from storage tanks and sudden discharges from damage or explosion at natural gas facilities of oil and gas wells. Discharged hydrocarbons may migrate through soil to water supplies or adjoining property, giving rise to additional liabilities.

A variety of federal and state laws and regulations govern the environmental aspects of natural gas and oil production, transportation and processing and may, in addition to other laws, impose liability in the event of discharges, whether or not accidental, failure to notify the proper authorities of a discharge, and other noncompliance with those laws. Compliance with such laws and regulations may increase the cost of oil and gas exploration, development and production, although we do not anticipate that compliance will have a material adverse effect on our capital expenditures or earnings. Failure to comply with the requirements of the applicable laws and regulations could subject us to substantial civil and/or criminal penalties and to the temporary or permanent curtailment or cessation of all or a portion of our operations.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "superfund law," imposes liability, regardless of fault or the legality of the original conduct, on some classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a disposal site or sites where the release occurred and companies that dispose or arrange for disposal of the hazardous substances found at the time. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and severable liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We could be subject to the liability under CERCLA because our drilling and production activities generate relatively small amounts of liquid and solid waste that may be subject to classification as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act of 1976, as amended ("RCRA"), is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

There are numerous state laws and regulations in the states in which we operate which relate to the environmental aspects of our business. These state laws and regulations generally relate to requirements to remediate spills of deleterious substances associated with oil and gas activities, the conduct of salt water disposal operations, and the methods of plugging and abandonment of oil and gas wells which have been unproductive. Numerous state laws and regulations also relate to air and water quality.

We do not believe that our environmental risks will be materially different from those of comparable companies in the oil and gas industry. We believe our present activities substantially comply, in all material respects, with existing environmental laws and regulations. Nevertheless, we cannot assure you that environmental laws will not result in a curtailment of production or material increase in the cost of production, development or exploration or otherwise adversely affect our financial condition and results of operations. Although we maintain liability insurance coverage for liabilities from pollution, environmental risks generally are not fully insurable.

In addition, because we have acquired and may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Marketing and Transportation. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and the Federal Energy Regulatory Commission ("FERC") that affect the economics of natural gas production, transportation and sales. In addition, the FERC is continually proposing and implementing new rules affecting segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation.

The ultimate impact of the complex rules and regulations issued by the FERC since 1985 cannot be predicted. We cannot predict what further action the FERC will take on these matters. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with which we compete.

Additional proposals and proceedings that might affect the natural gas industry are frequently made before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Our sales of crude oil and condensate are currently not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. However, we do not believe that these regulations affect us any differently than other crude oil producers.

Gas Gathering

We have acquired, constructed and own, through a wholly owned subsidiary, Endeavor Pipeline, Inc., gas gathering lines and compression equipment for gathering and delivering of natural gas from our East Texas properties that we operate. As of December 31, 2004, this gathering system consisted of approximately 35 miles of gathering lines and one Ajax DPC-360, 360 horsepower, two-stage compressor that collect and compress gas from approximately 95% of our gas production from company-operated wells in both 2003 and 2004. This system enables us to improve the control over our production and enhances our ability to obtain access to pipelines for ultimate sale of our gas. We only gather gas from wells in which we own an interest. Remaining gas is gathered by unrelated third parties. Endeavor also serves as first purchaser of gas from wells for which we are the operator. See "Business-Marketing."

PVOG has installed and operates gathering facilities to each of the wells drilled and operated by PVOG in Phase I of our joint development. PVOG charges us a gathering fee of $0.10/MMBtu and actual cost of compression plus five percent (5%) for all gas gathered at the wellhead and redelivered to a central sales point.

Competition

We compete with major integrated oil and gas companies and independent oil and gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which could adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have operated for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Recent increased oil and gas drilling activity in East Texas has resulted in increased demand for drilling rigs and other oilfield equipment and services. We have and may continue to experience occasional or prolonged shortages or unavailability of drilling rigs, drill pipe and other material used in oil and gas drilling. Such unavailability could result in increased costs, delays in timing of anticipated development or cause interests in undeveloped oil and gas leases to lapse.

Facilities

As of December 31, 2004, we leased approximately 6,749 square feet in Oklahoma City, Oklahoma for our corporate headquarters. The annual rental cost is approximately $89,235.

Employees

As of December 31, 2004, we had 11 full-time employees of which three are management and the balance are clerical or technical employees. This compares to eight full-time employees at December 31, 2003. We also use seven independent contractors to assist in field operations. We believe our relations with our employees are satisfactory. Our employees are not covered by a collective bargaining agreement.

Certain Technical Terms

The terms whose meanings are explained in this section are used throughout this document:

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

Bcf. Billion cubic feet.

Bcfe. Billion cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

Btu. British thermal unit, which is the heat required to raise the temperature of a one pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

BBtu. Billion Btus.

Developed Acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Location. A location on which a development well can be drilled.

Development Well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive in an attempt to recover proved undeveloped reserves.

Drilling Unit. An area specified by governmental regulations or orders or by voluntary agreement for the drilling of a well to a specified formation or formations which may combine several smaller tracts or subdivides a large tract, and within which there is usually some right to share in production or expense by agreement or by operation of law.

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

Estimated Future Net Revenues. Estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development costs, and future abandonment costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to deprecation, depletion and amortization.

Exploratory Well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Gross Acre. An acre in which a working interest is owned.

Gross Well. A well in which a working interest is owned.

Infill Drilling. Drilling for the development and production of proved undeveloped reserves that lie within an area bounded by producing wells.

Injection Well. A well which is used to place liquids or gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field or productive horizons.

Lease Operating Expense. All direct costs associated with and necessary to operate a producing property.

MBbls. Thousand barrels.

MBtu. Thousand Btus.

Mcf. Thousand cubic feet.

Mcfpd. Thousand cubic feet per day.

Mcfe. Thousand cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

MMBbls. Million barrels.

MMBtu. Million Btus.

MMcf. Million cubic feet.

MMcfe. Million cubic feet of natural gas equivalent, determined using the ratio of one Bbl of oil or condensate to six Mcf of natural gas.

Natural Gas Liquids. Liquid hydrocarbons which have been extracted from natural gas (e.g., ethane, propane, butane and natural gasoline).

Net Acres or Net Wells. The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX. New York Merchantile Exchange.

Operator. The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease, usually pursuant to the terms of a joint operating agreement among the various parties owning the working interest in the well.

Present Value. When used with respect to oil and gas reserves, present value means the Estimated Future Net Revenues discounted using an annual discount rate of 10%.

Productive Well. A well that is producing oil or gas or that is capable of production.

Proved Developed Reserves. Proved reserves are expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included as proved developed reserves only after testing by pilot project or after the operation of an installed program as confirmed through production response that increased recovery will be achieved.

Proved Reserves. 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 existing economic and operating conditions; i.e., prices and costs as of the date the estimate is made. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Undeveloped Reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances do estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery techniques is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

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

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale), but generally does not require the owners to pay any portion of the costs of drilling or operating wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of a leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with the transfer to a subsequent owner.

Secondary Recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and water flooding are examples of this technique.

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

Waterflood. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working Interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

Workover. To carry out remedial operations on a productive well with the intention of restoring or increasing production.

Item 2. PROPERTIES

General

As of December 31, 2004, we owned properties in the following productive fields and basins in the United States:

- East Texas, North Carthage Field and NE Louisiana, Waskom Field;

- The Tatum Basin Crossroads in Southeast New Mexico.

The following table sets forth certain information regarding our activities in each of these areas as of December 31, 2004.

	East Texas and Louisiana	Southeast New Mexico	Total
Property Statistics:			
Proved reserves (MMcfe)	63,038	1,271	64,309
Percent of total proved reserves	99%	1%	100%
Gross producing wells	59	7	66
Net producing wells	38.7	5.6	44.3
Gross acreage	23,329	1,760	25,059
Net acreage	12,659	1,478	14,135
Proved developed reserves (MMcfe)	22,000	481	22,481
Proved undeveloped reserves (MMcfe)	41,038	790	41,828
Estimated total future development costs ($000s)	66,011	800	66,811
Estimated 2005 development costs ($000s)	15,000	---	15,000
Proved undeveloped locations	66	1	67
Year ended December 31, 2004 results:			
Production (net MMcfe)	1,178	53	1,231
Average net daily production (Mcfe)	3,227	145	3,372

Additional information related to our oil and gas activities is included in Notes I and J to the financial statements beginning on Page F-1.

East Texas

The East Texas properties are located in Harrison and Panola Counties, Texas. These properties contain approximately 22,729 gross (12,288 net) acres with rights covering the Travis Peak, Pettit, Glen Rose and Cotton Valley formations. Our East Texas properties have 62.6 Bcfe of proved reserves or 97% of our total proved reserves at December 31, 2004, of which 41.0 Bcfe is classified as proved undeveloped.

We have interests in 54 gross (36.0 net) producing wells in East Texas, of which we operate 36. Average daily production net to our interest for 2004 was 2,834 Mcf of gas and 62 Bbls of oil. Production is primarily from the Betheny, Blocker and Waskom Fields. The producing lives of these fields are generally 12 to 70 years. We have identified productive zones in the existing wells that are currently behind pipe and thus are not currently producing. These zones can be brought into production as existing reserves are depleted. The Blocker and Betheny areas include 36 gross (30.7 net) wells in Harrison County which produce gas that is gathered, compressed and sold by Endeavor. Gas sold from the Blocker area has a high MMBtu content which results in a net price above NYMEX average daily Henry Hub natural gas price. Oil is sold separately at a slight premium to the average NYMEX Sweet Crude Cushing price, inclusive of deductions. Most of the planned development will be added to existing gathering systems under comparable contracts.

The undeveloped acreage in these areas lies on Sabine Uplift just north of the Carthage Field. The area has 29 producing reservoirs at depths from 3,000 to 10,000 feet. The reservoir trends are similar to river channels and beach barrier bars and are generally substantial in length and sometimes width. These features occur in more than one producing horizon and we give first priority to drilling locations where a single well can drill through two or more producing zones. This increases the reserves recoverable through a single wellbore. We believe the natural gas development opportunities on this property base are substantial and abundant. Our proved developed non-producing and proved undeveloped reserves are significant in this region consisting of 48.8 Bcfe, frequently located at the intersection of multiple crossing reservoir trends. Each well generally penetrates multiple potentially productive formations, including the Pettit, Travis Peak and Cotton Valley.

On December 29, 2003, we executed a definitive participation agreement with PVOG for the joint development of our Cotton Valley, Travis Peak and Pettit prospects located in East Texas. The agreement was amended on several occasions in 2004. This agreement, as amended, designates agreed geographic areas which surround and encompass distinct portions of our acreage positions in East Texas defined as "Phases." PVOG began drilling in February 2004 in "Phase I," which includes approximately 7,817 gross (2,173 net) acres comprising a portion of our proved undeveloped acreage. GMX has a 20% carried interest in the first wells drilled in Phase I and a right to participate for 30% of additional Phase I wells. PVOG has drilled and completed 15 wells in 2004 on the Phase I acreage. Phase II, which includes approximately 6,931 gross (3,325 net) acres of our acreage, must commence no later than July 1, 2005. In Phase II, we have a 20% carried interest in the first two wells and a right to participate for up to 50% of additional drilling in Phase II. At inception, we received approximately $950,000 in acreage and drilling location cost reimbursement which was applied to reduce current liabilities. During 2004, we received an additional $125,541 in drilling location cost reimbursement.

The PVOG agreement also designates areas of mutual interest ("AMIs") in which GMX and PVOG agree that they will have rights to jointly acquire acreage until December 2007. The Phase I AMI consist of 20,500 acres in which GMX and PVOG have agreed to share future acreage acquisitions on a 70% PVOG/30% GMX basis. The Phase II AMI consists of 22,400 acres and a 50% PVOG/50% GMX sharing ratio. The Phase III AMI consists of 15,360 acres and is an area surrounding GMX's existing wells. GMX has granted to PVOG a right of first refusal on any sale of acreage in Phase III and PVOG is restricted from acquiring acreage in Phase III until one year after termination of the participation agreement, unless GMX no longer owns acreage in Phase III. In 2004, we jointly acquired 2,665 gross acres in Phase I and 670 acres in Phase II.

The participation agreement originally limited PVOG to the use of one rig. During a portion of 2004, PVOG used two rigs under an amendment to our agreement whereby PVOG agreed to purchase a dollar denominated production payment from us to finance our share of costs of drilling using the second rig. This arrangement was terminated in November 2004 and since that date, only one rig was used throughout the remainder of 2004 and early 2005. We received $1,929,029 in funding from PVOG under this arrangement. In March 2005, we entered into a further amendment to the joint participation agreement permitting PVOG to use two rigs, when one can be located, which permits us to share in the use of the second rig for our own account in drilling in Phase III, on an alternating basis with PVOG. We and PVOG each have the right to use the second rig for up to three consecutive wells. We will pay for the rig when we use it on the same terms as PVOG. Either party may terminate the multiple rig provisions on 60 days notice subject to the terms of any drilling contract for the second rig.

During 2004, GMX participated in 17 gross (4.6 net) new wells drilled by PVOG in Phase I and recompleted eight wells in Phase III. Fifteen of the new wells were drilled and completed and had sales in 2004. At year end, the remaining two were in the process of drilling or completion. The success rate was 100% on wells drilled and completed in 2004. The pace of future development of this property will depend on the pace of PVOG's activity under our joint participation agreement described above, availability of capital, future drilling results, the general economic conditions of the energy industry and on the price we receive for the natural gas and crude oil produced. There is a potential for up to 455 gross (263 net) locations of Cotton Valley wells in our East Texas acreage assuming an ultimate well density of two wells in each 80-acre tract.

At December 31, 2004, Sproule Associates, Inc., our independent reserve engineering firm, assigned a total of 13.8 Bcfe of proved reserves to the completed East Texas wells, 7.8 Bcfe to our proved developed non-producing wells, and 30.5 Bcfe of proved undeveloped reserves to our 66 proved undeveloped locations in East Texas.

As discussed above, in March 2005, we and PVOG reached an agreement to use a second rig in Phases I and II. When a second rig is located and put in service, drilling in East Texas will be accelerated. We are also seeking an additional rig for our own use in Phase III drilling. Depending on rig availability and funding, we expect PVOG to drill 13-25 new Cotton Valley wells in Phase I and two Cotton Valley wells in Phase II and we expect to drill 2-16 Cotton Valley wells in Phase III. We also plan to recomplete 4-6 wells in Phase III. We will fund our share of this drilling at the low end of these ranges from internal cash flow and borrowings under our bank credit facility. If drilling is proposed at the higher ranges, we may need outside sources of capital to fund our share.

Northwestern Louisiana

The Louisiana properties are located in Clairborne, Caddo, Catahoula and Webster parishes. These properties contain approximately 600 gross (369 net) acres in the Waskom Field with production from the Cotton Valley, Hosston and Rodessa formations. We have five gross (2.6 net) producing wells, three of which we operate. Production is predominately oil. Louisiana proved reserves are 0.4 Bcfe and represent approximately 1% of proved reserves as of December 31, 2004. Average daily production net to our interest for 2003 was 2 Bbls of oil and 8 Mcf of gas. We are in the process of evaluation of additional behind pipe and undeveloped reserves in the region. The wells are producing around a piercement saltdome which has produced numerous structural traps for oil.

Southeast New Mexico

Our Southeast New Mexico properties are located in Lea and Roosevelt counties and consist of approximately 1,760 gross (1,478 net) acres. The acreage lies on the northwestern edge of the Midland Basin, defined as the Tatum Basin. Existing production is from three zones—the Bough C, Abo and San Andreas—at depths ranging from 9,500 to 10,000 feet. Proved reserves in Southeast New Mexico are 1.3 Bcfe and represent 1% of our total proved reserves as of December 31, 2004. Average daily production net to our interests for 2004 from our 7 gross (5.6 net) producing wells in this area was 31 Mcf of gas and 19 Bbls of oil.

Third party drilling activity in the vicinity of our properties also suggests that deeper exploration may be warranted to the Atoka, Morrow and Devonian formations. In 2004, we entered into a farmout with Yates Petroleum Corporation which completed 3D seismic evaluations of these formations. We plan to participate with Yates in a 12,000-foot Morrow sand test expected to commence in April 2005. We will have a 23% working interest in this well and also have retained a 5.75% overriding royalty interest.

Reserves

As of December 31, 2004, Sproule Associates Inc. estimates our proved reserves are 64 Bcfe. An estimated 22 Bcfe is expected to be produced from existing wells and another 42 Bcfe or 65% of the proved reserves, is classified as proved undeveloped. All of our proved undeveloped reserves are on locations that are adjacent to wells productive in the same formations. As of December 31, 2004, we had interests in 66 gross producing wells, 39 of which we operate.

The following table shows the estimated net quantities of our proved reserves as of the dates indicated and the Estimated Future Net Revenues and Present Values attributable to total proved reserves at such dates.

		Years Ended December 31,		
		2002	2003	2004
Proved Developed:				
Gas (MMcf)		16,501	18,277	18,980
Oil (MBbls)		604	568	584
	Total (MMcfe)	20,125	21,685	22,484
Proved Undeveloped:				
Gas (MMcf)		40,181	26,752	37,908
Oil (MBbls)		1,060	755	653
	Total (MMcfe)	46,541	31,282	41,826
Total Proved:				
Gas (MMcf)		56,683	45,029	56,888
Oil (MBbls)		1,663	1,323	1,237
	Total (MMcfe)	66,663	52,967	64,309
Estimated Future Net Revenues (1)($000s)		$186,336	$178,348	$ 214,278
Present Value(1)($000s)		$ 80,614	$ 71,192	$ 83,237
Standardized Measure (1) ($000s)		$ 54,312	$ 47,975	$ 64,231

(1) The prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as of period end. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. See "Note J – Supplemental Information on Oil and Gas Operations" for information about the standardized measure of discounted future net cash flows. We believe that the Estimated Future Net Revenue and Present Value are useful measures in addition to standardized measure as it assists in both the determination of future cash flows of the current reserves as well as in making relative value comparisons among peer companies. The standardized measure is dependent on the unique tax situation of each individual company, while the pre-tax Present Value is based on prices and discount factors which are consistent from company to company. We also understand that securities analysts use this measure in similar ways.

There was a significant decrease in proved reserves from December 31, 2002 to December 31, 2003. We produced 1.1 Bcfe which was not replaced due to the absence of drilling in 2003. In addition, our proved reserve estimates at December 31, 2003 were revised downward by 13.7 Bcfe compared to December 31, 2002 primarily as a result of a participation agreement with PVOG in December, 2003, under which PVOG acquired certain rights in our East Texas properties. The increase in proved reserves in 2004 is primarily attributable to discoveries resulting from our East Texas drilling results and increases in commodity prices.

Approximately 65% of our proved reserves are undeveloped. By their nature, estimates of undeveloped reserves are less certain. In addition, the quantity and value of our proved undeveloped reserves is dependent upon our ability to fund the associated development costs which were a total of an estimated $67 million as of December 31, 2004, of which $15 million is scheduled to be expended in 2005. These estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

Estimates of the quantity and value of our proved undeveloped reserves are dependent upon the amount of interest that we expect to own in these reserves. In connection with the PVOG participation agreement executed in December of 2003, PVOG's rights in Phase II of the agreement are contingent upon PVOG's successful completion of Phase I and the drilling of two carried interest wells in Phase II before July 1, 2005. Our year end reserve estimates assume that PVOG will earn all of its rights in the Phase II acreage. Our reserve estimates would be increased if PVOG does not earn rights in Phase II.

The Estimated Future Net Revenues and Present Value are highly sensitive to commodity price changes and commodity prices have recently been highly volatile. The prices used to calculate Estimated Future Net Revenues and Present Value of our proved reserves as of December 31, 2004 were $43.45 per barrel for oil and $6.149 per Mmbtu for gas, adjusted for quality, contractual agreements, regional price variations and transportation and marketing fees. These period end prices are not necessarily the prices we expect to receive for our production but are required to be used for disclosure purposes by the SEC. We estimate that if all other factors (including the estimated quantities of economically recoverable reserves) were held constant, a $1.00 per Bbl change in oil prices and a $.10 per Mcf change in gas prices from those used in calculating the Present Value would change such Present Value by $511,800 and $2,374,000, respectively, as of December 31, 2004.

Sproule Associates, Inc., our independent reserve engineers, prepared the estimates of proved reserves as of December 31, 2002, 2003, and 2004.

No estimates of our proved reserves comparable to those included in this report have been included in reports to any federal agency other than the Securities and Exchange Commission.

Costs Incurred

The following table shows certain information regarding the costs incurred by us in our acquisition and development activities during the periods indicated. We have not incurred any exploration costs.

	Year ended December 31,		
	2002	**2003**	**2004**
Property acquisition costs:			
Proved	$ 120,157	$ 57,565	$ ---
Unproved	84,672	5,212	851,617
Development costs	2,812,876	173,840	7,716,073
Total	$ 3,017,705	$ 236,617	$ 8,567,690

Drilling Results

We drilled or participated in the drilling of wells as set out in the table below for the periods indicated. The table was completed based upon the date drilling commenced. We did not acquire any wells or conduct any exploratory drilling during these periods. You should not consider the results of prior acquisition and drilling activities as necessarily indicative of future performance, nor should you assume that there is necessarily any correlation between the number of productive wells acquired or drilled and the oil and gas reserves generated by those wells.

	Year Ended December 31,					
	2002		2003		2004	
Development wells:	Gross	Net	Gross	Net	Gross	Net
Gas	---	---	---	---	15	4
Oil	---	---	---	---	---	---
Dry	---	---	---	---	---	---
Total	---	---	---	---	15	4

We also recompleted 8 gross and net in 2004. We did not recomplete any wells in 2003 and 2002.

Acreage

The following table shows our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2004. Excluded is acreage in which our interest is limited to royalty, overriding royalty and other similar interests.

	Developed		Undeveloped	
Location	**Gross**	**Net**	**Gross**	**Net**
East Texas and Louisiana	15,804	9,445	7,526	3,212
Southeast New Mexico	1,760	1,478	---	---
Total	17,564	10,923	7,526	3,212

Title to oil and gas acreage is often complex. Landowners may have subdivided interests in the mineral estate. Oil and gas companies frequently subdivide the leasehold estate to spread drilling risk and often create overriding royalties. When we purchased the properties, the purchase included title opinions prepared by counsel in the several states analyzing mineral ownership in each well drilled. Further, for each producing well there is a division order signed by the current recipients of payments from production stipulating their assent to the fraction of the revenues they receive. We obtain similar title opinions with respect to each new well drilled. While these practices, which are common in the industry, do not assure that there will be no claims against title to the wells or the associated revenues, we believe that we are within normal and prudent industry practices. Because many of the properties in our current portfolio were purchased out of bankruptcy in 1998, we have the advantage that any known or unknown liens against the properties were cleared in the bankruptcy.

Productive Well Summary

The following table shows our ownership in productive wells as of December 31, 2004 Gross oil and gas wells include one well with multiple completions. Wells with multiple completions are counted only once for purposes of the following table.

Type of Well	Productive Wells Gross	Net
Gas	46	29.8
Oil	20	14.5
Total	66	44.3

Item 3. LEGAL PROCEEDINGS

None.

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

There were no matters submitted to a vote of security holders during the fourth quarter of 2004.

PART II

Item 5. MARKET FOR COMMON EQUITY RELATED STOCKHOLDER MATTERS, AND SMALL BUSINESS ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock and Class A Warrant Information

The high and low bid prices for our Common Stock and Class A Warrants as listed on the NASDAQ National Market as applicable during the periods described below were as follows:

	High	Low
Year Ended December 31, 2003		
First Quarter		
Common Stock	$ 1.96	$ 1.06
Class A Warrants	0.50	0.05
Second Quarter		
Common Stock	2.14	0.63
Class A Warrants	0.49	0.04
Third Quarter		
Common Stock	2.23	1.33
Class A Warrants	0.19	0.09
Fourth Quarter		
Common Stock	4.50	1.30
Class A Warrants	0.72	0.09
Year Ended December 31, 2004		
First Quarter		
Common Stock	6.08	2.45
Class A Warrants	0.98	0.27
Second Quarter		
Common Stock	8.30	5.10
Class A Warrants	1.48	0.63
Third Quarter		
Common Stock	7.80	5.31
Class A Warrants	1.00	0.40
Fourth Quarter		
Common Stock	7.75	5.86
Class A Warrants	0.93	0.50

These quotations reflect inter-dealer prices, without retail mark-up, mark-down or commission and may not represent actual transactions.

As of March 1, 2005, there were 46 record owners of our Common Stock and approximately 1,264 beneficial owners.

Each Class A Warrant entitles the holder to purchase one share of common stock for $12.00 per share until the warrants expire on February 12, 2006.

We have never declared or paid any cash dividends on our shares of common stock and do not anticipate paying any cash dividends on our shares of common stock in the foreseeable future. Currently, we intend to retain any future earnings for use in the operation and expansion of our business. Any future decision to pay cash dividends will be at the discretion of our board of directors and will be dependent upon our financial condition, results of operations, capital requirements and other facts our board of directors may deem relevant. The payment of dividends is currently prohibited under the terms of our revolving credit facility and may be similarly restricted in the future.

Equity Compensation Plan Information

The following table sets forth information as of December 31, 2004 relating to equity compensation plans.

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options	Weighted-Average Exercise Price of Outstanding Options	Remaining Shares Available for Future Issuance Under Equity Compensation Plans
Equity Compensation Plans Approved by Shareholders	254,000	$4.29	296,000
Equity Compensation Plans Not Approved by Shareholders	60,000	$1.00	---

The 60,000 shares issuable under the equity compensation plan not approved by shareholders relate to a single option grant to a consultant as a part of his compensation arrangements.

Recent Sales of Unregistered Securities

None during the fourth quarter of 2004.

Purchases of Equity Securities by the Small Business Issuer

The following table provides information about our purchases of Class A Warrants in the open market during the fourth quarter of 2004.

Period	Total Number of Warrants Purchased		Average Price Paid per Warrant	Total Number of Warrants Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 2004	500	$	.71	500	(1)
November	3,300		.60	3,300	(1)
December 2004.....	90,800		.65	90,800	(1)
Total 2004............	94,600	$	.65	94,600	(1)

(1) We announced on October 5, 2004 a warrant repurchase program authorizing management to spend up to $250,000 to acquire our Class A Warrants in the open market at prices deemed attractive by management from time to time. Through December 31, 2004, $61,930 had been spent on such repurchases. There has been no time limit set for completion of the repurchase program. The maximum number of warrants that may be purchased is not determinable as it is dependent on the price of the warrants.

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

Selected Financial Data

The following table presents a summary of our financial information for the periods indicated. It should be read in conjunction with our consolidated financial statements and related notes (beginning on page F-1 at the end of this report) and the discussion below.

	Years Ended December 31, 2002	2003	2004
Statement of Operations Data:			
Oil and gas sales	$ 5,970,792	$ 5,367,370	$ 7,689,882
Interest and other income	17,550	21,424	143,828
Total revenues	5,988,342	5,388,794	7,833,710
Lease operations	1,324,481	850,034	1,261,109
Production and severance taxes	382,826	384,069	518,712
General and administrative	2,577,388	1,578,865	1,985,913
Depreciation, depletion and amortization	1,901,976	1,549,678	2,043,485
Interest	510,472	439,313	558,504
Total expenses	$ 6,697,142	$ 4,801,959	$ 6,367,731
Income (loss) before income taxes	(708,800)	586,835	1,465,979
Income tax expense (benefit)	(263,000)	---	24,206
Net income before cumulative effect of a change in accounting principle	$ (445,800)	$ 586,835	$ 1,441,773
Cumulative effect of a change in accounting principle	---	(51,834)	---
Net income (loss) applicable to common shares	$ (445,800)	$ 535,001	$ 1,441,773
Net income (loss) per share – before cumulative effect	$ (.07)	$ .09	$ .19
Cumulative effect	---	(.01)	---
Net income (loss) per share – basic and diluted	$ (.07)	$ .08	$ .19
Weighted average common shares – basic	6,550,000	6,560,000	7,396,880
Weighted average common shares – diluted	6,550,000	6,560,000	7,491,778
Statement of Cash Flows Data:			
Cash provided by (used in) operating activities	$ (2,547,639)	$ 1,014,290	$ 3,708,478
Cash provided by (used in) investing activities	1,267,831	464,315	(8,902,267)
Cash provided by (used in) financing activities	1,820,000	(1,385,000)	5,418,813
Balance Sheet Data (at end of period):			
Oil and gas properties, net	$ 29,359,309	$ 27,660,317	$ 35,956,760
Total assets	33,319,432	31,501,206	40,991,463
Long-term debt, including current portion	8,100,000	6,690,000	3,762,294
Shareholders' equity	21,607,463	22,618,565	32,406,856

Summary Operating and Reserve Data

The following table presents an unaudited summary of certain operating and oil and gas reserve data for the periods indicated.

	Years Ended December 31,		
	2002	2003	2004
Production:			
Oil (MBbls)	70	35	30
Natural gas (MMcf)	1,639	917	1,049
Gas equivalent (MMcfe)	2,059	1,124	1,231
Average Sales Price:			
Oil (per Bbl)	$ 23.48	$ 30.41	$ 40.83
Natural gas (per Mcf)	3.03(1)	4.73(1)	6.15
Average sales price (per Mcfe)	$ 3.22	$ 4.79	$ 6.25
Operating and Overhead Costs (per Mcfe):			
Lease operating expenses	$ .64	$ .74	$ 1.03
Production and severance taxes	.19	.34	.42
General and administrative	1.25	1.40	1.61
Total	$ 2.08	$ 2.48	$ 3.06
Operating Margin (per Mcfe)	$ 1.14	$ 2.31	$ 3.19
Other (per Mcfe):			
Depreciation, depletion and amortization - oil and gas production	$ .92	$ 1.08	$ 1.28
Estimated Net Proved Reserves (as of period-end):			
Natural gas (Bcf)	56.7	45.0	56.9
Oil (MMbls)	1.7	1.3	1.2
Total (Bcfe)	66.7	53.0	64.3
Estimated Future Net Revenues ($MM)(2)(3)	$ 486.3	$ 178.3	$ 214.3
Present Value ($MM)(2)(3)	$ 80.6	$ 71.2	$ 83.2
Standardized measure of discounted future net cash flows ($MM)(4)	$ 54.3	$ 48.0	$ 64.2

(1) Net of results of hedging activities which reduced the average gas price in 2002 $.40 per Mcf and $.48 per Mcf in 2003.

(2) See "Item 1 - Certain Technical Terms."

(3) The prices used in calculating Estimated Future Net Revenues and the Present Value are determined using prices as of period end. Estimated Future Net Revenues and the Present Value give no effect to federal or state income taxes attributable to estimated future net revenues. See "Item 2 - Reserves."

(4) The standardized measure of discounted future net cash flows gives effect to federal and state income taxes attributable to estimated future net revenues. See "Note J – Supplemental Information on Oil and Gas Operations."

Critical Accounting Policies

The preparation of the consolidated financial statements requires us to make a number of estimates and assumptions relating to the reported amounts of assets and liabilities and the disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. When alternatives exist among various accounting methods, the choice of accounting method can have a significant impact on reported amounts. The following is a discussion of our accounting estimates and judgments which management believes are most significant in its application of generally accepted accounting principles used in the preparation of the consolidated financial statements.

Full Cost Calculations

The accounting for our business is subject to special accounting rules that are unique to the oil and gas industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full-cost method. We follow the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and gas properties are generally calculated on a well by well or lease or field basis versus the aggregated "full cost" pool basis. Additionally, gain or loss is generally recognized on all sales of oil and gas properties under the successful efforts method. As a result, our financial statements will differ from companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher oil and gas depreciation, depletion and amortization rate, although this difference could change in periods of lower price environments that result in write-downs of our costs as described below.

The full cost method subjects companies to quarterly calculations of a "ceiling", or limitation on the amount of properties that can be capitalized on the balance sheet. If our capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense. Our discounted present value of estimated future net revenues from our proved oil and natural gas reserves is a major component of the ceiling calculation, and represents the component that requires the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. All of our reserve estimates are prepared by Sproule Associates, Inc.

The passage of time provides more qualitative information regarding estimates of reserves, and revisions are made to prior estimates to reflect updated information. For example, in 2002 our reserves were revised downward by 13.5 Bcfe. There can be no assurance that significant revisions will not be necessary in the future. If future significant revisions are necessary that reduce previously estimated reserve quantities, it could result in a full cost property writedown. In addition to the impact of the estimates of proved reserves on the calculation of the ceiling, estimates of proved reserves are also a significant component of the calculation of the full cost pool amortization.

The estimates of proved undeveloped reserve quantities and values are based on estimated future drilling which assumes that we will have the financing available to fund the estimated drilling costs. If we do not have such financing available at the time projected, the estimates of proved undeveloped reserve quantities and values will change.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the period are generally held constant indefinitely. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but rather are based on such prices and costs in effect as of the end of each quarter when the ceiling calculation is performed.

Because the ceiling calculation dictates that prices in effect as of the last day of the applicable quarter are held constant indefinitely, the resulting value is not indicative of the true fair value of the reserves. Oil and natural gas prices have historically been cyclical and, on any particular day at the end of a quarter, can be either substantially higher or lower than various industry long-term price forecasts. Therefore, oil and natural gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions in the underlying quantities of reserves, should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Capitalized costs are amortized on a composite unit-of-production method based on proved oil and gas reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly.

Asset Retirement Obligations

Our asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with our oil and gas properties. Statement of Financial Accounting Standard ("SFAS") No. 143, "Accounting for Asset Retirement Obligations," requires that the discounted fair value of a liability for an ARO be recognized in the period in which it is incurred with the associated asset retirement cost capitalized as part of the carrying cost of the oil and gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to initial measurement of the ARO, the Company must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through DD&A.

At December 31, 2004, the Company's balance sheet included an estimated liability for ARO of $1,764,631.

Income Taxes

As part of the process of preparing the consolidated financial statements, we are required to estimate the federal and state income taxes in each of the jurisdictions in which we operate. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as derivative instruments, depreciation, depletion and amortization, and certain accrued liabilities for tax and accounting purposes. These differences and the net operating loss carryforwards result in deferred tax assets and liabilities, which are included in our consolidated balance sheet We must then assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. If we believe that recovery is not likely, we must establish a valuation allowance. Generally, to the extent we establish a valuation allowance or increase or decrease this allowance in a period, we must include an expense or reduction of expense within the tax provisions in the consolidated statement of operations. As of December 31, 2004, we estimated that our deferred tax liabilities and deferred tax assets were equal in amount after the effects of our establishing a $229,000 valuation allowance as it is unlikely that we will be able to use our net operating loss carryforwards prior to their expiration.

Results of Operations for the Year Ended December 31, 2004 Compared to the Year Ended December 31, 2003

Oil and Gas Sales. Oil and gas sales in the year ended December 31, 2004 increased 43% to $7,689,882 compared to the year ended December 31, 2003, due to an increase of 10% in production and a 30% increase in the average oil and gas price. The average price per barrel of oil and mcf of gas received in 2004 was $40.83 and $6.15, respectively, compared to $30.41 and $4.73 in the year of 2003. During 2003, we hedged 180,000 Mcf of gas through price swap agreements with a fixed price of $2.664 per Mcf. The price swap agreements reduced sales by $438,400. Oil production for 2004 decreased 5MBbls to 30 MBbls compared to 2003. Gas production increased to 1,049 MMcf compared to 917 MMcf for the year of 2003, an increase of 14%. Increased production in 2004 resulted from drilling and recompleting new wells during the year.

Lease Operations. Lease operations expense increased $411,075 in 2004 to $1,261,109, a 48% increase compared to 2003. Increased expenses resulted from numerous re-works of wells and additional costs of new wells. Lease operations expense on an equivalent unit of production basis was $1.02 per Mcfe in 2004 compared to $.74 per Mcfe for 2003, resulting from re-works and maintenance to enhance production.

Production and Severance Taxes. Production and severance taxes increased 22% to $518,721 in 2004 compared to $384,069 in 2003. Production and severance taxes are assessed on the value of the oil and gas produced prior to the effect of price swap agreements. As a result, the increase resulted primarily from the increase in oil and gas sales prices and an increase in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $494,071 to $2,043,485 in 2004, up 32% from 2003. This increase is due primarily to an increase in production for 2004. The oil and gas depreciation, depletion and amortization rate per equivalent unit of production was $1.28 per Mcfe in 2004 compared to $1.08 per Mcfe in 2003.

Interest. Interest expense for 2004 was $558,504 compared to $439,313 for 2003. This increase is primarily attributable to a higher cost of subordinated debt in the first six months of 2004.

General And Administrative Expense. General and administrative expense for 2004 was $1,985,913 compared to $1,578,865 for 2003, an increase of 26%. This increase of $407,048 was the result of an increase in salaries and payroll expenses of $215,000 from personnel additions, an increase of $64,000 in cost of being public and an $85,000 increase in technical consulting costs. General and administrative expense per equivalent unit of production was $1.65 per Mcfe for 2004 compared to $1.40 per Mcfe for 2003.

Income Taxes. Income tax for year of 2004 was $24,206 as compared to zero in 2003.

Results of Operations for the Year Ended December 31, 2003 Compared to the Year Ended December 31, 2002

Oil and Gas Sales. Oil and gas sales in the year ended December 31, 2003 decreased 10% to $5,367,370 compared to the year ended December 31, 2002 due to decreased production, which was not fully offset by higher prices. The average price per barrel of oil and mcf of gas received in 2003 was $30.41 and $4.73, respectively, compared to $23.45 and $3.03 in 2002. During 2003, we hedged 180,000 Mcf of gas through price swap agreements with a fixed price of $2.664 per Mcf. The price swap agreements reduced sales by $438,400. Oil production for 2003 decreased compared to 2002. Gas production decreased to 916 MMcf in 2003 compared to 1,639 MMcf for 2002, a decrease of 44%. Decreased production and revenues in 2003 resulted from higher decline rates, production down time and a lack of funds to workover or drill wells.

Lease Operations. Lease operations expense decreased $496,968 in 2003 to $827,413, a 38% decrease compared to 2002. Decreased expenses resulted from the sale of Kansas properties and a lack of funds to make material workovers to our wells. Lease operations expense on an equivalent unit of production basis was $.74 per Mcfe in 2003 compared to $.64 per Mcfe for 2002, primarily from the decreased production coupled with fixed costs.

Production and Severance Taxes. Production and severance taxes increased 3% to $384,069 in 2003 compared to $382,826 in 2002. Production and severance taxes are assessed on the value of the oil and gas produced prior to the effect of price swap agreements. As a result, the increase resulted primarily from the increase in oil and gas sales prices mitigated by the decrease in production.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased $329,777 to $1,572,199 in 2003, down 17% from 2002. This decrease is due primarily to a decrease in production for 2003. The oil and gas depreciation, depletion and amortization rate per equivalent unit of production was $1.08 per Mcfe in 2003 compared to $0.92 per Mcfe in 2002.

Interest. Interest expense for the year 2003 was $439,313 compared to $510,472 for the year of 2002. This decrease is primarily attributable to lower debt balances outstanding during 2003.

General And Administrative Expense. General and administrative expense for 2003 was $1,578,865 compared to $2,577,358 for 2002, a decrease of 39%. This decrease of $998,523 was the result of a decrease in salaries and payroll expenses of $741,000 and a decrease in legal and professional fees primarily in connection with the Nabors Drilling lawsuit. The salary decrease was a result of a decrease in administrative personnel. General and administrative expense per equivalent unit of production was $1.40 per Mcfe for the 2003 period compared to $1.25 per Mcfe for the comparable period in 2002.

Income Taxes. Income tax for year of 2003 was $0 as compared to a benefit of $263,000 in 2002. During 2002, we established a valuation allowance for our deferred tax asset. During 2003, we reversed the valuation allowance to the extent of our 2003 income.

Capital Resources and Liquidity

Our business is capital intensive. Our ability to grow our reserve base is dependent upon our ability to obtain outside capital and generate cash flows from operating activities to fund our investment activities. Our cash flows from operating activities are substantially dependent upon oil and gas prices and significant decreases in market prices of oil or gas could result in reductions of cash flow and affect the amount of our capital investment.

Cash Flow—Year Ended December 31, 2004 Compared to Year Ended December 31, 2003. In 2004 we had a positive cash flow from operating activities of $3,708,478 as a result of increased production and higher oil and gas prices during 2004. Our cash flow from operating activities in 2003 was $1,014,290. We expended $8,902,267 on capital expenditures in 2004, primarily on drilling and development costs, compared to receiving a net $464,315 in 2003 after a sale of properties. The cash inflow in 2003 was primarily from the year-end agreement with PVOG. The net cash inflow in 2004 of $5,418,813 from financing activities primarily resulted from sales of common stock in the amount of $8,346,518, offset by repayment of debt.

Cash Flow—Year Ended December 31, 2003 Compared to Year Ended December 31, 2002. In 2003 we had a positive cash flow from operating activities of $1,014,290 as a result of increased oil and gas prices during 2003. Our cash flow from operating activities in 2002 was a deficit of $2,547,639 primarily due to a reduction in net income and decreases in accounts payable of $4,454,155. We received a net $464,315 in cash from investing activities in 2003, compared to 2002 amounts of $1,267,851. The cash inflow in 2003 was primarily from the year-end agreement with PVOG. The cash inflow in 2002 from investing activities primarily resulted from sale of our Kansas properties for $4,245,163 which more than offset additions to oil and gas properties of $3,014,288.

Credit Facility

On October 31, 2000, we entered into a secured credit facility provided by IBC Bank (formerly Local Oklahoma Bank, N.A.). The credit facility provided for a line of credit of up to $15 million (the "Commitment"), subject to a borrowing base which is based on a periodic evaluation of oil and gas reserves which is reduced monthly to account for production ("Borrowing Base"). The amount of credit available to us at any one time under this credit facility is the lesser of the Borrowing Base or the amount of the Commitment. The amount of this Borrowing Base has been adjusted from time to time, most recently as of October 25, 2004 to $10,000,000 with a monthly required reduction of $120,000.

The credit facility has been amended on several occasions to waive non-payment default or to extend the maturity. In June 2004, a new maturity date of September 1, 2006 was established. During 2004, we were able to reduce the amount outstanding under this facility from proceeds of stock sales and cash flow from operations.

As of December 31, 2004, we had $1,849,837 outstanding under the facility. As of March 1, 2005, we had $3,150,000 outstanding and $6,250,000 available for borrowing.

Borrowings under the credit facility bear interest at the prime rate to prime plus 1% depending on the level of actual borrowings in relation to the Borrowing Base. The credit facility requires payment of an annual facility fee equal to 1 /2 % on the unused amount of the Borrowing Base. We are obligated to make principal payments if the amount outstanding would exceed the Borrowing Base. Borrowings under the credit agreement are secured by substantially all of our oil and gas properties. The credit facility contains various affirmative and restrictive covenants. The material covenants, which must be satisfied unless the lender otherwise agrees:

- Require us to maintain an adjusted current ratio as defined in the credit facility of 1 to 1.
- Require us to maintain a quarterly debt service coverage ratio of at least 1.1 to 1.0. The debt service coverage ratio is defined in the credit facility generally as net income plus depreciation, depletion and amortization plus interest expense divided by the quarterly principal reduction requirements plus interest and current maturities of other long-term debt.
- Require us to maintain a ratio of indebtedness to tangible net worth of not more than 1.5 to 1.
- Prohibit any liens or any other debt in excess of $100,000.
- Prohibit sales of assets of more than $100,000.
- Prohibit payment of dividends or repurchases of stock.
- Prohibit mergers or consolidations with other entities without being the controlling entity.
- Prohibit material changes in management.

During 2005, we expect to seek proposals from other banks to determine whether we may be able to obtain more favorable terms for our bank credit facility as a result of our improved financial condition and results of operation.

Other 2004 Financings

Subordinated Notes. In January 2004, we raised $1 million from the sale of 11% senior subordinated notes due January 31, 2007 and five-year detachable warrants to purchase 175,000 shares of common stock for $1.50 per share. The price of our common shares as of that date was $4.01. For accounting purposes, the fair value of the in-the-money warrants increased the effective interest rate of the notes. Those notes were repaid in June 2004 with bank debt. Also, the warrants were all exercised during 2004 resulting in proceeds of $262,500.

Common Stock Private Placements. In April 2004, we closed a private placement of 200,000 shares of common stock for $1,000,000 with a single institutional investor. Also, in June 2004, we completed another private placement and sold 1,100,000 shares of common stock for $7,535,000. Proceeds of these have been used for general corporate purposes, primarily drilling in our East Texas properties.

PVOG Financing. As described in Part I, Item 2. Properties – East Texas, we entered into an arrangement with PVOG to purchase dollar denominated production payments from us on wells drilled with a second rig during a portion of 2004. Under this agreement, PVOG provided to us $1.9 million in funding for our share of costs of four wells drilled with the second rig, which is repayable solely from 75% of our share of production revenues from these wells without interest. As of December 31, 2004, the Present Value of our interest in the wells funded in this manner was $2.8 million.

Working Capital

At December 31, 2004, we had a working capital deficit of $392,274. Including availability under our credit facility, our working capital as of December 31, 2004 would have been $7,517,889. Total bank and PVOG financing debt outstanding at December 31, 2004 was $3.76 million, representing 10.4% of our total capitalization.

Commitments and Capital Expenditures

The following table reflects the Company's contractual obligations as of December 31, 2004.

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	Payments Due by Period				
Long-term debt	$ 1,849,837	$ ----	$ 1,849,837	$ ---	$ ---
Operating leases	232,755	100,357	132,398	---	---
PVOG Financing	1,912,457	433,933	1,478,523	---	---
Total	$ 3,995,049	$ 534,290	$ 3,460,758	$ ---	$ ---

Other than obligations under our credit facility and the PVOG financing, our commitments for capital expenditures relate to development of oil and gas properties. We will not enter into drilling or development commitments until such time as a source of funding for such commitments is known to be available, either through financing proceeds, joint venture arrangements, internal cash flow, additional funding under our bank credit facility or working capital.

Liquidity and Financing Considerations

As a result of the participation agreement with PVOG, our 2004 financing and drilling activities and higher commodity prices, our financial condition and liquidity substantially improved. We expect production from our wells drilled and completed in 2004 and 2005 to provide cash flow to support additional drilling. Our 2005 cash flow should be significantly greater than 2004 assuming commodity prices do not decrease significantly. In addition, we will have availability under our credit facility ($6,250,000 as of March 15, 2005 based on the last Borrowing Base determination of $10 million effective as of October 25, 2004) and expect that increases in the Borrowing Base may occur during the year as additional production is established. As a result, we believe we could fund from these sources from $15 to $20 million in capital expenditures, depending on gas prices and drilling results. If additional rigs become available in East Texas during the year, we would need additional financing from drilling funds or additional equity or debt placements to fund additional capital expenditures.

Our Class A Warrants are exercisable at $12 per share and if the 1,107,215 warrants outstanding as of March 15, 2005 were exercised, we would receive $13 million from sales of 1,107,215 shares of common stock. These warrants expire in February 2006 and we expect them to be exercised prior to that date if they are in the money. Accordingly, we may defer additional equity placements if, based on our stock price, it appears these warrants will be exercised.

Price Risk Management

In the past, we have entered into financial price risk management activities with respect to a portion of projected oil and gas production through financial price swaps whereby we received a fixed price for our production and pay a variable market price to the contract counterparty. These activities are intended to reduce our exposure to oil and gas price fluctuations. We may enter into these instruments when we believe forward market conditions are relatively favorable. The gains and losses realized as a result of these activities are substantially offset in the cash market when the commodity is delivered.

Effect of Accounting Standards

In June 2001, FASB Statement No. 143, Accounting for Asset Retirement Obligations, was issued. Statement 143 required us to record the fair value of an asset retirement obligation as a liability in the period in which we incur a legal obligation associated with the retirement of tangible long lived assets that result from the acquisition, construction, development, and/or normal use of the assets. We also recorded a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. We adopted Statement 143 on January 1, 2003 and recognized, as the fair value of the asset retirement obligations $281,516. Due to the adoption of Statement 143, we recognized a charge for this cumulative effect of change in accounting principle of $51,834.

In September 2004, the staff of the SEC issued Staff Accounting Bulletin No. 106 (SAB 106) to express the staff's views regarding application of FAS 143, "Accounting for Asset Retirement Obligations," by oil and gas producing companies following the full cost accounting method. SAB 106 addressed the computation of the full cost ceiling test to avoid double-counting asset retirement costs, the disclosures a full cost accounting company is expected to make regarding the impacts of FAS 143, and the amortization of estimated dismantlement and abandonment costs that are expected to result from future development activities. We adopted the accounting and disclosures described in SAB 106 as of the third quarter of 2004 and it did not have a material impact on our financial position or our results of operations.

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123 (Revised 2004), "Share-Based Payment," revising FASB Statement 123, "Accounting for Stock-Based Compensation" and superseding APB Opinion No. 25, "Accounting for Stock Issued to Employees." This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided. FAS 123 (Revised 2004) is effective for interim and annual periods that begin after June 15, 2005 and will be adopted by the Company in the third quarter of 2005. See Note 1 of our financial statements for a disclosure of the effect on net income and earnings per share for the years 2003 and 2004 if we had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended APB Opinion No. 29, "Accounting for Nonmonetary Transactions." FAS 153 requires that nonmonetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. We do not expect this statement to have a material impact on our results of operations or financial condition.

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. We do not expect this statement to have a material impact on our results of operations or financial condition.

Forward-Looking Statements

All statements made in this document and accompanying supplements other than purely historical information are "forward looking statements" within the meaning of the federal securities laws. These statements reflect expectations and are based on historical operating trends, proved reserve positions and other currently available information. Forward looking statements include statements regarding future plans and objectives, future exploration and development expenditures and number and location of planned wells and statements regarding the quality of our properties and potential reserve and production levels. These statements may be preceded or followed by or otherwise include the words "believes," "expects," "anticipates," "intends," "plans," "estimates," "projects" or similar expressions or statements that events "will" or "may" occur. Except as otherwise specifically indicated, these statements assume that no significant changes will occur in the operating environment for oil and gas properties and that there will be no material acquisitions or divestitures except as otherwise described.

The forward-looking statements in this report are subject to all the risks and uncertainties which are described in this document. We may also make material acquisitions or divestitures or enter into financing transactions. None of these events can be predicted with certainty and are not taken into consideration in the forward-looking statements.

For all of these reasons, actual results may vary materially from the forward looking statements and we cannot assure you that the assumptions used are necessarily the most likely. We will not necessarily update any forward looking statements to reflect events or circumstances occurring after the date the statement is made except as may be required by federal securities laws.

There are a number of risks that may affect our future operating results and financial condition. These are described below.

Risks Related to GMX

Our principal shareholders own a significant amount of common stock, giving them significant influence over corporate transactions and other matters.

Ken L. Kenworthy, Jr. (and his wife) and Ken L. Kenworthy, Sr. beneficially own approximately 20.3% and 11.9% respectively, of our outstanding common stock. These shareholders, acting together, have a significant influence on the outcome of shareholder votes, including votes concerning the election of directors, the adoption or amendment of provisions in our certificate of incorporation or bylaws and the approval of mergers and other significant corporate transactions. This concentrated ownership makes it unlikely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business. These factors may also delay or prevent a change in the management or voting control of GMX.

The loss of our President or other key personnel could adversely affect us.

We depend to a large extent on the efforts and continued employment of Ken L. Kenworthy, Jr., our President, and Ken L. Kenworthy, Sr., our Executive Vice President. The loss of the services of either of them could adversely affect our business. In addition, it is a default under our credit agreement if there is a significant change in management or ownership.

We are managed by the members of a single family, giving them influence and control in corporate transactions and their interests may differ from those of other shareholders.

Our executive officers consist of Ken L. Kenworthy, Jr., his father and his brother. Because of the family relationship among members of management, certain employer/employee relationships, including performance evaluations and compensation reviews may not be conducted on a fully arms-length basis as would be the case if the family relationships did not exist. Our board of directors include members unrelated to the Kenworthy family and we expect that significant compensation and other relationship issues between GMX and its management will be reviewed and approved by an appropriate committee of outside directors. However, as the owners of a significant percentage of our common stock, the Kenworthys have significant influence over the current directors.

Our wells produce oil and gas at a relatively slow rate.

We expect that our existing wells and other wells that we plan to drill on our existing properties will produce the oil and gas constituting the reserves associated with those wells over a period of between 15 and 70 years at relatively low annual rates of production. By contrast, wells located in other areas of the United States, such as offshore Gulf coast wells, may produce all of their reserves in a shorter period, for example, four to seven years. Because of the relatively slow rates of production of our wells, our reserves will be affected by long term changes in oil or gas prices or both and we will be limited in our ability to anticipate any price declines by increasing rates of production. We may hedge our reserve position by selling oil and gas forward for limited periods of time but we do not anticipate that, in declining markets, the price of any such forward sales will be attractive.

Our future performance depends upon our ability to obtain capital to find or acquire additional oil and natural gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, resulting eventually in a decrease in oil and natural gas production and lower revenues and cash flows from operations. The business of exploring for, developing or acquiring reserves is capital intensive. Our ability to make the necessary capital investment to maintain or expand our oil and natural gas reserves is limited by our relatively small size. Further, our East Texas joint development partner, PVOG, may propose drilling that would require more capital than we have available from cash flow from operations or our bank credit facility. In such case, we would be required to seek additional sources of financing or limit our participation in the additional drilling. In addition, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil or gas reserves will be encountered.

Our credit history may impair our ability to obtain necessary services.

As a result of our problems in 2002 and 2003 in satisfying past due accounts payable, we may have difficulty in securing trade credit with contractors and others we need to engage to perform services on existing wells or in connection with new drilling even if we have capital available for such purpose.

Estimates of our reserves and associated future net cash flows are dependent upon certain ownership assumptions which may not occur as anticipated.

The estimates of the quantities of our proved undeveloped reserves and the estimated future net revenues from such reserves is based on certain assumptions about our ownership in the underlying properties. As a result of the PVOG participation agreement entered into in December 2003, our ownership interest in proved undeveloped reserves in the Phase I and Phase II acreage has been reduced to reflect PVOG's new ownership position. Our ownership position in wells in Phase II will be reduced as well if PVOG drills two wells in Phase II and our year-end reserve estimates assume that PVOG will complete Phase I and all of Phase II. Our reserve estimates will be increased if PVOG does not complete Phase II.

We have not paid dividends and do not anticipate paying any dividends on our common stock in the foreseeable future.

We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. We do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs and other factors. The declaration and payment of any future dividends is currently prohibited by our credit agreement and may be similarly restricted in the future.

Hedging our production may result in losses or limit potential gains.

Although we do not currently plan to hedge any of our production, we may enter into hedging arrangements in the future. Hedging arrangements expose us to risk of financial loss in some circumstances, including the following:

- production is less than expected;
- the counter-party to the hedging contract defaults on its contact obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

In addition, these hedging arrangements may limit the benefit we would receive from increases in the prices for oil and natural gas. If we choose not to engage in hedging arrangements in the future, we may be more adversely affected by changes in oil and natural gas prices than our competitors who engage in hedging arrangements.

Risks Related to the Oil and Gas Industry

A substantial decrease in oil and natural gas prices would have a material impact on us.

Oil and gas prices are volatile. A decline in prices could adversely affect our financial position, financial results, cash flows, access to capital and ability to grow. Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for the oil and gas we sell. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. The amount we can borrow under our credit facility is subject to periodic redeterminations based on prices specified by our bank at the time of determination. In addition, we may have full-cost ceiling test write-downs in the future if prices fall significantly.

Historically, the markets for oil and gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil and gas prices may result from relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and other factors that are beyond our control, including:

- worldwide and domestic supplies of oil and gas;
- weather conditions;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the availability of pipeline capacity;
- the price and level of foreign imports;
- domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil-producing regions, and
- the overall economic environment.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and gas price movements with any certainty. Declines in oil and gas prices would not only reduce revenue, but could reduce the amount of oil and gas that we can produce economically and, as a result, could have a material adverse effect on our financial condition, results of operations and reserves. Further, oil and gas prices do not necessarily move in tandem. Because approximately 88% of our reserves at December 31, 2004 are natural gas reserves, we are more affected by movements in natural gas prices.

We have encountered difficulty in obtaining equipment and services.

Higher oil and gas prices and increased oil and gas drilling activity, such as those we experienced in 2004, generally stimulate increased demand and result in increased prices and unavailability for drilling rigs, crews, associated supplies, equipment and services. We and PVOG are currently experiencing difficulty obtaining drilling rigs, crews, associated supplies, equipment and services because of a recent increases in prices and in activity. These shortages could also result in increased costs, delays in timing of anticipated development or cause interests in oil and gas leases to lapse. We cannot be certain that we will be able to implement our drilling plans or at costs that will be as estimated or acceptable to us.

Estimating our reserves and future net cash flows is difficult to do with any certainty.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and their values, including many factors beyond our control. The reserve data included in this report represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data, the precision of the engineering and geological interpretation, and judgment. As a result, estimates of different engineers often vary. The estimates of reserves, future cash flows and present value are based on various assumptions, including those prescribed by the Securities and Exchange Commission, and are inherently imprecise. Actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Quantities of proved reserves are estimated based on economic conditions, including oil and natural gas prices in existence at the date of assessment. A reduction in oil and gas prices not only would reduce the value of any proved reserves, but also might reduce the amount of oil and gas that could be economically produced, thereby reducing the quantity of reserves. Our reserves and future cash flows may be subject to revisions, based upon changes in economic conditions, including oil and natural gas prices, as well as due to production results, results of future development, operating and development costs, and other factors. Downward revisions of our reserves could have an adverse affect on our financial condition and operating results.

At December 31, 2004, approximately 65% of our estimated proved reserves (by volume) were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. These reserve estimates include the assumption that we will make significant capital expenditures of $65 million to develop these reserves, including $15 million in 2005. You should be aware that the estimated costs may not be accurate, development may not occur as scheduled and results may not be as estimated.

We may incur write-downs of the net book values of our oil and gas properties that would adversely affect our shareholders' equity and earnings.

The full cost method of accounting, which we follow, requires that we periodically compare the net book value of our oil and gas properties, less related deferred income taxes, to a calculated "ceiling." The ceiling is the estimated after-tax present value of the future net revenues from proved reserves using a 10% annual discount rate and using constant prices and costs. Any excess of net book value of oil and gas properties is written off as an expense and may not be reversed in subsequent periods even though higher oil and gas prices may have increased the ceiling in these future periods. A write-off constitutes a charge to earnings and reduces shareholders' equity, but does not impact our cash flows from operating activities. Future write-offs may occur which would have a material adverse effect on our net income in the period taken, but would not affect our cash flows. Even though such write-offs do not affect cash flow, they can be expected to have an adverse effect on the price of our publicly traded securities.

Operational risks in our business are numerous and could materially impact us.

Our operations involve operational risks and uncertainties associated with drilling for, and production and transportation of, oil and natural gas, all of which can affect our operating results. Our operations may be materially curtailed, delayed or canceled as a result of numerous factors, including:

- the presence of unanticipated pressure or irregularities in formations;
- accidents;
- title problems;
- weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the delivery of equipment.

Also, our ability to market oil and natural gas production depends upon numerous factors, many of which are beyond our control, including:

- capacity and availability of oil and natural gas systems and pipelines;
- effect of federal and state production and transportation regulations; and
- changes in supply of and demand for oil and natural gas.

We do not insure against all potential losses and could be materially impacted by uninsured losses.

Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental accidents, such as oil spills, gas leaks, salt water spills and leaks, ruptures or discharges of toxic gases. If any of these risks occur in our operations, we could experience substantial losses due to:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties; and
- other losses resulting in suspension of our operations.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described above with a general liability limit of $2 million. We do not maintain insurance for damages arising out of exposure to radioactive material. Even in the case of risks against which we are insured, our policies are subject to limitations and exceptions that could cause us to be unprotected against some or all of the risk. The occurrence of an uninsured loss could have a material adverse effect on our financial condition or results of operations.

Governmental regulations could adversely affect our business.

Our business is subject to certain federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters. These laws and regulations have increased the costs of our operations. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production could limit the total number of wells drilled or the allowable production from successful wells which could limit our revenues.

Laws and regulations relating to our business frequently change, and future laws and regulations, including changes to existing laws and regulations, could adversely affect our business.

Environmental liabilities could adversely affect our business.

In the event of a release of oil, gas or other pollutants from our operations into the environment, we could incur liability for personal injuries, property damage, cleanup costs and governmental fines. We could potentially discharge these materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and

- blowouts, cratering and explosions.

In addition, because we may acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage, including historical contamination, caused by such former operators. Additional liabilities could also arise from continuing violations or contamination not discovered during our assessment of the acquired properties.

Competition in the oil and gas industry is intense, and we are smaller and have a more limited operating history than many of our competitors.

We compete with major integrated oil and gas companies and independent oil and gas companies in all areas of operation. In particular, we compete for property acquisitions and for the equipment and labor required to operate and develop these properties. Most of our competitors have substantially greater financial and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for exploratory prospects and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Further, our competitors may have technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, most of our competitors have operated for a much longer time than we have and have demonstrated the ability to operate through industry cycles.

Item 7. FINANCIAL STATEMENTS

Our consolidated financial statements are presented beginning on page F-1 found at the end of this report.

Item 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

On April 29, 2004, our Audit Committee of the Board of Directors approved the dismissal of KPMG, LLP ("KPMG") as our independent public accountant. On the same day, the Audit Committee approved Smith, Carney & Co., p.c. ("Smith Carney") as our independent public accountant for the year 2004.

KPMG's audit report on our consolidated financial statements as of and for each of the years ended December 31, 2003 and 2002 did not contain an adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principals, except as follows:

KPMG's report on our consolidated financial statements for the year ended December 31, 2002 contained a separate paragraph stating that "The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note L to the financial statements, the Company is not in compliance with certain of its debt covenants and has a significant working capital deficiency that raise substantial doubt about the Company's ability to continue operating as a going concern. Management's plans in regard to these matters are also described in Note L. The financial statements do not include any adjustments that might result from the outcome of this uncertainty."

KPMG's report on our consolidated financial statements for the year ended December 31, 2003 contained a separate paragraph stating that "As discussed in Note A to the consolidated financial statements, GMX Resources Inc. changed its method of accounting for asset retirement obligations in 2003."

During the years ended December 31, 2003 and 2002, and through April 29, 2004, there were no disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure which, if not resolved to KPMG's satisfaction, would have caused them to make reference to the subject matter in connection with their opinion on our consolidated financial statements for such years.

During the years ended December 31, 2003 and 2002 and through April 29, 2004, we did not consult Smith Carney with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or any matters or reportable events as set forth in Items 304(a)(2)(i) and (ii) of Regulation S-K.

Item 8A. CONTROLS AND PROCEDURES

Our Principal Executive Officer and Principal Financial Officer have reviewed and evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rule 240.13a-14(c)) as of the end of the period covered by this report. Based on that evaluation, the Principal Executive Officer and the Principal Financial Officer have concluded that our current disclosure controls and procedures are effective to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

Item 8B. OTHER INFORMATION

None

PART III

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

The directors and executive officers of the Company are as follows:

Name	Age	Position Currently Held
Ken L. Kenworthy, Jr.	48	President, Chief Executive Officer and Director
Ken L. Kenworthy, Sr.	69	Executive Vice President Secretary, Treasurer, Chief Financial Officer and Director
T.J. Boismier	70	Director
Steven Craig	48	Director
Jon W. "Tucker" McHugh	60	Director
Kyle Kenworthy	43	Vice President -- Land

The following is a brief description of the business background of each of our directors and executive officers.

Ken L. Kenworthy, Jr. is a co-founder of GMX and has been President and a director since the Company's inception in 1998. In 1980, he founded OEXCO Inc., a privately held oil and gas company, which he managed until 1995 when its properties were sold for approximately $13 million. During this period OEXCO operated 300 wells and drilled and discovered seven fields and dozens of new zones. During this same period, he formed and managed a small gas gathering system. From 1995 until he founded GMX in 1998, Mr. Kenworthy was a private investor. From 1980 to 1984, he was a partner in Hunt-Kenworthy Exploration which was formed to share drilling and exploration opportunities in different geological regions. Prior to 1980, he held various geology positions with Lone Star Exploration, Cities Service Gas Co., Nova Energy, and Berry Petroleum Corporation. He also served as a director of Nichols Hills Bank, a commercial bank in Oklahoma City, Oklahoma for ten years before it was sold in 1996 to what is now Bank of America. He is a member of the American Association of Petroleum Geologists and Oklahoma City Geological Society.

Ken L. Kenworthy, Sr. is a co-founder of GMX and has been Executive Vice President, Chief Financial Officer and a director since the Company's inception in 1998. From 1993 to 1998, he was principal owner and Chairman of Granita Sales Inc., a privately-held frozen beverage manufacturing distribution company. Prior to that time, he held various financial positions with private and public businesses, including from 1970 to 1984, as vice president, secretary-treasurer, chief financial officer and a director of CMI Corporation, a New York Stock Exchange listed company which manufactures and sells road-building equipment. He has held several accounting industry positions including past president of the Oklahoma City Chapter National Association of Accountants, past vice president of the National Association of Accountants and past officer and director of the Financial Executives Institute.

T. J. Boismier is founder, President and Chief Executive Officer of T. J. Boismier Co., Inc., a privately held mechanical contracting company in Oklahoma City, Oklahoma, which designs and installs plumbing, heating, air conditioning and utility systems in commercial buildings, a position he has held since 1961. He became a director in February 2001 simultaneously with the completion of the Company's initial public offering.

Steven Craig is the Chief Energy Analyst for Elliott Wave International, a securities market research and advisory company located in Gainesville, Georgia, which is one of the world's largest providers of market research and technical analysis. As Chief Energy Analyst, Mr. Craig provides in-depth analysis and price forecasts of the major NYMEX and IPE energy markets to an institutional clientele that spans the gamut of the energy industry. Prior to joining Elliott Wave International in January 2001, he provided risk management services to Central and South West, one of the largest natural gas consumers in the U.S. prior to its merger with American Electric Power in June 2000 and independent oil and gas producer Kerr-McGee. He became a director in August 2001.

Kyle Kenworthy became Vice President of Land for the Company in March, 1999. From 1997 until he joined the Company, he was an independent petroleum landman, performing contract land services for other oil and gas companies, and from 1992 to 1997 he was an independent real estate investor and manager. Prior to that time, he was employed by H&K Exploration and OEXCO Inc. in various geological, accounting and land management positions. Over a 12 year period at OEXCO, Mr. Kenworthy helped structure and managed an aggressive drilling program in Oklahoma City and surrounding areas for over 300 company operated wells.

Jon W. "Tucker" McHugh became a director of the Company in January 2005. Since 1997, Mr. McHugh has been Senior Vice President Commercial Lending and head of marketing at First Commercial Bank, Edmond, Oklahoma.

Ken Kenworthy, Sr. is the father of Ken Kenworthy, Jr. and Kyle Kenworthy.

Significant Employees

Keith Leffel, age 55, has been employed as our natural gas marketer and pipeline operations manager since November 2001. Since 1986, Mr. Leffel formed and operated GKL Energy Services Company, a company that assists producers with gas marketing services.

Rick Hart, Jr. a, petroleum engineer, age 47, was hired in January 2004 as Operations Manager. He has 24 years of experience in all aspects of operations, including specific expertise in drilling, completion and production in the East Texas reservoirs. He worked with Focus Energy for nine years and had responsibility for 319 producing wells.

Consultant

In March 2004, the Company engaged Donald Duke to provide engineering, corporate management and business development consulting assistance and advisory services. Mr. Duke is president of Duke Resources Co., LLC, an independent oil and gas production and consulting firm. He has over 32 years of energy industry management and engineering experience having served as senior management positions with TGX Corporation, Hadson Petroleum, Santa Fe Minerals and Andover Oil Company.

Terms

Each director is elected to hold office until the next annual meeting of shareholders or until his successor is duly elected and qualified. The executive officers and significant employees are appointed by the Board of Directors and serve at its discretion.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities and Exchange Act of 1934 requires our directors and executive officers and persons who beneficially own more than 10% of our common stock to file reports of ownership and changes in ownership of our common stock with the Securities and Exchange Commission. We are required to disclose delinquent filings of reports by such persons.

Based on a review of the copies of such reports and amendments thereto received by us, or written representations that no filings were required, we believe that all Section 16(a) filing requirements applicable to our executive officers, directors and 10% shareholders were met during 2004, except for one late filing by Karen M. Kenworthy who inadvertently filed a Form 4 to report a sale of shares one day late.

Audit Committee Matters

During 2004, we had a standing audit committee consisting of Messrs. Boismier and Craig, both of whom have been determined by the Board to be independent as required by applicable rules of the Securities and Exchange Commission and The NASDAQ Stock Market. Neither of these individuals qualify as a "financial expert" as contemplated by the rules of the Securities and Exchange Commission. These individuals were appointed to our audit committee before the adoption of the financial expert rules. In January 2005, Mr. McHugh was elected to the Board and the audit committee. The Board has determined that Mr. McHugh is independent as required by applicable rules of the Securities and Exchange Commission and The NASDAQ Stock Market and qualifies as a “financial expert.”

Code of Ethics

We have adopted a Code of Business Conduct and Ethics ("Code") that is applicable to all of our officers, directors and employees, including our principal executive, financial and accounting officers. A copy of the Code is filed as an exhibit to this report.

Item 10. EXECUTIVE COMPENSATION

The following table sets forth information with respect to compensation received by our chief executive officer and our other executive officers.

Summary Compensation Table

		Annual Compensation			
Name and Principal Position	Year	Salary	Bonus	Other Annual Compensation	All Other Compensation[1]
Ken L. Kenworthy, Jr.	2002	$175,000	$30,000	---	$ 8,385
President and Chief Executive	2003	157,500	---	---	---
Officer	2004	166,667	20,000	---	---
Ken L. Kenworthy, Sr.	2002	175,000	30,000	---	8,385
Executive Vice President, Secretary,	2003	157,500	---	---	---
Treasurer and Chief Financial Officer	2004	166,667	20,000	---	---
Kyle Kenworthy	2002	72,000	---	---	5,232
Vice President--Land	2003	72,000	1,000	---	2,599
	2004	74,880	4,000	---	2,599

(1) All Other Compensation includes amounts contributed by *GMX* for the account of the named individual to *GMX's* 401(k) plan and a gasoline allowance for Kyle Kenworthy.

The following table shows option grants to the named executive officers in 2004.

Option Grants in Last Fiscal Year

Name	Number of Shares of Common Stock Underlying Options Granted	% of Total Options Granted to Employees in Fiscal Year	Exercise or Base Price ($/share) [1]	Expiration Date
Kyle Kenworthy	5,000	2.5%	$ 3.00	01-12-2014
	5,000	2.5%	$ 6.10	12-13-2014

(1) These options became exercisable at the rate of 25% per year as long as the optionee remains employed.

The following table reflects options exercised during 2004 or outstanding at year-end for the named executive officers.

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

			Number of Securities Underlying Unexercised Options at December 31, 2004		Value of Unexercised In-the-Money Options at December 31, 2004	
Name	Shares Acquired on Exercise	Value Realized	Exercisable	Unexercisable	Exercisable	Unexercisable
Kyle Kenworthy	N/A	N/A	15,000	15,000	$22,088	$2,463

Compensation of Directors

Nonemployee directors, T. J. Boismier, Steven Craig and Jon Tucker McHugh receive $1,000 for each board and $500 for each committee meeting which they attend. We have also granted options to our nonemployee directors. Mr. Boismier received an option on February 12, 2001 to purchase 10,000 shares of common stock at a price of $8.00 per share (the initial public offering price of GMX's units) which will vest at a rate of 25% per year for each year of continued service. Mr. Boismier received an additional option on March 16, 2001 (when GMX's units split into common stock and warrants) to purchase 5,000 shares of common stock at a price of $4.03 per share (the market price of our common stock on the date of grant), also vesting at 25% per year for each year of continued service. Mr. Craig received an option on September 10, 2001 to purchase 10,000 shares of common stock at a price of $5.00 which also will vest at a rate of 25% per year for each year of continued service. No options were granted in 2002 or 2003. On January 12, 2004, Mr. Boismier and Mr. Craig each received options to purchase 10,000 shares of common stock at $3.00 per share vesting at 25% per year of each year of continued service. On December 13, 2004, Mr. Boismier and Mr. Craig also received 10,000 additional options at $6.10. Mr. McHugh received an option for 10,000 shares at $8.00 per share on the date he was elected a director, January 20, 2005.

Item 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERSHIP AND MANAGEMENT

The following table sets forth certain information regarding the beneficial ownership of our common stock as of March 22, 2005, 2005, by (i) each person or group of affiliated persons known to be the beneficial owner of more than 5% of our outstanding common stock; (ii) each of our directors; (iii) each of our executive officers; and (iv) all of our directors and executive officers as a group.

As of March 22, 2005, there were 8,201,587 shares of common stock outstanding. Except as otherwise listed below, each named beneficial owner has sole voting and investment power with respect to the shares listed.

Beneficial Owner	Number of Shares	Percent of Total
Ken L. Kenworthy, Jr. (1) (2)	902,018	11.1%
Karen Kenworthy(2)(6)	744,990	9.2%
Ken L. Kenworthy, Sr.(2)	967,324	11.9%
Newton Family Group(7)	900,000	11.1%
T. J. Boismier(3)	22,500	*
Steven Craig(4)	10,000	*
Kyle Kenworthy(5)	18,750	*
Jon W. McHugh	0	*
All executive officers and directors as a group (6 persons)	1,920,592	23.4%

* Less than 1%.

(1) Shares owned by Mr. Kenworthy, Jr. exclude 744,990 shares owned by his wife as to which he disclaims beneficial ownership.

(2) The business address of Messrs. Kenworthy, Jr. and Kenworthy, Sr. and Karen M. Kenworthy is 9400 North Broadway, Oklahoma City, Oklahoma 73114.

(3) Includes 2,500 shares which Mr. Boismier has the right to acquire upon exercise of Class A warrants and 20,000 shares he has the right to acquire on exercise of options exercisable within 60 days.

(4) Includes 10,000 shares which Mr. Craig has the right to acquire on exercise of options exercisable within 60 days.

(5) Includes 18,750 shares which Mr. Kenworthy has the right to acquire on exercise of options exercisable within 60 days.

(6) Shares owned by Karen Kenworthy exclude 902,018 shares owned by her husband Ken L. Kenworthy, Jr., as to which she disclaims beneficial ownership.

(7) This ownership information is based on information provided by the Newton Family Group. The Newton Family Group consists of William C. Newton and Gloria A. Newton, husband and wife, Newton Discretionary Trust, as to which William C. Newton is the sole trustee; and Newton Investment Partners, as to which William C. Newton is the managing partner. William C. Newton and Gloria A. Newton have beneficial ownership of 900,000 shares, which includes 775,000 shares beneficially owned by Newton Investment Partners and 100,000 shares that may be acquired upon the exercise of warrants held by Newton Investment Partners. The business address of the Newton Family Group is c/o Newton Corporation, 660 East Broadway, Jackson Hole, Wyoming 83001.

Item 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

Item 13. EXHIBITS

For a list of Exhibits, see the Exhibit Index immediately preceding the Exhibits filed with this report.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table sets forth the fees billed by our independent auditor, Smith, Carney & Co., p.c. for 2004, and KPMG for the year 2003:

	Fees Billed	
Type	**2003**	**2004**
Audit fees	$ 65,000	$ 50,000
Audit related fees	---	---
Tax fees	---	15,000
All other fees	---	9,505
Total	$ 65,000	$ 74,505

The Audit Committee pre-approved all audit and non-audit services, if any, performed by our independent auditors. All other fees in 2004 related to non-prohibited consulting services provided by our independent auditors in 2004.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GMX RESOURCES INC.

Dated: March 31, 2005

By: /s/ Ken L. Kenworthy, Jr.
Ken L. Kenworthy, Jr., President

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

Signatures	Title	Date
/s/ Ken L. Kenworthy, Jr. Ken L. Kenworthy, Jr.	President and Director (Principal Executive Officer)	March 31, 2005
/s/ Ken L. Kenworthy, Jr. Ken L. Kenworthy, Sr.	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	March 31, 2005
/s/ T. J. Boismier T. J. Boismier	Director	March 31, 2005
/s/ Steven Craig Steven Craig	Director	March 31, 2005
/s/ Jon W. McHugh Jon W. McHugh	Director	March 31, 2005

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
GMX Resources Inc.

We have audited the accompanying consolidated balance sheets of GMX Resources Inc. and subsidiaries as of December 31, 2004 and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with auditing 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 misstatements. 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 managements, as well as evaluating the overall financial statement presentation. We believe that our audit provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GMX Resources Inc. and subsidiaries as of December 31, 2004 and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

Smith, Carney & Co., p.c.

Oklahoma City, Oklahoma
February 18, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders
GMX Resources Inc.:

We have audited the accompanying consolidated balance sheets of GMX Resources Inc. and subsidiaries as of December 31, 2003 and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of GMX Resources Inc. and subsidiaries as of December 31, 2003 and the results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

As discussed in Note A to the consolidated financial statements, GMX Resources Inc. changed its method of accounting for asset retirement obligations in 2003.

KPMG LLP

Oklahoma City, Oklahoma
April 6, 2004

GMX Resources Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2003	December 31, 2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 637,522	$ 862,546
Accounts receivable—interest owners	299,442	96,248
Accounts receivable—oil and gas revenues	432,844	1,501,073
Inventories	235,004	204,442
Prepaid expenses and other current assets	11,608	108,447
Total current assets	1,616,420	2,772,756
OIL AND GAS PROPERTIES, AT COST, BASED ON THE FULL COST METHOD OF ACCOUNTING FOR OIL AND GAS PROPERTIES	32,449,096	42,452,970
Less accumulated depreciation, depletion, and amortization	(4,788,779)	(6,496,210)
	27,660,317	35,956,760
OTHER PROPERTY AND EQUIPMENT	3,200,345	3,515,422
Less accumulated depreciation	(991,889)	(1,308,358)
	2,208,456	2,207,064
OTHER ASSETS	16,013	54,883
TOTAL ASSETS	$ 31,501,206	$ 40,991,463
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,134,500	$ 2,321,517
Accrued expenses	64,887	134,718
Accrued interest	29,703	---
Revenue distributions payable	285,382	274,862
Current portion of long-term debt	1,060,000	433,933
Total current liabilities	2,574,472	3,165,030
LONG-TERM DEBT, LESS CURRENT PORTION	5,630,000	3,328,361
OTHER LIABILITIES	678,169	2,091,216
SHAREHOLDERS' EQUITY:		
Preferred stock, par value $.01 per share, 10,000,000 shares authorized; none issued;		
Common stock, par value $.001 per share – authorized 50,000,000 shares; issued and outstanding 6,575,000 shares in 2003 and 8,053,539 shares in 2004	6,575	8,054
Additional paid-in capital	20,959,973	29,305,012
Retained earnings	1,652,017	3,093,790
Total shareholders' equity	22,618,565	32,406,856
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 31,501,206	$ 40,991,463

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,	
	2003	**2004**
REVENUE		
Oil and gas sales	$ 5,367,370	$ 7,689,882
Interest income	2,592	14,498
Other income	18,832	129,330
Total revenue	5,388,794	7,833,710
EXPENSES		
Lease operations	850,034	1,261,109
Production and severance taxes	384,069	518,721
Depreciation, depletion and amortization	1,549,678	2,043,485
Interest	439,313	558,504
General and administrative	1,578,865	1,985,912
Total expenses	4,801,959	6,367,731
Income before income taxes	586,835	1,465,979
INCOME TAXES	---	24,206
Net income before cumulative effect of a change in accounting principle	$ 586,835	$ 1,441,773
Cumulative effect of a change in accounting principle	(51,834)	---
Net income	$ 535,001	$ 1,441,773
EARNINGS PER SHARE—Before Cumulative Effect	$ 0.09	$ 0.19
EARNINGS (LOSS) PER SHARE—Cumulative Effect	(0.01)	---
EARNINGS PER SHARE—Basic and Diluted	$ 0.08	$ 0.19
WEIGHTED AVERAGE COMMON SHARES – Basic	6,560,000	7,396,880
WEIGHTED AVERAGE COMMON SHARES – Diluted	6,560,000	7,491,778

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statement of Changes in Shareholders' Equity
Years Ended December 31, 2003 and 2004

	COMMON STOCK SHARES	COMMON STOCK AMOUNT	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL SHAREHOLDERS' EQUITY
BALANCE AT DECEMBER 31, 2002	6,550,000	$ 6,550	$ 20,905,197	$ 1,117,016	$ (421,300)	$ 21,607,463
Compensation from option grant	---	---	29,801	---	---	29,801
Options exercised	25,000	25	24,975	---	---	25,000
Adjustment from derivative losses reclassified into oil and gas sales	---	---	---	---	438,400	438,400
Change in fair value of derivative instruments	---	---	---	---	(17,100)	(17,100)
Net income	---	---	---	535,001	---	535,001
Total comprehensive income	---	---	---	---	---	956,301
BALANCE AT DECEMBER 31, 2003	6,575,000	$ 6,575	$ 20,959,973	$ 1,652,017	$ ---	22,618,565
Options Exercised	15,000	15	14,985	---	---	15,000
Redeemed & Cancelled Warrants	---	---	(118,712)	---	---	(118,712)
Warrants Granted	---	---	257,250	---	---	257,250
Warrants Exercised	163,540	164	177,398	---	---	177,562
Shares Issued	1,300,000	1,300	8,014,118	---	---	8,015,418
Net income	---	---	---	1,441,773	---	1,441,773
BALANCE AT DECEMBER 31, 2004	8,053,540	$ 8,054	$ 29,305,012	$ 3,093,790	$ ---	$ 32,406,856

See accompanying notes to consolidated financial statements.

GMX Resources Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Year Ended December 31, 2003	2004
CASH FLOWS DUE TO OPERATING ACTIVITIES		
Net income	$ 535,001	$ 1,441,773
Adjustments to reconcile net income to net cash provided by operating activities:		
Compensation-stock options	29,801	---
Depreciation, depletion, and amortization	1,549,678	2,043,485
Cumulative effect of change in accounting principle, net of tax	51,834	---
Accretion of asset retirement obligation	22,521	24,323
Amortization of loan fees	---	326,762
Decrease (increase) in:		
Accounts receivable	84,188	(865,035)
Inventory and prepaid expenses	1,701	(431,908)
Other assets	41,633	---
Increase (decrease) in:		
Accounts payable	(1,292,215)	1,187,017
Accrued expenses and other liabilities	112,615	40,128
Revenue distributions payable	(122,467)	(58,067)
Cash provided by operating activities	1,014,290	3,708,478
CASH FLOWS DUE TO INVESTING ACTIVITIES		
Additions to oil and gas properties	(236,617)	(8,567,690)
Purchase of property and equipment	---	(334,577)
Proceeds from sale of oil and gas properties	700,932	---
Cash provided by (used in) investing activities	464,315	(8,902,267)
CASH FLOWS DUE TO FINANCING ACTIVITIES		
Advance on borrowings	---	3,872,457
Payments on debt	(1,410,000)	(6,800,162)
Proceeds from sale of stock	25,000	8,346,518
Cash provided by (used in) financing activities	(1,385,000)	5,418,813
NET INCREASE IN CASH AND CASH EQUIVALENTS	93,605	225,024
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	543,917	637,522
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 637,522	$ 862,546
CASH PAID FOR INTEREST	$ 376,585	$ 261,445
CASH PAID FOR INCOME TAXES	$ ---	$ 24,206

See accompanying notes to consolidated financial statements.

NOTE A--SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION: The consolidated financial statements include the accounts of GMX Resources Inc. (the "Company or GMX") and its wholly owned subsidiaries, Endeavor Pipeline, Inc. and Expedition Natural Resources, Inc. Endeavor Pipeline, Inc. owns and operates natural gas gathering facilities in East Texas. Expedition Natural Resources, Inc. owns undeveloped leases, primarily in East Texas. All significant intercompany accounts and transactions have been eliminated. Accounting policies used by the Company reflect industry practices and conform to accounting principles generally accepted in the United States of America. The more significant of such policies are briefly described below.

ORGANIZATION: The Company was formed in January 1998. In February 1998, the Company purchased, for approximately $6,000,000, oil and gas properties and commenced operations. The Company is primarily engaged in acquisition, exploration, and development of properties for the production of crude oil and natural gas in Louisiana, New Mexico, and Texas.

CASH AND CASH EQUIVALENTS: GMX considers all highly liquid investments with maturities of three months or less at the time of purchase to be cash equivalents.

INVENTORIES: Inventories consist of lease and well equipment and crude oil on hand. The Company plans to utilize the lease and well equipment in its ongoing operations and it is carried at the lower of cost or market. Treated and stored crude oil inventory on hand at the end of the year is valued at the lower of cost or market.

PROPERTY AND EQUIPMENT: The Company follows the full cost method of accounting for its oil and gas properties. Accordingly, all costs incidental to the acquisition, exploration and development of oil and gas properties, including costs of undeveloped leasehold, dry holes and leasehold equipment are capitalized. Net capitalized costs are limited to the estimated future net revenues, discounted at 10% per annum, from proved oil, natural gas, and natural gas liquid reserves. Capitalized costs are depleted by an equivalent unit-of-production method, converting oil to gas at the ratio of one barrel of oil to six thousand cubic feet of natural gas. No gain or loss is recognized upon disposal of oil and gas properties unless such disposal significantly alters the relationship between capitalized costs and proved reserves. Revenues from services provided to working interest owners of properties in which GMX also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and gas properties.

The December 2003 sale of an interest in East Texas properties did not result in a gain or loss. All proceeds from the sale were applied to the full cost pool.

Depreciation and amortization of other property and equipment, including leasehold improvements, are provided using the straight-line method based on estimated useful lives from five to 10 years.

Pipeline and gathering system assets and other long-lived assets are periodically assessed to determine if circumstances indicate that the carrying amount of an asset may not be recoverable in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This statement requires (a) recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and (b) measurement of an impairment loss as the difference between the carrying amount and fair value of the asset.

LOAN FEES: Included in other assets are costs associated with long-term debt. These costs are being amortized over the life of the loan using a method that approximates the interest method.

REVENUE AND ROYALTY DISTRIBUTIONS PAYABLE: For certain oil and natural gas properties GMX receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds applicable to other revenue and royalty owners are reflected as revenue distributions payable in the accompanying balance sheets. GMX accrues revenue for only its net interest in its oil and gas properties.

REVENUE RECOGNITION AND NATURAL GAS BALANCING: Oil and gas revenues are recognized when sold. During the course of normal operations, the Company and other joint interest owners of natural gas reservoirs will take more or less than their respective ownership share of the natural gas volumes produced. These volumetric imbalances are monitored over the lives of the wells' production capability. If an imbalance exists at the time the wells' reserves are depleted, cash settlements are made among the joint interest owners under a variety of arrangements.

The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company's excess takes of natural gas volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. There are no significant imbalances as of December 31, 2003 or 2004.

CAPITALIZED INTEREST: Interest of $20,729 was capitalized related to the unproved properties that were not being currently depreciated, depleted, or amortized and on which development activities were not in progress in 2004.

INCOME TAXES: The Company accounts for income taxes using the asset and liability method. Under the asset and liability method, deferred tax assets and liabilities are recognized at the enacted tax rates for the future tax consequences attributable to differences between the financial carrying amounts of existing assets and liabilities and the respective tax bases and tax operating losses and tax credit carryforwards. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

HEDGING AND RISK MANAGEMENT ACTIVITIES: The Company has periodically entered into oil and gas price swaps to manage its exposure to oil and gas price volatility. The instruments are usually placed with counterparties that the Company believes are minimal credit risks. The oil and gas reference prices upon which the risk management instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

GENERAL AND ADMINISTRATIVE EXPENSES: General and administrative expenses are reported net of amounts allocated to working interest owners of the oil and gas properties operated by the Company and net of amounts capitalized pursuant to the full cost method of accounting.

USE OF ESTIMATES: The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the use of estimates and assumptions that affect the amounts reported. The actual results could differ from those estimates, including useful lives of property and equipment, oil and gas reserve quantities, and expenses associated with asset retirements.

FINANCIAL INSTRUMENTS: The Company's financial instruments consist of cash, accounts receivable, accounts payable, accrued expenses, accrued interest, revenue distributions payable, long-term debt, and oil and natural gas price swap and options agreements. Fair value of non-derivative financial instruments approximates carrying value due to the short-term nature of these instruments. Since the interest rate on the long-term debt reprices frequently, the fair value of the long-term debt approximates the carrying value.

BASIC EARNINGS PER SHARE AND DILUTED EARNINGS PER SHARE: Basic earnings per share ("EPS") of common stock have been computed on the basis of the weighted average number of shares outstanding during each period. The diluted EPS of common stock includes the effect of outstanding stock options and warrants which are dilutive.

The table below reflects the amount of options not included in the diluted EPS calculation above, as they were antidilutive.

	2003	2004
Options excluded from dilution calculation	64,000	41,000
Range of exercise prices	\$3.50 - \$8.00	\$5.00 - \$8.00
Weighted average exercise price	\$6.00	\$6.75

STOCK OPTIONS: The Company applies the intrinsic value-based method of accounting for its fixed plan stock options, as described by Accounting Principles Board Opinion No. 25 "Accounting for Stock Issued to Employees," and related interpretations. As such, compensation expense would be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price of the option. SFAS 123, "Accounting for Stock-Based Compensation," established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by Statement 123, GMX has elected to continue to apply the intrinsic value based method of accounting described above.

Stock option activity for the year ended December 31, 2003 and 2004, which includes in 2003 shares granted to consultant, is as follows:

	Number of shares		Weighted average exercise price
Balance as of December 31, 2002	140,000	$	5.65
Granted	100,000		1.00
Exercised	(25,000)		1.00
Forfeited	(76,000)		5.62
Expired	---		---
Balance as of December 31, 2003	139,000	$	5.69
Granted	190,000		3.83
Exercised	(15,000)		1.00
Forfeited	---		---
Expired	---		---
Balance as of December 31, 2004	314,000	$	3.67

At December 31, 2004, the range of exercise prices and weighted-average remaining contractual life of outstanding options was $1.00 to $8.00 and ten years, respectively.

At December 31, 2004, the number of options exercisable was 314,000 and the weighted-average exercise price of those options was $3.67.

The Company applied APB Opinion No. 25 in accounting for its plan and accordingly, no compensation cost has been recognized for its stock options granted to employees in the financial statements. Had the Company determined compensation cost based on the fair value at the grant date for its stock options under Statement 123, the Company's results would have been reduced by the pro forma amounts indicated below.

		2003		2004
Net earnings as reported	$	535,001	$	1,441,773
Add: Stock-based compensation recognized		29,801		---
Deduct: Pro forma stock-based compensation, net of tax		(79,081)		(316,085)
Pro forma net earnings	$	485,721	$	1,125,689
Pro forma earnings per share – basic	$	0.07		0.15
Pro forma earnings per share – diluted	$	0.07		0.15

For the January 2004 options, fair value was determined using the Black Scholes option pricing model with the following assumptions: expected dividend yield of 0%, risk-free interest rate of 1%, expected volatility of 116%, and an expected term of 10 years. For the December 2004 options, fair value was determined using the Black-Scholes option pricing model with the following assumptions: expected dividend yield of 0%, risk-free interest rate of 1%, expected volatility of 137%, and an expected term of 10 years.

COMMITMENTS AND CONTINGENCIES: Liabilities for loss contingencies arising from claims, assessments, litigation, or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated.

Environmental expenditures are expensed or capitalized in accordance with accounting principles generally accepted in the United States of America. Liabilities for these expenditures are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated.

RECLASSIFICATIONS: Certain prior year balances have been reclassified to conform to the current year presentation.

SEGMENT INFORMATION: GMX manages its business by country, which results in one operating segment during each of the years ended December 31, 2003 and 2004.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS: In June 2001, FASB Statement No. 143, Accounting for Asset Retirement Obligations, was issued. Statement 143 required the Company to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Company also recorded a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Company was required to adopt Statement 143 on January 1, 2003 and recognized, as the fair value of the asset retirement obligations, $281,516. Due to the adoption of Statement 143, the Company recognized a charge in 2003, for this cumulative effect of change in accounting principle, of $51,834.

Below is a reconciliation of the beginning and ending aggregate carrying amount of the Company's asset retirement obligations.

Balance as of December 31, 2002	$ ---
Initial adoption entry	281,516
Liabilities incurred	---
Liabilities settled	---
Accretion expense	22,521
Balance as of December 31, 2003	$ 304,037
Liabilities incurred	40,493
Liabilities settled	(249,867)
Accretion expense	24,323
Increase due to revisions (1)	1,645,645
Balance as of December 31, 2004	$ 1,764,631

(1) Revisions were due to the increase in market prices for services related to plugging a well, the current inflation rate and interest rate.

In addition, on a pro forma basis as required by SFAS No. 143, if the Company had applied the provisions of SFAS No. 143 as of January 1, 2002, the amount of asset retirement obligations would have been approximately $250,000, with no material impact on results of operations.

In September 2004, the staff of the SEC issued Staff Accounting Bulletin No. 106 (SAB 106) to express the staff's views regarding application of FAS 143, "Accounting for Asset Retirement Obligations," by oil and gas producing companies following the full cost accounting method. SAB 106 addressed the computation of the full cost ceiling test to avoid double-counting asset retirement costs, the disclosures a full cost accounting company is expected to make regarding the impacts of FAS 143, and the amortization of estimated dismantlement and abandonment costs that are expected to result from future development activities. We adopted the accounting and disclosures described in SAB 106 as of the third quarter of 2004 and did not have a material impact on our financial position of the Company, or our results of operations.

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123 (Revised 2004), "Share-Based Payment," revising FASB Statement 123, "Accounting for Stock-Based Compensation" and superseding APB Opinion No. 25, "Accounting for Stock Issued to Employees." This statement requires a public entity to measure the cost of services provided by employees and directors received in exchange for an award of equity instruments, including stock options, at a grant-date fair value. The fair value cost is then recognized over the period that services are provided. FAS 123 (Revised 2004) is effective for interim and annual periods that begin after June 15, 2005 and will be adopted by the Company in the third quarter of 2005. See "Stock Options" above for a disclosure of the effect on net income and earnings per share for the years 2003 and 2004 if we had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

The FASB issued Statement on Financial Accounting Standards No. 153, "Exchanges of Productive Assets," in December 2004 that amended APB Opinion No. 29, "Accounting for Nonmonetary Transactions." FAS 153 requires that nonmonetary exchanges of similar productive assets are to be accounted for at fair value. Previously these transactions were accounted for at book value of the assets. This statement is effective for nonmonetary transactions occurring in fiscal periods beginning after June 15, 2005. We do not expect this statement to have a material impact on results of operations or financial condition.

In November 2004, the FASB issued Statement on Financial Accounting Standards No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which clarifies the types of costs that should be expensed rather than capitalized as inventory. The provisions of FAS 151 are effective for years beginning after June 15, 2005. We do not expect this statement to have a material impact on results of operations or financial condition.

NOTE B--PROPERTY AND EQUIPMENT

Property and equipment included the following:

	December 31, 2003	December 31, 2004
Oil and gas properties:		
Subject to amortization	$ 31,219,309	$ 41,893,564
Not subject to amortization:		
Acquired in 2004	---	447,786
Acquired in 2003	57,565	---
Acquired in 2002	76,829	76,829
Acquired in 2001	853,258	34,791
Acquired in 2000	93,195	---
Acquired in 1999	---	---
Acquired in 1998	148,940	---
Accumulated depreciation, depletion, and amortization	(4,788,779)	(6,496,210)
Net oil and gas properties	27,660,317	35,956,760
Other property and equipment	3,200,345	3,515,422
Less accumulated depreciation	(991,889)	(1,308,358)
Net other property and equipment	2,208,456	2,207,064
Property and equipment, net of accumulated Depreciation, depletion, and amortization	$ 29,868,773	$ 38,163,824

Depreciation, depletion, and amortization of property and equipment consisted of the following components:

	For The Year Ended December 31, 2003	For The Year Ended December 31, 2004
Depreciation, depletion, and amortization of oil and gas properties	$ 1,214,361	$ 1,707,431
Depreciation of other property and equipment	335,317	336,054
Total	$ 1,549,678	$ 2,043,485

NOTE C--LONG-TERM DEBT

	December 31, 2003	December 31, 2004
Note payable to bank, maturity date of September, 2006, bearing a variable interest rate (5.00% and 5.25% as of December 31, 2003 and 2004, respectively) collateralized by producing oil and gas properties	$ 6,690,000	$ 1,849,837
Joint venture partner project (financing, non-recourse, no interest rate)	---	1,912,457
	6,690,000	3,762,294
Current portion	1,060,000	433,933
Long Term	$ 5,630,000	$ 3,328,361

Maturities of long-term debt are as follows:

Year	Amount
2005	$ 433,934
2006	2,558,173
2007	770,187
	$ 3,762,294

2000 Credit Facility

On October 31, 2000, the Company entered into a new secured credit facility, which replaced a prior credit facility. The new credit facility provides for a line of credit of up to $15,000,000 (the "Commitment"), subject to a borrowing base which is based on a periodic evaluation of oil and gas reserves which is reduced monthly to account for production ("Borrowing Base"). The amount of credit available at any one time under the credit facility is the lesser of the Borrowing Base or the amount of the Commitment. Borrowings bear interest at the prime rate up to plus 1% depending on the level of borrowings relative to the Borrowing Base. The credit facility requires payment of an annual facility fee equal to 1/2% on the unused amount of the Borrowing Base. The Company is obligated to make principal payments if the amount outstanding would exceed the Borrowing Base. Borrowings under the credit agreement are secured by substantially all of the Company's oil and gas properties. The amount of this Borrowing Base has been adjusted from time to time. The credit facility has been amended on several occasions to waive non-payment default or to extend the maturity, most recently in June to extend the maturity to September 1, 2006. On October 25, 2004, the bank increased the Borrowing Base to $10,000,000, with monthly commitment reduction of $120,000. At December 31, 2004, the Company had borrowed $1,849,837 under the credit facility.

The credit facility contains various affirmative and restrictive covenants. These covenants, among other things, prohibit additional indebtedness, sales of assets, mergers and consolidations, dividends and distributions, changes in management and require the maintenance of various financial ratios.

Subordinated Debt

In January 2004, the Company raised $1 million from the sale of 11% senior subordinated notes due January 31, 2007 and five-year detachable warrants to purchase 175,000 shares of common stock for $1.50 per share. The price of the Company's common shares as of that date was $3.16. For accounting purposes the fair value of the in-the-money warrants increased the effective interest rate over the term of the notes. In connection with this transaction, the lender under the Company's bank credit facility agreed to the Company's incurrence of additional debt and entered into an intercreditor and subordination agreement with the noteholders pursuant to which the noteholders subordinated their rights to payment to the rights of the bank under the credit facility. Principal reductions of $100,000 per year on the subordinated notes were permitted in 2005 and 2006 subject to certain conditions being met under the terms of the credit facility agreements. The Company repaid the notes in June of 2004 with proceeds of bank borrowings.

PVOG Financing

In 2004, GMX entered into an arrangement with PVOG to purchase dollar denominated production payments from the Company on wells drilled with a second rig during a portion of 2004. Under this agreement, PVOG provided to GMX $1.9 million in funding for GMX's share of costs of four wells drilled with the second rig which is repayable solely from 75% of GMX's share of production revenues from these wells without interest. As of December 31, 2004, the Present Value of GMX's interest in the wells funded in this manner was $2.8 million.

NOTE D--INCOME TAXES

Intangible development costs are expensed for income tax reporting purposes, whereas they are capitalized and amortized for financial statement purposes. Lease and well equipment and other property and equipment are depreciated for income tax reporting purposes using accelerated methods. Deferred income taxes are provided on these temporary differences to the extent that income taxes which otherwise would have been payable are reduced.

Deferred income tax assets also are recognized for operating losses that are available to offset future income taxes.

At December 31, 2004, the Company had the following carryforwards available to reduce future income taxes:

Net Operating Losses:	
Federal	$ 27,026,000
State	1,100,000
Statutory depletion	3,710,000

The net operating loss and statutory depletion carryforward amounts shown above have been utilized for financial purposes to offset existing deferred tax liabilities. The net operating loss carryforwards expire from 2018 to 2021. Statutory depletion carryforwards do not expire.

As of December 31, 2004, a deferred tax liability of $10,287,000 was primarily associated with the difference between financial carrying value of oil and gas properties and the associated tax basis. As of the same date, the Company's gross deferred tax asset of $10,516,000 was primarily the result of the net operating loss and statutory depletion carryforwards. As of December 31, 2004, the Company recognized a valuation allowance of $229,000. Management of the Company determined that based upon current taxable income and financial conditions, it is likely that the Company will not be able to utilize all of its net operating loss carryforwards prior to their expiration.

	December 31,	
	2003	2004
Deferred tax assets:		
Net operating loss carry forwards	7,622,000	9,255,000
Statutory depletion carry forwards	876,000	1,261,000
Total	8,498,000	10,516,000
Deferred tax liability:		
Property, plant and equipment	(7,896,000)	(10,287,000)
Valuation allowance	(602,000)	(229,000)
Total	(8,498,000)	(10,516,000)
Net deferred tax asset	---	---

As of December 31, 2003, the Company's deferred tax liability of $7,896,000 was primarily associated with the difference between financial carrying value of oil and gas properties and the associated tax basis. As of the same date, the Company's deferred tax asset of $8,498,000 was primarily the result of the Company's net operating loss and statutory depletion carryforwards.

Total income tax expense for the respective years differed from the amounts computed by applying the U.S. federal tax rate to earnings before income taxes as a result of the following:

	For The Year Ended December 31, 2003	For The Year Ended December 31, 2004
U.S. statutory tax rate	34%	34%
Statutory depletion	(93)	(25)
Change in valuation allowance	58	(24)
Other	1	16
Effective income tax rate	---	1

NOTE E--COMMITMENTS AND CONTINGENCIES

The Company is party to various other legal actions arising in the normal course of business. Matters that are probable of unfavorable outcome to the Company and which can be reasonably estimated are accrued. Such accruals are based on information known about the matters, the Company's estimates of the outcomes of such matters, and its experience in contesting, litigating, and settling similar matters. None of the actions are believed by management to involve future amounts that would be material to the Company's financial position or results of operations after consideration of recorded accruals.

OPERATING LEASES: The following is a schedule by year of future minimum rental payments required under operating leases that have initial or remaining non-cancelable lease terms in excess of one year as of December 31, 2004.

Year Ending December 31:

2005	$	100,357
2006		100,178
2007		23,846
2008		8,974
Total	$	233,355

Total rental expense for all operating leases is as follows for the years ended December 31:

2003	$	195,468
2004		153,613

NOTE F--SHAREHOLDERS' EQUITY

In October 2000, the board of directors and shareholders adopted the GMX Resources Inc. Stock Option Plan (the "Option Plan"). Under the Option Plan, the Company may grant both stock options intended to qualify as incentive stock options under Section 422 of the Internal Revenue Code and options which are not qualified as incentive stock options. Options may be granted under the Option Plan to key employees and nonemployee directors.

The maximum number of shares of common stock issuable under the Option Plan is 550,000, subject to appropriate adjustment in the event of a reorganization, stock split, stock dividend, reclassification or other change affecting the Company's common stock. All executive officers and other key employees who hold positions of significant responsibility are eligible to receive awards under the Option Plan. In addition, each director of the Company is eligible to receive options under the Option Plan. The exercise price of options granted under the Option Plan is not less than 100% of the fair market value of the shares on the date of grant. Options granted under the Plan become exercisable as the board may determine in connection with the grant of each option. In addition, the board may at any time accelerate the date that any option granted becomes exercisable.

The board of directors may amend or terminate the Option Plan at any time, except that no amendment will become effective without the approval of the shareholders except to the extent such approval may be required by applicable law or by the rules of any securities exchange upon which the Company shares are admitted to listed trading. The Option Plan will terminate in 2010, except with respect to awards then outstanding.

On April 15, 2003, the Company granted an option to a consultant to purchase 100,000 shares of common stock at a price of $1.00 per share. Options on 25,000 shares were vested on the date of the grant and the balance vest 25,000 on July 15, 2003, 25,000 on October 15, 2003 and 25,000 on January 1, 2004. The fair value of the stock options granted was recognized in 2003.

In January 2004, the Company raised $1 million from the sale of 11% senior subordinated notes due January 31, 2007 and five-year detachable warrants to purchase 175,000 shares of common stock for $1.50 per share. The price of the Company's common shares as of that date was $3.16. The fair market value of the warrants in the amount of $257,250 were costs of acquiring the debt and amortized over the life of the debt. These warrants were all exercised for total proceeds of $262,500 in June 2004.

In addition, in April 2004 the Company closed a private placement of 200,000 shares of common stock for $1,000,000 with a single institutional investor. Also, in June 21, 2004, the Company closed a private placement of 1,100,000 shares of common stock for $7,535,000 with several institutional investors. Proceeds of the transactions will be used for general corporate purposes.

The Company's Class A warrants allow holders to purchase common shares of the Company for $12.00 per share until February 12, 2006 and were issued in connection with the Company's initial public offering in 2001. During the 4th quarter of 2004, the Company repurchased 94,600 Class A warrants for $61,930.

NOTE G--MAJOR CUSTOMERS

Sales to individual customers constituting 10% or more of total oil and gas sales for each of the years ended December 31, 2003 and 2004 were as follows:

	2003	2004
Teppco Crude (Oil)	99%	93%
CrossTex Energy Services, Inc. (Gas)	83%	63%
Penn Virginia Oil & Gas (Gas)	---	21%
Duke Energy (Gas)	---	10%

NOTE H--CONCENTRATION OF CREDIT RISK

The Company maintains its cash in bank deposit accounts which, at times, may exceed federal insured limits. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant risk.

NOTE I--OIL AND GAS OPERATIONS (Unaudited)

Capitalized costs related to the Company's oil and gas producing activities as of December 31, 2003 and 2004 are:

	2003	2004
Unproved properties	$ 1,229,787	$ 559,407
Producing properties	31,219,309	41,893,563
	32,449,096	42,452,970
Less accumulated depreciation, depletion, and Amortization	(4,788,779)	(6,496,210)
Net capitalized costs	$27,660,317	$35,956,760

Unproved properties include leaseholds under exploration. Producing properties include mineral properties with proved reserves, development wells, and uncompleted development well costs. Support equipment and facilities include costs for pipeline facilities, field equipment, and other supporting assets involved in oil and gas producing activities. The accumulated depreciation, depletion, and amortization represent the portion of the assets which has been charged to expense.

Costs incurred in oil and gas property acquisitions, exploration, and development activities in 2003 and 2004 are as follows:

	2003	2004
Property acquisition costs – proved	$ 57,575	$ ---
Property acquisition costs – unproved	5,212	851,617
Development costs	175,840	9,152,257
	$ 238,627	$ 10,003,874

Developments costs above include non-cash Asset Retirement Costs of $1,436,184.

Development costs include the cost of drilling and equipping development wells and constructing related production facilities for extracting, treating, gathering, and storing oil and gas from proved reserves.

The Company's results of operations in 2003 and 2004 include revenues and expenses associated directly with oil and gas producing activities.

	2003	2004
Oil and gas sales	$ 5,367,370	$ 7,689,882
Production costs	<1,211,582>	<1,779,830>
Depreciation, depletion and amortization	<1,214,779>	<1,707,431>
Income tax expense	<733,670>	<1,047,075>
Results of operations for oil and gas producing activities	$ 2,207,339	$ 3,155,546

NOTE J--SUPPLEMENTAL INFORMATION ON OIL AND GAS OPERATIONS (UNAUDITED)

The oil and gas reserve quantity information presented below is unaudited and is based upon reports prepared by independent petroleum engineers. The information is presented in accordance with regulations prescribed by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise. The Company's reserve estimates were estimated by performance methods, volumetric methods, and comparisons with analogous wells, where applicable. The reserves estimated by the performance method utilized extrapolations of historical production data. Reserves were estimated by the volumetric or analogous methods in cases where the historical production data was insufficient to establish a definitive trend. Accordingly, these estimates are expected to change, and such changes could be material and occur in the near term as future information becomes available.

Proved oil and gas reserves represent 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 existing economic and operating conditions. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. As of December 31, 2003 and 2004, all of the Company's oil and gas reserves were located in the United States.

	OIL (MBBLS)	GAS (MMCF)
December 31, 2003		
Proved reserves, beginning of period	1,664	56,682
Extensions, discoveries, and other additions	---	---
Production	(35)	(917)
Sale of reserves in-place	(251)	(11,414)
Revisions of previous estimates	(55)	678
Proved reserves, end of period	1,323	45,029
Proved developed reserves:		
Beginning of period	604	16,501
End of period	568	18,277
December 31, 2004		
Proved reserves, beginning of period	1,323	45,029
Extensions, discoveries, and other additions	51	14,644
Production	(30)	(1,049)
Sale of reserves in-place	---	---
Revisions of previous estimates	(107)	(1,736)
Proved reserves, end of period	1,237	56,888
Proved developed reserves:		
Beginning of period	568	18,277
End of period	584	18,980

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to the estimated quantities of oil and gas to be produced. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. Estimated future income taxes are computed using current statutory income tax rates including consideration of the current tax bases of the properties and related carryforwards giving effect to permanent differences. 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 revenue to be derived from those reserves nor their present worth. 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.

The following summary sets forth the Company's future net cash flows relating to proved oil and gas reserves based on the standardized measure prescribed in Statement of Financial Accounting Standards No. 69.

	December 31, 2003 (In thousands)	December 31, 2004 (In thousands)
Future cash inflows	$ 300,514	$ 375,427
Future production costs	(77,608)	(94,338)
Future development costs	(44,557)	(66,811)
Future income tax provisions	(58,158)	(48,926)
Net future cash inflows	120,191	165,352
Less effect of a 10% discount factor	(72,216)	(101,120)
Standardized measure of discounted future net cash flows	$ 47,975	$ 64,231

Oil and condensate prices were based on an equivalent base price of $43.45 per barrel for benchmark posted West Texas Intermediate Crude Oil at closing on December 31, 2004. Adjustments to the base price were made to each lease to adjust the base price for crude oil quality, contractual agreements, and regional price variations. The average oil price used in the reserve estimates was $42.02 per barrel. Natural gas prices were based on an equivalent base price of $6.149 per million British thermal unit (mmbtu) for the composite Henry Hub Spot Market benchmark price at closing on December 31, 2004. Adjustments to the base price were made to each lease to adjust the base price for quality, contractual agreements, and regional price variations. The average natural gas price used in the reserve estimates was $5.69 per mmbtu. Future income tax expenses are computed by applying the appropriate statutory rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved giving effect to permanent differences, tax credits, and allowances relating to proved oil and gas reserves.

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	December 31, 2003 (In thousands)	December 31, 2004 (In thousands)
Standardized measure, beginning of year	$ 54,312	$ 47,975
Sales of oil and gas, net of production costs	(4,156)	(5,910)
Net changes in prices and production costs	11,782	4,409
Extensions and discoveries, net of future development costs	---	18,949
Development costs that reduced future development costs	---	6,863
Revisions of quantity estimates	646	(4,035)
Sales of reserves in place	(16,434)	---
Accretion of discount	8,061	1,149
Other	(9,322)	<9,379>
Net changes in income taxes	3,086	4,210
Standardized measure, end of year	$ 47,975	$ 64,231