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

Form ~~10-KSB/A~~

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[X] ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2003

[ ] 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. [X]

The issuer's revenue for the year ended December 31, 2003 was $5,388,794.

The aggregate market value of the voting and non-voting common equity (excluding warrants) held by non-affiliates on April 13, 2004 was $17.8 million. This amount was computed using closing price of the issuer's common stock on April 13, 2004 on the NASDAQ National Market.

As of April 13, 2004, the issuer had outstanding a total of 6,775,000 shares of its $0.001 par value Common Stock.

Documents incorporated by reference - None

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

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PART I

Item 1. BUSINESS

General

GMX Resources Inc. (referred to herein as "GMX" or the "Company") is an independent oil and gas company headquartered in Oklahoma City, Oklahoma. 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

On February 12, 2001, we completed an initial public offering of 1,250,000 units at $8.00 per unit underwritten by Paulson Investment Company, Inc. and I-Bankers Securities Incorporated. 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 units traded as units until March 15, 2001 when the common stock, Class A warrants and Class B warrants became separately tradeable on the NASDAQ SmallCap Market. The net proceeds of the offering amounting to approximately $8.5 million were used primarily for development drilling in 2001.

On June 22, 2001, our common stock became eligible for trading on the NASDAQ National Market. 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. This firm commitment offering was also underwritten by Paulson Investment Company, Inc., and I-Bankers Securities Incorporated. 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.

Drilling Contract

On May 29, 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. The day rate was payable regardless of whether we were actually using the rigs. Our payment obligations were secured by standby letters of credit in the aggregate amount of $1,000,000, $500,000 per rig, issued by our lender under our credit facility in favor of Nabors.

On December 13, 2001, we terminated the contracts 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. On December 20, 2002, we received a jury verdict in our favor in our lawsuit against Nabors in the United States District Court for the Western District of Oklahoma after a five day trial. As a result of the jury verdict, the Company had no liability to Nabors on its claim for approximately $10 million in contract termination damages. In March 2003, Nabors filed a notice of appeal of the jury verdict. In May 2003, GMX and Nabors settled the lawsuit. Nabors dismissed its appeal and both parties executed mutual releases of all claims.

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 July 2002, we engaged Petroleum Place Advisors ("Petroleum Place") to assist us as a financial advisor in connection with possible property sales and other alternatives. Effective as of September 30, 2002, we completed the sale of all of our oil and gas properties in Kansas which had proved reserves of 9,571 Mmcfe. Net proceeds of the sales were $3.6 million, of which $3.3 million was applied to our bank debt. We also solicited bids through Petroleum Place for either a purchase of our east Texas properties or a joint venture to develop these properties. This process concluded in December 2002. After our success in the trial court in the Nabors litigation, we elected to evaluate other strategic alternatives rather than accept proposals made at that time.

Since the settlement of the Nabors litigation in May of 2003, we have continued to actively seek additional sources of financing from outside sources including potential industry partners or private sources of debt and equity financing. As a result of the maturity of our bank credit facility in May of 2003, we were in default under this facility until August 31, 2003 when we negotiated an amended agreement and extended our then existing credit line of $7.2 million to mature on March 1, 2004. Even though the Company was able to negotiate extensions in its bank credit facility, during much of 2002 and 2003, the Company had significant accounts payable over 90 days which it was able to gradually reduce over this time frame.

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.

On December 29, 2003, we executed a definitive participation agreement with Penn Virginia Oil & Gas Corporation ("PVOG"), a wholly-owned subsidiary of Penn Virginia Corporation , a publicly-held company traded on the New York Stock Exchange under the symbol PVA, for the joint development of our Cotton Valley, Travis Peak and Pettit prospects located in East Texas. This agreement designates agreed geographic areas which surround and encompass distinct portions of our acreage positions in East Texas defined as "Phases." PVOG began drilling on February 11, 2004 in "Phase I," which includes approximately 4,289 net acres comprising a portion of our proved undeveloped acreage. GMX will have a 20% carried interest in the first five wells drilled in Phase I and will have a right to participate for 30% of additional Phase I wells. Phase II, which includes approximately 5,200 net acres of our acreage, may commence after completion of Phase I, five carried wells and no earlier than January 1, 2005 and no later than July 1, 2005. In Phase II, GMX will have a 20% carried interest in the first four wells and will have a right to participate for 50% of additional drilling in Phase II. GMX received approximately $950,000 in acreage and drilling location cost reimbursement which was applied to reduce current liabilities. For additional information concerning the PVOG agreement, see "Item 2 - Properties."

On January 16, 2004, we completed a private placement of $1 million of 11% senior subordinated notes maturing in 2007 with annual principal installments prior to maturity of $100,000 and five year warrants to purchase 175,000 shares of common stock for $1.50 per share. The proceeds of this placement are being used for completion of wells with proved developed non-producing reserves, other production enhancement, further reduction in current liabilities, placement fees and transaction costs associated with the transaction.

In addition on April 5, 2004, the Company closed a private placement of 200,000 shares of common stock for $1,000,000 with an investor. Proceeds of the transaction will be used for general corporate purposes. We are also actively pursuing other sources of external financing through private equity offerings and expect that additional placements may occur.

Effective March 1, 2004, we reached an agreement with our bank lender to extend our existing credit line of $6,260,000 to mature on September 1, 2004. The Company will continue to make monthly payments of $90,000 in principal payments plus interest at New York prime plus 1% until the maturity date. On April 14, 2004, our bank offered to extend the maturity of the line to September 1, 2005, if we use the $1 million common stock sale proceeds to repay the 11% subordinated notes. We are considering the proposal, but in the meantime, we are evaluating several other proposals from other bank lenders to maximize our flexibility for refinancing the credit facility and increasing our borrowing base. As of April 14, 2004, we have received three term sheets from these prospective lenders. See "Management's Discussion and Analysis on Plan of Operation."

As a result of the PVOG and private placement transactions, the Company's liquidity has been substantially improved and as of April 6, 2004, the Company has sufficient working capital to meet its accounts payable obligations on a timely basis. The Company's cash flow in 2004 is expected to be sufficient to meet its current obligations as they become due as well as to finance some limited recompletion and production enhancement activities.

Since year end 2003 through April 6, 2004, PVOG has drilled and completed one well under our participation agreement in which we have a 20% carried interest and has commenced the drilling of a second carried interest well. We have conducted recompletion or production enhancement operations on three wells in which we have 100% working interest. These wells have been recompleted in the Pettit, Travis Peak and Cotton Valley formations. They were producing approximately 1,500 mcfpd as of April 6, 2004, but this production rate is expected to decline in the normal course of production.

Business Strategy

If we are able to obtain financing, our strategy will be 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 29 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 which manufactured and sold road building equipment.

Substantial Drilling and Exploitation Opportunities. We have a substantial inventory of drilling and recompletion projects with an estimated 31 Bcfe of proved undeveloped reserves as of December 31, 2003. These projects include 27 recompletion projects and 52 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, 2003 reserve report, the pre-tax present value of the proved reserves is $71 million with anticipated future development costs of $44.5 million.

Significant Inventory of Unproved Prospects. We have approximately 200 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 can be held and drilled in order of priority without concern about lease expiration.

Emphasis on Gas Reserves. Production for 2003 was 82% gas and 18% oil. Proved reserves as of December 31, 2003 are 85% gas and 15% 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.

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. During the past several years, regional surpluses and shortages of natural gas have occurred, resulting in wide fluctuations in prices received.

Substantially all of our gas from our East Texas 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.

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 generally an established or "posted" price that is offered to all producers. During the last several years prices paid for crude oil have fluctuated substantially. Future oil prices are difficult to predict due to the impact of worldwide economic trends, coupled with supply and demand variables, and such non-economic factors as the impact of political considerations on Organization of the Petroleum Exporting Countries ("OPEC") pricing policies and the possibility of supply interruptions.

Our largest purchasers include TEPPCO Crude and Crosstex Pipeline Company, which accounts for 99% and 83% of oil and natural gas sales currently. We do not believe that the loss of any of our purchasers would have a material adverse affect on our operations. None of our gas or oil sales contracts have a term of more than one year.

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 currently 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. The interstate transportation and sale for resale of natural gas is regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938. The sale and transportation of natural gas also is subject to regulation by various state agencies. The Natural Gas Wellhead Decontrol Act of 1989 eliminated all gas price regulation effective January 1, 1993. In addition, FERC recently has proposed several rules and orders concerning transportation and marketing of natural gas. We cannot predict the impact of these rules and other regulatory developments on the Company or our operations.

In 1992, FERC finalized Order 636, and also has promulgated regulations pertaining to the restructuring of the interstate transportation of natural gas. Pipelines serving this function have since been required to "unbundle" the various components of their service offerings, which include gathering, transportation, storage, and balancing services. In their current capacity, pipeline companies must provide their customers with only the specific service desired, on a non-discriminatory basis. Although we are not an interstate pipeline, we believe the changes brought about by Order 636 have increased competition in the marketplace, resulting in greater market volatility.

Various rules, regulations and orders, as well as statutory provisions may affect the price of natural gas production and the transportation and marketing of natural gas.

Gas Gathering

We have acquired, constructed and own, through a wholly-owned subsidiary, Endeavor, gas gathering lines and compression equipment for gathering and delivering of natural gas from our east Texas properties. As of December 31, 2003, this gathering system consisted of approximately 34 miles of gathering lines that collect gas from approximately 40 wells, which accounted for approximately 95% of our gas production from this area in both 2003 and 2002. 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."

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 the regions in which we own properties has resulted in increased demand for drilling rigs and other oilfield equipment and services. We may 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, 2003, we leased approximately 6,749 square feet in Oklahoma City, Oklahoma for our corporate headquarters. The annual rental cost is approximately $82,000.

Employees

As of December 31, 2003, we had eight full-time employees of which three are management and the balance are clerical or technical employees. This is down from 11 full-time employees at December 31, 2002 and 18 at December 31, 2001. We also use five 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. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not escalations based upon future conditions.

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

As of December 31, 2003, we owned properties in the following productive basins in the United States:

- The Sabine Uplift in East Texas and Louisiana;
- The Tatum Basin in Southeast New Mexico.

The following table sets forth certain information regarding our activities in each of these areas as of December 31, 2003.

	East Texas and Louisiana	Southeast New Mexico	Total
Property Statistics:			
Proved reserves (MMcfe)	51,681	1,286	52,967
Percent of total proved reserves	98%	2%	100%
Gross producing wells	48	7	55
Net producing wells	36.1	5.6	41.7
Gross acreage	18,847	2,077	20,924
Net acreage	10,120	1,821	11,941
Proved developed nonproducing reserves (MMcfe)	21,156	530	21,686
Proved undeveloped reserves (MMcfe)	30,527	755	31,282
Estimated total future development costs ($000s)	$ 44,058	$ 500	$ 44,558
Estimated 2004 development costs ($000s)	6,183	500	6,683
Proved undeveloped locations	51	1	52
Year ended December 31, 2003 results:			
Production (net MMcfe)	1,051	73	1,124
Average net daily production (Mcfe)	2,880	194	3,074

Additional information related to our oil and gas activities is included in Notes J and K 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 18,167 gross (9,764 net) acres with rights covering the Travis Peak, Pettit, Glen Rose and Cotton Valley formations. Our East Texas properties have 51.2 Bcfe of proved reserves or 97% of our total proved reserves at December 31, 2003, of which 30.5 Bcfe is classified as proved undeveloped.

We have interests in 42 gross (33.7 net) producing wells in East Texas, of which we operate 37. Average daily production net to our interest for 2003 was 2,434 Mcf of gas and 68 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 41.4 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.

In 2001, GMX successfully drilled and completed ten wells on its East Texas property. Most of these were dual completions, each well having two or more separate producing reservoirs in either the Pettit, Travis Peak or Cotton Valley geological formations from 6,000 to 10,000 feet deep. The dual completions have the same effect as drilling 20 separate single zone wells. We did not drill any wells in 2002 or 2003 due to a lack of financial resources. Annual production volumes of oil and natural gas net to the Company's interest for 2003 was 1,005 Mmcfe compared with production in 2002 of 1,858 Mmcfe, a year-over-year decrease of 46%.

For 2004, GMX initially plans to participate in ten wells in East Texas during 2004 and recomplete seven wells, subject to availability of capital resources. The pace of future development of this property will depend on the pace of PVOG's activity under our joint participation agreement described below, availability of capital, future drilling results, the general economic conditions of the energy industry and, on the price the Company receives for the natural gas and crude oil produced. There is a potential for up to 400 locations of Cotton Valley wells in our East Texas acreage assuming an ultimate well density of two wells in each 80 acre tract.

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. This agreement designates agreed geographic areas which surround and encompass distinct portions of our acreage positions in East Texas defined as "Phases." PVOG began drilling on February 11, 2004 in "Phase I," which includes approximately 5,082 net acres comprising a portion of our proved undeveloped acreage. GMX will have a 20% carried interest in the first five (5) wells drilled in Phase I and will have a right to participate for 30% of additional Phase I wells. Phase II, which includes approximately 5,670 net acres of our acreage, may commence after completion of Phase I, five (5) carried wells and no earlier than January 1, 2005 and no later than July 1, 2005. In Phase II, GMX will have a 20% carried interest in the first four (4) wells and will have a right to participate for 50% of additional drilling in Phase II. GMX received approximately $950,000 in acreage and drilling location cost reimbursement which was applied to reduce current liabilities.

The PVOG agreement also designates areas of mutual interest ("AMIs") in which GMX and Penn Virginia agree that they will have rights to jointly acquire acreage. The Phase I AMI consists of 20,500acres 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 22,400acres 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.

PVOG has publicly annouced plans to drill eight wells in 2004 on the Phase I acreage.

At December 31, 2003, Sproule Associates, Inc., our independent reserve engineering firm, assigned a total of 10.6 Bcfe of proved reserves to the completed East Texas wells, 10.1 Bcfe to our proved developed non-producing wells, and 30.5 Bcfe of proved undeveloped reserves to our 51 proved undeveloped locations in East Texas.

Northwestern Louisiana

The Louisiana properties are located in Clairborne, Caddo, Catahoula and Webster parishes with production from the Cotton Valley, Hosston and Rodessa formations. We have six gross (2.4 net) producing wells, three of which we operate. Production is predominately oil. Louisiana proved reserves are .5 Bcfe and represent approximately 1% of proved reserves as of December 31, 2003. Average daily production net to our interest for 2003 was 3 Bbls of oil and 22 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 2,077 gross (1,821 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 2% of our total proved reserves as of December 31, 2003. Average daily production net to our interests for 2003 from our 7 gross (5.6 net) producing wells in this area was 53 Mcf of gas and 24 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 and we are considering 3D seismic evaluations of these formations.

Reserves

As of December 31, 2003, Sproule Associates Inc. estimates our proved reserves are 53 Bcfe. An estimated 22 Bcfe is expected to be produced from existing wells and another 31 Bcfe or 59% of the proved reserves, is classified as proved undeveloped. All of our proved undeveloped reserves are on locations which are adjacent to wells productive in the same formations. As of December 31, 2003, we had interests in 59 producing wells, 47 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,		
	2001	**2002**	**2003**
Proved Developed:			
Gas (MMcf)	21,932	16,501	18,277
Oil (MBbls)	1,018	604	568
Total (MMcfe)	28,040	20,125	21,685
Proved Undeveloped:			
Gas (MMcf)	46,679	40,181	26,752
Oil (MBbls)	2,844	1,060	755
Total (MMcfe)	63,740	46,541	31,282
Total Proved:			
Gas (MMcf)	68,611	56,683	45,029
Oil (MBbls)	3,862	1,663	1,323
Total (MMcfe)	91,781	66,663	52,967
Estimated Future Net Revenues (1)($000s)	$155,678	$186,336	$178,348
Present Value(1)($000s)	$ 70,952	$ 80,614	$ 71,192

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(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. The standardized measure of discounted future net cash flows as of 2001, 2002 and 2003 was $48,524,000, $54,312,000, and $47,975,000respectively.

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 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 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 $44.5 million as of December 31, 2003, of which $7.2 million is scheduled in the reserve report to be expended in 2004. We do not currently have the resources to fund these development costs and, accordingly, there is substantial uncertainty about our ability to develop these proved undeveloped reserves in the time frame estimated in the reserve report. If we enter into additional joint ventures or other arrangements to fund some or all of the development costs, our interests in the reserves would likely be reduced, as they were in connection with the PVOG participation agreement. Accordingly, there is no assurance we will be able to realize the value of our estimated proved undeveloped reserves.

Estimates of the quantity and value of our proved undeveloped reserves is also 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. Our year end reserve estimates assumes that PVOG will earn its rights in the Phase II acreage for a limited number of Phase II wells. Our reserve estimates would be increased if PVOG does not earn rights in Phase II and would be decreased if PVOG fully participates in the Phase II potential drilling.

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, 2003 were $32.52 per barrel for oil and $6.189 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 $500,000 and $1,000,000 , respectively, as of December 31, 2003.

Sproule Associates, Inc., our independent reserve engineers, prepared the estimates of proved reserves as of December 31, 2003, 2002 and 2001.

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 and Acquisition and Drilling Results

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,		
	2001	2002	2003
Property acquisition costs:			
Proved	$ 2,382,548	$ 120,157	$ 57,565
Unproved	2,488,614	84,672	5,212
Development costs	19,270,480	2,812,876	173,840
Total	$24,141,642	$3,017,705	$236,617

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,					
	2001		2002		2003	
Development wells:	Gross	Net	Gross	Net	Gross	Net
Gas	10	10	---	---	---	---
Oil	1	.5	---	---	---	---
Dry	---	---	---	---	---	---
Total	11	10.5	---	---	---	---

The following table shows our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2003. 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	13,045	12,450	6,818	5,163
Southeast New Mexico	1,760	1,504	317	317
Total	14,805	13,954	7,135	5,480

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, 2003 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.

	Productive Wells	
Type of Well	Gross	Net
Gas	34	27.9
Oil	21	13.8
Total	55	41.7

Item 3. LEGAL PROCEEDINGS

None.

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

The annual meeting of shareholders was held on December 15, 2003, and the four incumbent directors were elected for the ensuing year with the following votes.

Name	Votes For	Withheld Authority
Ken L. Kenworthy, Jr.	6,365,873	48,309
Ken L. Kenworthy, Sr.	6,365,873	48,309
T. J. Boismier	6,365,873	48,309
Steven Craig	6,365,873	48,309

PART II

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

Common Stock 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
January 1, 2002 to March 31, 2002				
Common Stock	$	4.65	$	2.40
Class A warrants		1.85		0.60
April 1, 2002 to June 30, 2002				
Common Stock	$	3.80	$	2.06
Class A warrants		0.76		0.32
July 1, 2002 to September 30, 2002				
Common Stock	$	2.60	$	1.50
Class A warrants		0.32		0.04
October 1, 2002 to December 31, 2002				
Common Stock	$	2.45	$	0.89
Class A warrants		0.22		0.01
January 1, 2003 to March 31, 2003				
Common Stock	$	1.96	$	1.06
Class A Warrants		0.50		0.05
April 1, 2003 to June 30, 2003				
Common Stock	$	2.14	$	0.63
Class A Warrants		0.49		0.04
July 1, 2003 to September 30, 2003				
Common Stock	$	2.23	$	1.33
Class A Warrants		0.19		0.09
October 1, 2003 to December 31, 2003				
Common Stock	$	4.50	$	1.30
Class A Warrants		0.72		0.09

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

As of March 15, 2004, there were 33 record owners of our Common Stock and approximately 1,660 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 previously had outstanding Class B warrants but these expired by their own terms on February 12, 2003 and have not been extended.

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.

Recent Sales of Unregistered Securities

None during the fourth quarter of 2004.

Purchases of Equity Securities by the Small Business Issuer

None

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,		
	2001	2002	2003
Statement of Operations Data:			
Oil and gas sales	$ 5,898,003	$ 5,970,792	$ 5,367,370
Interest and other income	554,296	17,550	21,424
Total revenues	6,452,299	5,988,342	5,388,794
Lease operations	1,604,559	1,324,481	827,513
Production and severance taxes	338,637	382,826	384,069
General and administrative	1,855,736	2,577,388	1,578,865
Depreciation, depletion and amortization	1,026,498	1,901,976	1,549,678
Accretion expense on asset retirement obligations	---	---	22,521
Interest	359,118	510,472	439,313
Total expenses	$ 5,184,548	$ 6,697,142	$ 4,801,959
Income (loss) before income taxes	1,267,751	(708,800)	586,835
Income tax expense (benefit)	211,000	(263,000)	---
Net income before cumulative effect of a change in accounting principle	$ 1,056,751	$ (445,800)	$ 586,835
Cumulative effect of a change in accounting principle	$ ---	$ ---	$ (51,834)
Net income (loss) applicable to common shares	$ 1,056,751	$ (445,800)	$ 535,001
Net income (loss) per share – before cumulative effect	$ .21	$ (.07)	$ .09
Cumulative effect	$ ---	$ ---	$ .01
Net income (loss) per share – basic and diluted	$ .20	$ (.07)	$ .08
Weighted average common shares - basic	5,148,493	6,550,000	6,560,000
Weighted average common shares - diluted	5,179,693	6,550,000	6,560,000
Statement of Cash Flows Data:			
Net cash provided by (used in) operating activities	$ 8,016,600	$ (2,547,639)	$ 1,014,290
Net cash provided by (used in) investing activities	(26,700,785)	1,267,831	464,315
Net cash provided by (used in) financing activities	18,657,867	1,820,000	(1,385,000)
Balance Sheet Data (at end of period):			
Oil and gas properties, net	$ 32,148,615	$ 29,359,309	$ 27,660,317
Total assets	36,719,674	33,319,432	31,501,206
Long-term debt, including current portion	6,280,000	8,100,000	6,690,000
Shareholders' equity	22,474,563	21,607,463	22,618,565

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,		
	2001	2002	2003
Production:			
Oil production (MBbls)	81	70	35
Natural gas production (MMcf)	1,294	1,639	917
Equivalent production (MMcfe)	1,778	2,059	1,124
Average Sales Price:			
Oil price (per Bbl)	$ 24.86 (1)	$ 23.48 (1)	$ 30.41
Natural gas price (per Mcf)	3.01 (1)	3.03 (1)	4.73 (1)
Average sales price (per Mcfe)	$ 3.33	$ 3.22	$ 4.79
Operating and Overhead Costs (per Mcfe):			
Lease operating expenses	$ .90	$ .64	$ .74
Production and severance taxes	.19	.19	.34
General and administrative	1.05	1.25	1.40
Total	$ 2.14	$ 2.08	$ 2.48
Operating Margin (per Mcfe)	$ 1.19	$ 1.14	$ 2.31
Other (per Mcfe):			
Depreciation, depletion and amortization - oil and gas production	$ .58	$ .92	$ 1.08
Estimated Net Proved Reserves (as of the respective period-end):			
Natural gas (Bcf)	68.6	56.7	45.0
Oil (MMbls)	3.9	1.7	1.3
Total (Bcfe)	91.8	66.7	53.0
Estimated Future Net Revenues ($MM) (2)(3)	$ 155.7	$ 486.3	$ 178.3
Present Value ($MM) (2)(3)	$ 71.0	$ 80.6	$ 71.2
Standardized measure of discounted future net cash flows ($mm) (4)	$ 48.5	$ 54.3	$ 48.0

(1) Net of results of (i) hedging activities which increased the average oil price in 2001 by $.95 per Bbl and (ii) gas hedging activities which reduced the average gas price in 2001 by $.14 per Mcf and $.40 per Mcf in 2002, 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.

Critical Accounting Policies

The preparation of the consolidated financial statements requires management of the Company 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 the Company's 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

GMX follows the full cost method of accounting for its oil and natural gas properties. 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 GMX's capitalized costs are in excess of the calculated ceiling, the excess must be written off as an expense.

GMX's discounted present value of estimated future net revenues from its 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 GMX's 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 GMX's 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 GMX's long-term price forecast that is a barometer for true fair value. 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.

The Company's asset retirement obligations ("ARO") consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its 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, 2003, the Company's balance sheet included a liability for ARO of $304,000.

Results of Operations for the Year Ended December 31, 2003 Compared to 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. 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 the year of 2002. During 2003, the Company 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 compared to 1,639 MMcf for the year of 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 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. We expect that 2004 general and administrative expense will increase compared to 2003 as a result of increases in our overall levl of activity.

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.

Results of Operations for the Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Oil and Gas Sales. Oil and gas sales in the year ended December 31, 2002 increased 1% to $5,970,792 compared to the year ended December 31, 2001, due to increased production. The average price per barrel of oil and mcf of gas received in 2002 was $23.48 and $3.03, respectively, compared to $24.86 and $3.01 in the year of 2001. During 2002, the company hedged 900,000 Mcf of gas through price swap agreements with a fixed price of $2.664 per Mcf. The price swap agreements reduced sales by $652,100. Oil production for 2002 decreased because of the September 2002 sale of Kansas properties. Gas production increased to 1,639 MMcf compared to 1,294 MMcf for the year of 2001, an increase of 27%. Increased production in 2002 resulted from new production from wells drilled in 2001 and the reworking of certain wells.

Lease Operations. Lease operations expense decreased $280,078 in 2002 to $1,324,481 a 17% decrease compared to 2001. Decreased expenses resulted from the sale of Kansas properties. Lease operations expense on an equivalent unit of production basis was $0.64 per Mcfe in 2002 compared to $0.90 per Mcfe for 2001, primarily from the decreased oil production and the full year effect of the higher volume gas wells drilled in 2001.

Production and Severance Taxes. Production and severance taxes increased 13% to $382,826 in 2002 compared to $338,637 in 2001. 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 increased oil and gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $875,478 to $1,901,976 in 2002, up 85% from 2001. This increase is due primarily to an increase in the depletion rate for 2002 from the drilling of new wells in 2001 when drilling costs were high. The oil and gas depreciation, depletion and amortization rate per equivalent unit of production was $0.92 per Mcfe in 2002 compared to $0.58 per Mcfe in 2001.

Interest. Interest expense for the year 2002 was $510,472 compared to $359,118 for the year of 2001. This increase is primarily attributable to higher average long term debt balances outstanding during 2002.

General And Administrative Expense. General and administrative expense for 2002 was $2,577,388 compared to $1,855,736 for 2001, an increase of 39%. This increase of $721,652 was the result of an increase in salaries and payroll expenses of $259,000 and an increase in legal and professional fees primarily in connection with the Nabors Drilling lawsuit of $363,000 and other general and administrative expenses of $99,000. The salary increase was a result of an increase in administrative personnel. General and administrative expense per equivalent unit of production was $1.25 per Mcfe for the 2002 period compared to $1.05 per Mcfe for the comparable period in 2001. In late 2002, we reduced personnel and accordingly expect salaries and payroll expense to decline in 2003. We expect to continue to incur legal fees for the Nabors drilling appeal but these costs should be significantly less than pre-trial and trial expenses.

Income Taxes. Income tax benefit for year of 2002 was $263,000 as compared to an expense of $211,000 in 2001. This decrease resulted from the Company's net loss incurred in 2002.

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.

In 2001, we raised $19.8 million in public offerings of common stock and warrants. By December 31, 2001, these proceeds had been fully used, primarily for development drilling. As a result of uncertainties relating to pending litigation with a former drilling contractor, we were unable to obtain additional advances to drill or for other purposes and were in default under the terms of our credit facility from time to time from year end 2001 until August 2003. Due to these liquidity considerations there existed uncertainties about our ability to continue operating as a going concern at year end 2001 and 2002. We did not engage in any development activity in 2002 or 2003 due to a lack of financial resources.

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.

Cash Flow—Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

In 2002 we had a deficit cash flow from operating activities of $2,547,639 as a result of reductions in net income and from payments of 2001 accounts payable during 2002. Our cash flow from operating activities in 2001 was $8,016,600 primarily due to 2001 net income and increases in accounts payable of $6,301,732. We received a net $1,267,831 in cash from investing activities in 2002 compared to net cash expenditures of $26,700,785 in 2001. 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 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 April 6, 2004 to $6,170,000.

The credit facility has been amended on several occasions to waive non-payment default or to extend the maturity. The credit facility matured in May 2003 and we remained in default under the facility until August 2003 when the credit facility was amended to extend the maturity date of the promissory note from May 1, 2003 to new maturity date of March 1, 2004. On March 15, 2004, the bank approved an extension of the existing credit facility with the following amended terms: New maturity date of September 1, 2004, Borrowing Base of $6,310,000, monthly commitment reduction of $90,000 and all other terms in the existing credit agreement to remain unchanged. See "Liquidity and Financing Considerations" for additional information about a possible extension of maturity to September 1, 2005.

As of December 31, 2003, we had $6,690,000 outstanding under the facility. As of March 1, 2004, we had $6,260,000 outstanding.

Borrowings under the credit facility bear interest at the prime rate plus 1%. 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 monthly debt service coverage ratio of at least 1.0 to 1. 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 monthly principal reduction requirements plus interest.
- 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 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.

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 will increase the effective interest rate over the term of the notes. In connection with this transaction, the lender under our bank credit facility agreed to our 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 are permitted in 2005 and 2006 subject to certain conditions being met under the terms of the credit facility agreements.

The Company is obligated to register the warrants and underlying shares of common stock under the Securities Act of 1933 on or before June 30, 2004 in order to permit the holders to sell the warrants and underlying shares without restrictions. If the Company fails to effect or maintain such registration, it is obligated to issue additional warrants at the rate of 10,000 warrants per month such failure exists.

Common Stock Private Placement

In addition, on April 5, 2004, the Company closed a private placement of 200,000 shares of common stock for $1,000,000 with an investor. Proceeds of the transaction will be used for general corporate purposes. We are also actively pursuing other sources of external financing through private equity offerings and expect that additional placements may occur.

Working Capital

At December 31, 2003, we had a working capital deficit of $994,052. Excluding our bank debt, our working capital as of December 31, 2003 would have been $101,948. Total debt outstanding at December 31, 2003 was $6.69 million, representing 23% of our total capitalization. See liquidity below for 2004 issuances of subordinated debt and equity. As discussed above, subsequent to December 31, 2003, we raised $1 million in subordinated debt and raised $1 million from a sale of common stock.

Commitments and Capital Expenditures

The following table reflects the Company's contractual obligations as of December 31, 2003.

	Payments Due by Period (In Thousands)				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$6,690,000	$1,060,000	5,630,000	---	---
Operating leases	382,311	162,129	$220,182	---	---
Total	$7,072,311	$1,222,129	$5,880,182	---	---

Other than obligations under our credit facility and the subordinated notes, our commitments for capital expenditures relate to development of oil and gas properties. We have not entered 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, the January 2004 private placement of notes and warrants and our April 2004 private placement of common stock, our liquidity has substantially improved. Under our participation agreement with PVOG, we have a carried interest in the first five wells in Phase I and an option, but not an obligation to participate in any remaining Phase I wells for a 30% interest. As a result, we have reduced our costs and ownership relating to development of these wells. On April 14, 2004, our bank lender made a commitment to extend the maturity of our current credit facility to September 1, 2005, if we use the $1 million common stock placement proceeds to prepay our 11% subordinated notes on or before May 14, 2004. We may accept this proposal, but in the meantime are also actively evaluating several proposals from other lenders to refinance our existing bank debt to maximize our flexibility. In addition to refinancing our bank debt, we are continuing to pursue alternatives to find other sources of capital including additional development arrangements and private sources of equity or other debt financing. There can be no assurance that we would be able to enter into any of these financial arrangements. Until such sources become available, we have only limited resources for property development and drilling, but we expect to have sufficient cash flow, assuming a favorable oil and gas price environment, to meet current obligations.

Price Risk Management

We have entered into, and expect to periodically enter into, financial price risk management activities with respect to a portion of projected oil and gas production through financial price swaps whereby we receive 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, but we do not expect to manage at any time more than 75% of our total production. The gains and losses realized as a result of these activities are substantially offset in the cash market when the commodity is delivered. During 2002, we entered into price swap agreements for 50,000 and 40,000 MMBtu of natural gas per month at a fixed price of $2.66 and $2.67 per MMBtu, respectively. These arrangements managed approximately 52% of our estimated monthly gas production based on our December 31, 2001 reserve report. This hedge reduced our average realized gas price in 2002 from $3.43 to $3.03 per Mcf. This same hedge affected January and February of 2003, by reducing our average realized gas price for 2003 from $5.69 to $5.21 per Mcf.

Impact of Recently Issued Accounting Standards Not Yet Adopted

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 for this cumulative effect of change in accounting principle of $51,834.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, Consolidation of Variable Interest Entities, which was issued in January 2003. The Company will be required to apply FIN 46R to variable interests in VIEs created after December 31, 2003. For variable interests in VIEs created before January 1, 2004, the Interpretation will be applied beginning on January 1, 2005. For any VIEs that must be consolidated under FIN 46R that were created before January 1, 2004, the assets, liabilities and noncontrolling interests of the VIE initially would be measured at their carrying amounts with any difference between the net amount added to the balance sheet and any previously recognized interest being recognized as the cumulative effect of an accounting change. If determining the carrying amounts is not practicable, fair value at the date FIN 46R first applies may be used to measure the assets, liabilities and noncontrolling interest of the VIE. The Company anticipates that this standard will not have an impact on the Company's financial statements because it does not own any interests in variable interest entities.

SFAS Statement of 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, ("SFAS 150") was issued in May, 2003. SFAS 150 establishes standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. SFAS 150 also includes required disclosures for financial instruments within its scope. SFAS 150 was effective for instruments entered into or modified after May 31, 2003 and otherwise will be effective as of January 1, 2004, except for mandatorily redeemable financial instruments. For certain mandatorily financial instruments, FSAS 150 will be effective on January 1, 2005. The effective date has been deferred indefinitely for certain other types of mandatorily redeemable financial instruments. The Company currently does not have any financial instruments that are within the scope of SFAS 150.

During 2003, a reporting issue arose regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. The EITF has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how GMX classifies these assets. Historically, the Company has included the costs of mineral rights associated with extracting crude oil and natural gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, net of amortization, the Company most likely would be required to reclassify certain amounts out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing full cost accounting rules.

If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, the Company believes that the amount of costs that may be required to be reclassified would be less than $500,000. The Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on compliance with covenants under the Company's debt agreements.

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 or 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.

Risk Factors Related to GMX

There are substantial uncertainties about our current financial condition which curtail our ability to conduct further drilling.

As discussed above, our bank debt matures on September 1, 2004, but our bank has offered to extend the maturity to September 1, 2005, subject to certain conditions. We are actively seeking proposals from other lenders to refinance our existing bank debt to maximize our financial flexibility. In addition, we are dependent on the availability of additional financial resources to pursue further drilling and, accordingly, we may not be able to fully realize the value of our proved undeveloped reserves. Until these uncertainties are resolved, our ability to implement our business plan will continue to be materially adversely affected and our financial condition may be impaired.

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

Ken L. Kenworthy, Jr. and Ken L. Kenworthy, Sr. beneficially own approximately 31% and 15% respectively, of our outstanding common stock. These shareholders, acting together, will be able to control 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 have limited operating history.

We were organized in 1998 and have been in operation for less than seven years. Our limited operating history may not be indicative of our future prospects. We face all of the risks inherent in a new business, including:

- the risk that we will be unable to implement our business plan and achieve our expected financial results;
- the risk that we will be unable to manage growth in our operations by adding personnel, systems and practices necessary to operate a larger business; and
- the risk that, as a small business, we will be subject to market, environmental, regulatory and other developments that we cannot either foresee or control as well as can larger or more established businesses.

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 majority of our common stock, the Kenworthys have appointed the current directors and will have the power to remove and replace directors.

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

To reduce our exposure to fluctuations in the prices of oil and natural gas, we have in the past, and may in the future, enter into hedging arrangements. 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.

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 do not expect 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. We currently are not able to make the necessary capital investment to maintain or expand our oil and natural gas reserves. 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 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 successfully completes Phase I and our current reserve estimates assume that Penn Virginia will complete Phase I and a limited amount of Phase II. Our reserve estimates will be increased if Penn Virginia does not complete Phase I and will be decreased if Penn Virginia fully completes Phase II.

Risks Related to the Oil and Gas Industry

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

Our future financial condition and results of operations are dependent upon the prices we receive for our oil and natural gas production. Oil and natural gas prices historically have been volatile and likely will continue to be volatile in the future. This price volatility also affects our common stock price. In 2002, we received gas and oil prices at the wellhead ranging from $1.23 to $4.68 per Mcf and $15.78 to $29.16 per Bbl. In 2003, we received gas and oil prices ranging from $4.01 to $8.33 per Mcf and $25.72 to $35.08 per Bbl. We cannot predict oil and natural gas prices and prices may decline in the future. The following factors have an influence on oil and natural gas prices:

- relatively minor changes in the supply of and demand for oil and natural gas;
- storage availability;
- weather conditions;
- market uncertainty;
- domestic and foreign governmental regulations;
- the availability and cost of alternative fuel sources;
- the domestic and foreign supply of oil and natural gas;
- the price of foreign oil and natural gas;
- political conditions in oil and natural gas producing regions, including the Middle East; and
- overall economic conditions.

We may encounter difficulty in obtaining equipment and services.

Higher oil and gas prices and increased oil and gas drilling activity, such as those we experienced in 2003, generally stimulate increased demand and result in increased prices and unavailability for drilling rigs, crews, associated supplies, equipment and services. While we are currently experiencing no difficulty obtaining drilling rigs, crews, associated supplies, equipment and services because of a recent decrease in prices and in activity, such difficulty could occur in the future. 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.

Our proved undeveloped reserve estimates are based on the assumption that we can fund the associated development costs. Our ability to fund those costs in the time frames assumed is uncertain and, accordingly, we may not be able to realize the estimated value our proved undeveloped reserves.

We may incur write-downs of the net book values of our oil and gas properties which 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.

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.

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

Not applicable.

Item 8A. CONTROLS AND PROCEDURES

The Company's Principal Executive Officer and Principal Financial Officer have reviewed and evaluated the effectiveness of the Company's 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 the Company's current disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in the reports that it files or submits 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.

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.	47	President, Chief Executive Officer and Director
Ken L. Kenworthy, Sr.	68	Executive Vice President, Secretary, Treasurer, Chief Financial Officer and Director
T. J. Boismier	69	Director
Steven Craig	47	Director
Kyle Kenworthy	42	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.

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

Significant Employees

Keith Leffel, age 54, 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 directors and executive officers of the Company and persons who beneficially own more than 10% of the Company's common stock to file reports of ownership and changes in ownership of the Company's common stock with the Securities and Exchange Commission. The Company is 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 the Company, or written representations that no filings were required, the Company believes that all Section 16(a) filing requirements applicable to its executive officers, directors and 10% shareholders were met during 2003.

Audit Committee Matters

During 2003, the Company had a standing audit committee consisting of Messrs. Boismier and Craig. 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 the Company's audit committee before the adoption of the financial expert rules. The Company is endeavoring to recruit an additional independent board member to satisfy the requirements of the NASDAQ National Market System that the Company have three independent board members on its audit committee and the Company will attempt to recruit a candidate that will also qualify as a "financial expert."

Code of Ethics

The Company has adopted a Code of Business Conduct and Ethics ("Code") that is applicable to all of its officers, directors and employees, including the Company's 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 the chief executive officer of *GMX* and the other executive officers of *GMX.*

Summary Compensation Table

		Annual Compensation			
Name and Principal Position	**Year**	**Salary**	**Bonus**	**Other Annual Compensation**	**All Other Compensation**[1]
Ken L. Kenworthy, Jr.	2001	$171,833	$30,000	–	$5,104
President and Chief Executive	2002	175,000	30,000	–	8,385
Officer	2003	157,500	---	–	---
Ken L. Kenworthy, Sr.	2001	171,833	30,000	–	5,104
Executive Vice President, Secretary,	2002	175,000	30,000	–	8,385
Treasurer and Chief Financial Officer	2003	157,500	---		---
Kyle Kenworthy	2001	56,000	5,000	–	4,070
Vice President--Land	2002	72,000	–	–	5,232

2003	72,000	1,000	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 gasoline allowance for Kyle Kenworthy.

There were no options granted to the named executive officers in 2003. The following table reflects options exercised during 2003 or outstanding at year end for the named executive officers.

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

Name	Shares Acquired on Exercise	Value Realized	Number of Securities Underlying Unexercised Options at December 31, 2003		Value of Unexercised In-the-Money Options at December 31, 2003 (1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Kyle Kenworthy	N/A	N/A	12,500	7,500	N/A	N/A

(1) There was no value of unexercised in-the-money options at December 31, 2003 because the option exercise price exceeded the market price per share of Common Stock on December 31, 2003.

Compensation of Directors

Nonemployee directors, T. J. Boismier and Steven Craig, receive $1,000 for each board and $500 for each committee meeting which they attend. GMX has 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.

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 April 7, 2004, 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 April 7, 2004, there were 6,775,000 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)	928,185	13.7%
Karen Kenworthy(2)(6)	928,157	13.7%
Ken L. Kenworthy, Sr.(2)	967,324	14.3%
Newton Family Group(7)	900,000	13.3%
T. J. Boismier (3)	18,750	*
Steven Craig(4)	5,000	*
Kyle Kenworthy(5)	12,500	*
All executive officers and directors as a group (5 persons)	1,931,759	28.5%

* Less than 1%.

(1) Shares owned by Mr. Kenworthy, Jr. excludes 928,157 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 11,250 shares he has the right to acquire on exercise of options exercisable within 60 days.

(4) Includes 5,000 shares which Mr. Craig has the right to acquire on exercise of options exercisable within 60 days.

(5) Includes 12,500 shares which Mr. Kenworthy has the right to acquire on exercise of options exercisable within 60 days.

(6) Shares owned by Karen Kenworthy excludes 928,185 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 Notwen Corporation, 660 East Broadway, Jackson Hole, Wyoming 83001.

Equity Compensation Plan Information

The following table sets forth information as of December 31, 2003 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	138,000	$3.16	411,000
Equity Compensation Plans Not Approved by Shareholders	75,000	$1.00	--

Item 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

Item 13. EXHIBITS AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

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

(b) The Company filed a report on Form 8-K dated December 20, 2003 reporting under Item 5 execution of a participation agreement with Penn Virginia Oil & Gas Corporation.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following table sets forth the fees billed by the company's independent auditor, KPMG LLP for each of the last 2 years:

	Fees Billed	
Type	**2002**	**2003**
Audit fees (excluding audit related fees)	60,000	65,000
Audit related fees	---	---
Tax fee	---	---
All other fees	---	---

The Audit Committee pre-approves all audit and non-audit services, if any, performed by the independent auditor.There were no audited related tax or other services provided by the independent auditor in 2002 or 2003.

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: April 14, 2004

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	April 14, 2004
/s/ Ken L. Kenworthy, Sr. Ken Kenworthy, Sr.	Executive Vice President, Chief Financial Officer and Director	April 14, 2004
/s/ Steven Craig Steven Craig	Director	April 14, 2004
/s/ T. J. Boismier T. J. Boismier	Director	April 14, 2004

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

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, 2002 and 2003 and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the years 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 generally accepted in the United States of America. 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, 2002 and 2003 and the results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

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, except as to Note L which is as of April 14, 2004

GMX Resources Inc.
Consolidated Balance Sheets
December 31, 2002 and 2003

	2002	2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 543,917	$ 637,522
Accounts receivable—interest owners	52,576	299,442
Accounts receivable--oil and gas revenues	513,898	432,844
Inventories	236,704	235,004
Prepaid expenses and other current assets	11,609	11,608
Total current assets	1,358,704	1,616,420
OIL AND GAS PROPERTIES, AT COST, BASED ON THE FULL COST METHOD OF ACCOUNTING FOR OIL AND GAS PROPERTIES	32,881,893	32,449,096
Less accumulated depreciation, depletion, and amortization	(3,522,584)	(4,788,779)
	29,359,309	27,660,317
OTHER PROPERTY AND EQUIPMENT	3,200,345	3,200,345
Less accumulated depreciation	(656,572)	(991,889)
	2,543,773	2,208,456
OTHER ASSETS	57,646	16,013
TOTAL ASSETS	$ 33,319,432	$ 31,501,206
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 2,426,715	$ 1,134,500
Accrued expenses	81,855	64,887
Accrued interest	6,764	29,703
Revenue distributions payable	407,849	285,382
Derivative financial instruments	421,300	---
Current portion of long-term debt	8,100,000	1,060,000
Total current liabilities	11,444,483	2,610,472
LONG-TERM DEBT, LESS CURRENT PORTION	---	5,630,000
OTHER LIABILITIES	267,486	678,169
DEFERRED INCOME TAXES	---	---
SHAREHOLDERS' EQUITY:		
Common stock, par value $.001 per share—authorized 50,000,000 shares issued and outstanding 6,550, 000 and 6,575,000 shares in 2002 and 2003, respectively	6,550	6,575
Additional paid-in capital	20,905,197	20,959,973
Retained earnings	1,117,016	1,652,017
Other comprehensive income (loss)	(421,300)	---
Total shareholders' equity	21,607,463	22,618,565
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 33,319,432	$ 31,501,206

GMX Resources Inc.
Consolidated Statements of Operations
Years Ended December 31, 2002 and 2003

		2002		2003
REVENUE				
Oil and gas sales	$	5,970,792	$	5,367,370
Interest income		5,169		2,592
Other income		12,381		18,832
Total revenue		5,988,342		5,388,794
EXPENSES				
Lease operations		1,324,481		827,513
Accretion expense on asset retirement obligations		---		22,521
Production and severance taxes		382,826		384,069
Depreciation, depletion and amortization		1,901,976		1,549,678
Interest		510,472		439,313
General and administrative		2,577,388		1,578,865
Total expenses		6,697,142		4,801,959
Income (loss) before income taxes		(708,800)		586,835
INCOME TAX BENEFIT		(263,000)		---
Net income before cumulative effect of a change in accounting principle	$	(445,800)	$	586,835
Cumulative effect of a change in accounting principle		---		(51,834)
Net income (loss)	$	(445,800)	$	535,001
EARNINGS (LOSS) PER SHARE—Before Cumulative Effect	$	(0.07)	$	0.09
EARNINGS (LOSS) PER SHARE – Cumulative Effect	$	---	$	0.01
EARNINGS (LOSS) PER SHARE - Basic and Diluted	$	(0.07)	$	0.08
WEIGHTED AVERAGE COMMON SHARES – Basic and Diluted		6,550,000		6,560,000

See accompanying notes to consolidated financial statements.

GMX Resources Inc.
Consolidated Statement of Changes in Shareholders' Equity
Years Ended December 31, 2003 and 2002

	COMMON STOCK SHARES	COMMON STOCK AMOUNT	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (ACCUMULATED) DEFICIT)	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	TOTAL EQUITY
BALANCE AT DECEMBER 31, 2001	6,550,000	$ 6,550	$ 20,905,197	$ 1,562,816	---	$ 22,474,563
Net income				(445,800)	---	(445,800)
Adjustment for derivative losses reclassified into oil and gas sales	-	-	-	---	423,865	423,865
Change in fair value of derivative instruments	-	-	-	---	(845,165)	(845,165)
Total comprehensive loss	-	-	-	---	---	(867,100)
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 for 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

See accompanying notes to consolidated financial statements.

GMX Resources Inc.
Consolidated Statements of Cash Flows
Years Ended December 31, 2002 and 2003

	2002	2003
CASH FLOWS DUE TO OPERATING ACTIVITIES		
Net income (loss)	$ (445,800)	$ 535,001
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Compensation-stock options	---	29,801
Accretion expense on asset retirement obligations	---	22,521
Depreciation, depletion, and amortization	1,901,976	1,549,678
Deferred income tax benefit	(263,000)	---
Gain on sale of other property and equipment	(3,775)	---
Gain on sale of investments	(3,714)	---
Cumulative effect of change in accounting principle	---	51,834
Decrease (increase) in:		
Accounts receivable	744,636	84,188
Inventory and prepaid expenses	19,874	1,701
Other assets	13,605	41,633
Increase (decrease) in:		
Accounts payable	(4,454,155)	(1,292,215)
Accrued expenses and other liabilities	(123,934)	112,615
Revenue distributions payable	66,648	(122,467)
Net cash provided by (used in) operating activities	(2,547,639)	1,014,290
CASH FLOWS DUE TO INVESTING ACTIVITIES		
Additions to oil and gas properties	(3,014,288)	(236,617)
Purchase of property and equipment	(45,882)	---
Proceeds from sale of other property and equipment	5,000	---
Proceeds from sale of investments	77,838	---
Proceeds from sale of oil and gas properties	4,245,163	700,932
Net cash provided by investing activities	1,267,831	464,315
CASH FLOWS DUE TO FINANCING ACTIVITIES		
Advance on borrowings	5,898,000	---
Payments on debt	(4,078,000)	(1,410,000)
Issuance of equity	-	25,000
Net cash provided by (used in) financing activities	1,820,000	(1,385,000)
Net increase in cash	540,192	93,605
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	3,725	543,917
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 543,917	$ 637,522
CASH PAID FOR INTEREST	$ 510,472	$ 376,585

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 Oklahoma, 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 cost.

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 which GMX also owns an interest in excess of related costs incurred are accounted for as reductions of capitalized costs of oil and gas properties.

The sale of the Company's Kansas properties in September 2002 did not result in a gain or loss. The December 2003 sale of an interest in our East Texas properties also did not result in a gain or loss. All proceeds from the sales 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. SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," was issued in August 2001. This statement addresses financial accounting and reporting for the impairment or long-lived assets. This statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for long-Lived Assets to Be Disposed Of." 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. The Company adopted the statement January 1, 2002 with no material impact on the Company's results of operations or financial position.

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, 2002 or 2003.

CAPITALIZED INTEREST: Interest of $59,195 was capitalized related to the unproved properties that were not being currently depreciated, depleted, or amortized and on which development activities were in progress in 2002.

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 and oil and gas reserve quantities.

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 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. See note I for the fair value of the oil and natural gas price swap agreements.

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 which are dilutive.

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

	2002	2003
Options excluded from dilution calculation	140,000	64,000
Range of exercise prices	\$3.50 - \$8.00	\$3.50 - \$8.00
Weighted average exercise price	\$5.65	\$6.00

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, and has adopted the disclosure requirements of Statement 123 which are included in note F.

Stock option activity for the year ended December 31, 2003 and 2002 is as follows:

	Number of shares		Weighted average exercise price
Balance as of December 31, 2001	150,000	$	5.72
Granted	13,000		3.50
Exercised	—		—
Forfeited	23,000	$	4.42
Expired	—		—
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	$	3.16

At December 31, 2003, 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, 2003, the number of options exercisable was 114,000 and the weighted-average exercise price of those options was $3.63.

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.

		2002		2003
Net (loss) earnings as reported	$	(445,800)	$	535,001
Add: Stock-based compensation recognized		---		29,801
Deduct: Pro forma stock-based compensation, net of tax		(208,387)		(79,081)
Pro forma net (loss) earnings		(654,187)		485,721

For 2002, 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 1.73%, expected volatility of 1.31%, 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 2002.

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 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.

	Year Ended December 31, 2003
Beginning of the period	$ —
Initial adoption entry	281,516
Liabilities incurred in the current period	—
Liabilities settled in the current period	—
Accretion expense	22,521
End of the period	$ 304,037

The pro forma effects on prior periods were not material.

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 December 2003, the FASB issued FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. FIN 46R replaces FASB Interpretation No. 46, Consolidation of Variable Interest Entities, which was issued in January 2003. The Company will be required to apply FIN 46R to variable interests in VIEs created after December 31, 2003. For variable interests in VIEs created before January 1, 2004, the Interpretation will be applied beginning on January 1, 2005. For any VIEs that must be consolidated under FIN 46R that were created before January 1, 2004, the assets, liabilities and noncontrolling interests of the VIE initially would be measured at their carrying amounts with any difference between the net amount added to the balance sheet and any previously recognized interest being recognized as the cumulative effect of an accounting change. If determining the carrying amounts is not practicable, fair value at the date FIN 46R first applies may be used to measure the assets, liabilities and noncontrolling interest of the VIE. The Company anticipates that this standard will not have an impact on the Company's financial statements because it does not own any interests in variable interest entities.

SFAS Statement of 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity, ("SFAS 150") was issued in May, 2003. SFAS 150 establishes standards for the classification and measurement of certain financial instruments with characteristics of both liabilities and equity. SFAS 150 also includes required disclosures for financial instruments within its scope. SFAS 150 was effective for instruments entered into or modified after May 31, 2003 and otherwise will be effective as of January 1, 2004, except for mandatorily redeemable financial instruments. For certain mandatorily financial instruments, FSAS 150 will be effective on January 1, 2005. The effective date has been deferred indefinitely for certain other types of mandatorily redeemable financial instruments. The Company currently does not have any financial instruments that are within the scope of SFAS 150.

During 2003, a reporting issue arose regarding the application of certain provisions of SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting crude oil and natural gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. The EITF has added the treatment of oil and gas mineral rights to an upcoming agenda, which may result in a change in how GMX classifies these assets. Historically, the Company has included the costs of mineral rights associated with extracting crude oil and natural gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, net of amortization, the Company most likely would be required to reclassify certain amounts out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with existing full cost accounting rules.

If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting crude oil and natural gas as a separate intangible assets line item on the balance sheet, the Company believes that the amount of costs that may be required to be reclassified would be less than $500,000. The Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on compliance with covenants under the Company's debt agreements.

NOTE B--PROPERTY AND EQUIPMENT

Property and equipment included the following:

	December 31, 2002	December 31, 2003
Oil and gas properties:		
Subject to amortization	$ 31,710,171	$ 31,219,309
Not subject to amortization:		
Acquired in 2003	---	57,565
Acquired in 2002	76,829	76,829
Acquired in 2001	853,258	853,258
Acquired in 2000	93,195	93,195
Acquired in 1999	---	---
Acquired in 1998	148,940	148,940
Accumulated depreciation, depletion, and amortization	(3,522,584)	(4,930,779)
Net oil and gas properties	29,359,809	27,518,317
Other property and equipment	3,200,345	3,200,345
Less accumulated depreciation	(656,572)	(991,889)
Net other property and equipment	2,543,773	2,208,456
Property and equipment, net of accumulated Depreciation, depletion, and amortization	$ 31,903,582	$ 29,726,773

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

	For The Year Ended December 31, 2002	For The Year Ended December 31, 2003
Depreciation, depletion, and amortization of oil and gas properties	$ 1,557,930	$ 1,214,361
Depreciation of other property and equipment	344,046	335,317
Total	$ 1,901,976	$ 1,549,678

NOTE C--LONG-TERM DEBT

	December 31, 2002	December 31, 2003
Note payable to bank, maturity date of May 1, 2003, bearing a variable interest rate (4.75% and 5.25% as of December 31, 2001 and 2002, respectively) collateralized by producing oil and gas properties	$ 8,100,000	$ 6,690,000
	8,100,000	6,690,000
Current portion	(8,100,000)	(1,060,000)
Long Term	$ ---	$ 5,630,000

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 plus 1%. 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. The credit facility matured in May 2003 and we remained in default under the facility until August 2003 when the credit facility was amended to extend the maturity date of the promissory note from May 1, 2003 to new maturity date of March 1, 2004. On March 15, 2004, the bank approved an extension of the existing credit facility with the following amended terms: New maturity date of September 1, 2004, Borrowing Base of $6,310,000, monthly commitment reduction of $90,000 and all other terms in the existing credit agreement to remain unchanged. At December 31, 2003, the Company had borrowed $6,690, 000 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. See Note L.

Subordinated Notes

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 will increase 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 are permitted in 2005 and 2006 subject to certain conditions being met under the terms of the credit facility agreements.

The Company is obligated to register the warrants and underlying shares of common stock under the Securities Act of 1933 on or before June 30, 2004 in order to permit the holders to sell the warrants and underlying shares without restrictions. If the Company fails to effect or maintain such registration, it is obligated to issue additional warrants at the rate of 10,000 warrants per month such failure exists.

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, 2003, the Company had the following carryforwards available to reduce future income taxes:

Federal	$	21,141,000
States		7,234,000
Statutory depletion		2,575,000

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, 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 gross deferred tax asset of $8,498,000 was primarily the result of the Company's net operating loss and statutory depletion carryforwards. As of December 31, 2003, the Company recognized a valuation allowance of $602,000. Management of the Company determined that based upon current taxable income and financial conditions that it is not more likely than not that the Company will be able to utilize all of its net operating loss carryforwards prior to their expiration.

	December 31,	
	2002	2003
Deferred tax assets:		
Net operating loss carry forwards	7,712,000	7,622,000
Statutory depletion carry forwards	638,000	876,000
Total	8,350,000	8,498,000
Deferred tax liability:		
Property, plant and equipment	(8,060,000)	(7,896,000)
Valuation allowance	(290,000)	(602,000)
Total	(8,350,000)	(8,498,000)
Net deferred tax asset	----	---

As of December 31, 2002, the Company's deferred tax liability of $8,060,000 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 $8,350,000 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,	
	2002	2003
U.S. statutory tax rate	34%	34%
Statutory depletion	(34)	(93)
Change in valuation allowance	41	58
Other	(4)	1
Effective income tax rate	37	-

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, 2003.

Year Ending December 31:

2004	$	162,129
2005		110,091
2006		110,091
Total	$	382,311

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

2002	$	97,298
2003		195,468

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. No options were outstanding at December 31, 2000.

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 addition on April 5, 2004, the Company closed a private placement of 200,000 shares of common stock for $1,000,000 with an investor. Proceeds of the transaction will be used for general corporate purposes.

On February 12, 2001, the Company sold 1,250,000 units at a price of $8 per unit and received approximately $8,550,000 in proceeds, net of commissions and offering expenses. The units consisted of 1,250,000 shares of common stock, 1,250,000 class A warrants, and 1,250,000 class B warrants. The class A warrants allow holders to purchase common shares of the Company for $9.00 per share prior to March 12, 2002 and $12.00 per share thereafter. The class B warrants allow holders to purchase common shares of the Company for $10.00 per share. The class A warrants expire on February 12, 2006 and the class B warrants expired on February 12, 2003. The Company used a portion of the proceeds of the offering to repay $427,500 of loans from shareholders.

On July 17, 2001 and July 25, 2001, GMX sold 2,000,000 and 300,000 common shares, respectively, at a price of $5.50 per share. Proceeds to GMX, net of underwriters' fees and other expenses, were $11,285,544. GMX has also granted the underwriters five-year warrants to purchase up to 200,000 shares for $6.60 per common share.

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, 2002 and 2003 were as follows:

	2002	2003
Teppco Crude	95%	99%
CrossTex Energy Services, Inc.	77%	83%

NOTE H—DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

During 2002 and 2003, the Company utilized swap arrangements to hedge a portion of its exposure to price volatility from producing natural gas. Each swap arrangement established a price above which the Company paid the counterparty and below which the Company was paid. Results from commodity hedging transactions are reflected in gas sales.

The Company entered into natural gas price swaps that initiated in March 2002 and expired in February 2003. These agreements relate to 50,000 and 40,000 mmbtu whereby the Company will receive a fixed price of $2.66 and $2.67 per mmbtu, respectively and pay the counterparty an index price. Payments by the Company in 2002 totaled $652,100 and $438,400 in 2003.

There were no outstanding financial instruments as of December 31, 2003.

GMX's derivatives qualified for hedge accounting treatment that is considered a "cash flow" hedge. GMX designates its cash flow hedge derivatives as such on the date the derivative contract is entered into.

By using derivative instruments to hedge exposures to changes in commodity prices, GMX exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. To mitigate this risk, the hedging instruments are usually placed with counterparties that GMX believes are minimal credit risks.

Market risk is the adverse effect on the value of a derivative instrument that results from a change in interest rates or commodity prices. The market risk associated with commodity price is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

GMX periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through various financial transactions to manage its exposure to oil and gas price volatility. These transactions include financial price swaps whereby GMX will receive a fixed price for its production and pay a variable market price to the contract counterparty. These financial hedging activities are intended to support oil and natural gas prices at targeted levels and to manage GMX's exposure to oil and gas price fluctuations. The oil and gas reference prices upon which these price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by GMX.

GMX does not hold or issue derivative instruments for trading purposes. All of GMX's commodity price financial swaps in place at January 1, 2003 were designated as cash flow hedges. Changes in the fair value of these derivatives were reported in "Accumulated other comprehensive income." These amounts were reclassified to oil and gas sales when the forecasted transaction took place.

NOTE I--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 J--OIL AND GAS OPERATIONS (Unaudited)

Capitalized costs related to the Company's oil and gas producing activities as of December 31, 2002 and 2003 are:

	2002	2003
Unproved properties	$ 1,171,722	$ 1,229,787
Producing properties	31,710,171	31,219,309
	32,881,893	32,449,096
Less accumulated depreciation, depletion, and Amortization	(3,522,584)	(4,788,779)
Net capitalized costs	$ 29,359,309	$ 27,660,317

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 2002 and 2003 are as follows:

	2002	2003
Property acquisition costs – proved	$ 120,157	$ 57,575
Property acquisition costs – unproved	84,672	5,212
Development costs	2,812,876	175,840
	$ 3,017,705	$ 238,627

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 2002 and 2003 include revenues and expenses associated directly with oil and gas producing activities.

	2002	2003
Oil and gas sales	$ 5,970,792	$ 5,367,370
Production costs	1,707,307	1,211,582
Depreciation, depletion and amortization	1,557,930	1,214,779
Income tax expense	665,000	733,670
Results of operations for oil and gas producing activities	$ 2,040,555	$ 2,207,339

NOTE K--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, 2002 and 2003, all of the Company's oil and gas reserves were located in the United States.

	OIL (MBBLS)	GAS (MMCF)
December 31, 2002		
Proved reserves, beginning of period	3,862	68,611
Extensions, discoveries, and other additions	---	---
Production	(70)	(1,639)
Sale of reserves in-place	(1,218)	(2,263)
Revisions of previous estimates	(910)	(8,027)
Proved reserves, end of period	1,664	(56,682)
Proved developed reserves:		
Beginning of period	1,018	15,352
End of period	604	16,501
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

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, 2002 (In thousands)	December 31, 2003 (In thousands)
Future cash inflows	$ 294,669	$ 300,514
Future production costs	(68,815)	(77,608)
Future development costs	(39,518)	(44,557)
Future income tax provisions	(60,799)	(58,158)
Net future cash inflows	125,537	120,191
Less effect of a 10% discount factor	(71,225)	(72,216)
Standardized measure of discounted future net cash flows	$ 54,312	$ 47,975

Oil and condensate prices were based on an equivalent base price of $32.52 per barrel for benchmark posted West Texas Intermediate Crude Oil at closing on December 31, 2003. 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 $32.04 per barrel. Natural gas prices were based on an equivalent base price of $6.187 per million British thermal unit (mmbtu) for the composite Henry Hub Spot Market benchmark price at closing on December 31, 2003. 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 $5.73 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, 2002		December 31, 2003
Standardized measure, beginning of year	$	48,524	$	54,312
Sales of oil and gas, net of production costs		(2,508)		(4,156)
Net changes in prices and production costs		51,708		11,782
Extensions and discoveries, net of future development costs		---		---
Development costs that reduced future development costs		2,091		---
Revisions of quantity estimates		(20,447)		646
Sales of reserves in place		(15,192)		(16,434)
Accretion of discount		7,095		8,061
Other		(13,084)		(9,322)
Net changes in income taxes		(3,875)		3,086
Standardized measure, end of year	$	54,312	$	47,975

NOTE L--MANAGEMENT'S PLANS

The Company reached a drilling arrangement with Penn Virginia Oil & Gas Corporation ("PVOG") in December of 2003 relating to the joint development of its east Texas properties. As a result of that agreement, the Company has a 20% carried interest in the first five wells that are drilled in Phase I. The Company then has the option, but not the obligation, to participate in any remaining Phase I wells for a 30% interest. As a result of this agreement, the Company has reduced its cost and ownership related to the development of these wells. In addition, subsequent to December 31, 2003, the Company has raised $1,000,000 of subordinated debt and $1,000,000 of equity to date in 2004 for recompletion and other corporate activities. As a result of the increased 2004 production levels and, to a lesser extent, increased commodity prices, the Company has been able to extend the maturity of its existing credit facility to September 1, 2004. The Company has also received term sheets from other lenders to refinance the credit facility, increase the borrowing base, and extend the maturity date. On April 14, 2004, the Company received a formal commitment from its current lender to extend the maturity date to September 1, 2005, subject to the Company's applying the proceeds of its recent common stock private placement to prepayment of the 11% subordinated notes on or before May 14, 2004. The Company will continue to evaluate the other lenders' terms to maximize its flexibility before accepting this proposal. The Company is also considering additional issuances of subordinated debt or equity to provide additional funds for drilling plans. If the Company is unable to raise additional subordinated debt or equity and unable to increase or extend its credit facility beyond September 2005, the Company would be unlikely to be able to participate in additional drilling.