ARENA RESOURCES INC
Form 10-K
March 16, 2006

United States Securities and Exchange Commission

Washington, D.C. 20549

Form 10-K

(Mark One)

|X| Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2005
Or
|__| Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ___________to ___________

Commission file number 001-31657

Arena Resources, Inc.

(Exact name of registrant as specified in its charter)

Nevada	**73-1596109**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
4920 South Lewis Avenue, Suite 107 **Tulsa, Oklahoma**	**74105**
(Address of principal executive offices)	(Zip Code)

(918) 747-6060
(Registrant's telephone number, including area code)

Securities registered under Section 12(b) of the Exchange Act:

Title of Each Class	Name of Each Exchange On Which Registered
Common - $0.001 Par Value	American Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes |_| No |X|

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

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

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

10-K or any amendment to this Form 10-K. |**X**|

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer.

Large accelerated filer |_| Accelerated filer |**X**| Non-accelerated filer |_|

Indicate by check mark whether the registrant is shell company (as defined in Rule 12b-2 of the Act). Yes |_| No |**X**|

As of June 30, 2005, the aggregate market value of the common voting stock held by non-affiliates of the issuer, based upon the closing stock price of $11.95 per share, was approximately $98,311,108.

As of February 28, 2006, the issuer had outstanding 13,226,702 shares of common stock ($0.001 par value).

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PART I

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Forward Looking Statements

All statements, other than statements of historical fact included in this Annual Report on Form 10-K (herein, Annual Report) regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words could, believe, anticipate, intend, estimate, expect, project similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. All forward-looking statements speak only as of the date of this Annual Report. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Unless the context otherwise requires, references in this Annual Report to Arena, we, us, our or ours refer to Arena Resources, Inc.

PART I

Item 1: **Description of Business**

General

Arena Resources, Inc. was incorporated in Nevada on August 31, 2000. Our principal executive offices are located at 4920 South Lewis Avenue, Suite 107, Tulsa, Oklahoma 74105, and our telephone number is (918) 747-6060, and our Internet website can be found at www.arenaresourcesinc.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act of 1934 will be available through our Internet website as soon as reasonably practical after we electronically file such material with, or furnish it to, the Securities and Exchange Commission.

We are engaged in oil and natural gas acquisition, exploration, development and production, with activities currently in Oklahoma, Texas, New Mexico and Kansas. Our focus will be on developing our existing properties, while continuing to pursue acquisitions of oil and gas properties with upside potential.

Business Development

Since our inception in August 2000, we have built our asset base and achieved growth primarily through property acquisitions. From our inception through December 31, 2005, we have increased our proved reserves to approximately 30.2 million Boe (barrel of oil equivalent). As of December 31, 2005, our estimated proved reserves had a pre-tax PV10 (present value of future net revenues before income taxes discounted at 10%) of approximately $683 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $446 million. The difference between these two amounts is the effect of income taxes. The Company presents the pre-tax PV-10 value, which is a non-GAAP financial measure, because it is a widely used industry standard which we believe is useful to those who may review this Annual Report when comparing our asset base and performance to other comparable oil and gas exploration and production companies. We spent approximately $64 million on acquisitions and capital projects during 2003, 2004 and 2005.

We have a portfolio of oil and natural gas reserves, with approximately 82% of our proved reserves consisting of oil and approximately 18% consisting of natural gas. Of those reserves approximately 26% of our proved reserves are classified as proved developed producing, or PDP, approximately 4% of our proved reserves are classified as proved developed non-producing, or PDNP, approximately 8% are classified as proved developed behind pipe PDBP, and approximately 62% are classified as proved undeveloped, or PUD.

Competitive Business Conditions

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. The majority of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Current competitive factors in the domestic oil and gas industry are unique. The actual price range of crude oil is largely established by major international producers. Pricing for natural gas is more regional. Because the current domestic demand for oil and gas exceeds supply, we believe there is little risk that all current production will not be sold at relatively fixed prices. To this extent we do not believe we are directly competitive with other producers, nor is there any significant risk that we could not sell all our current production at current prices with a reasonable profit margin. The risk of domestic overproduction at current prices is not deemed significant. However, more favorable prices can usually be negotiated for larger quantities of oil and/or gas product. In this respect, while we believe we have a price disadvantage when compared to larger producers, we view our primary pricing risk to be related to a potential decline in international prices to a level which could render our current production uneconomical.

We are presently committed to use the services of the existing gathering companies in our present areas of production. This potentially gives such gathering companies certain short-term relative monopolistic powers to set gathering and transportation costs, because obtaining the services of an alternative gathering company would require substantial additional costs (since an alternative gathering company would be required to lay new pipeline and/or obtain new rights of way to any lease from which we are selling production).

Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For fiscal year 2005, two customers were responsible for generating 84% or more of our total oil and natural gas sales. These two customers were Plains Marketing, L.P., accounting for approximately 12% of total sales and Navajo Refining Company, accounting for approximately 72% of total sales. However, we believe that the loss of either of these customers would not materially impact our business, because we could readily find other purchasers for our oil and gas as produced.

Governmental Regulations

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state.

Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors. Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

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

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

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

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Compliance and Risks

Our oil and natural gas exploration, development and production operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Historically, most of the environmental regulation of oil and gas production has been left to state regulatory boards or agencies in those jurisdictions where there is significant gas and oil production, with limited direct regulation by such federal agencies as the Environmental Protection Agency. However, while we believe this generally to be the case for our production activities in Oklahoma, Texas, New Mexico and Kansas, there are various regulations issued by the Environmental Protection Agency (EPA) and other governmental agencies that would govern significant spills, blow-outs, or uncontrolled emissions.

In Oklahoma, Texas, New Mexico and Kansas specific oil and gas regulations apply to the drilling, completion and operations of wells, and the disposal of waste oil and salt water. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency.

At the federal level, among the more significant laws and regulations that may affect our business and the oil and gas industry are: The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as CERCLA or Superfund; the Oil Pollution Act of 1990; the Resource Conservation and Recovery Act, also known as RCRA, ; the Clean Air Act; Federal Water Pollution Control Act of 1972, or the Clean Water Act; and the Safe Drinking Water Act of 1974.

Compliance with these regulations may constitute a significant cost and effort for us. No specific accounting for environmental compliance has been maintained or projected by us at this time. We are not presently aware of any environmental demands, claims, or adverse actions, litigation or administrative proceedings in which either us or our acquired properties are involved or subject to, or arising out of any predecessor operations.

In the event of a breach of environmental regulations, these environmental regulatory agencies have a broad range of alternative or cumulative remedies which include: ordering a clean-up of any spills or waste material and restoration of the soil or water to conditions existing prior to the environmental violation; fines; or enjoining further drilling, completion or production activities. In certain egregious situations the agencies may also pursue criminal remedies against us or our principal officers.

Current Employees

As of December 31, 2005, we had twenty-two full-time employees, including three petroleum engineers. Our employees are not represented by any labor union. We consider our relations with our employees to be satisfactory and have never experienced a work stoppage or strike.

We retain certain engineers, geologists, landmen, pumpers and other personnel on a contract or fee basis as necessary for our operations.

Item 1A: **Risk Factors**

The following risks and uncertainties may affect our performance, results of operations and trading price of our common stock.

Risks Relating to the Oil and Natural Gas Industry and Our Business

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

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

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

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices will also negatively impact the value of our proved reserves. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

A substantial percentage of our proven properties are undeveloped; therefore the risk associated with our success is greater than would be the case if the majority of our properties were categorized as proved developed producing.

Because a substantial percentage of our proven properties are proved undeveloped (approximately 62%), or proved developed non-producing (approximately 4%), we will require significant additional capital to develop such properties before they may become productive. Further, because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be developed to the extent that they result in positive cash flow. Even if we are successful in our development efforts, it could take several years for a significant portion of our undeveloped properties to be converted to positive cash flow.

While our current business plan is to fund the development costs with cash flow from our other producing properties, if such cash flow is not sufficient we may be forced to seek alternative sources for cash, through the issuance of additional equity or debt securities, increased borrowings or other means.

Approximately 38% of our proven reserves depend upon secondary recovery techniques to establish production.

Approximately thirty-eight percent (38%) of our reserves for the year ended December 31, 2005 are associated with secondary recovery projects that are either in the initial stage of implementation or are scheduled for implementation. We anticipate that secondary recovery will be attempted by the use of waterflood of these reserves, and the exact project initiation dates and, by the very nature of waterflood operations, the exact completion dates of such projects, are uncertain. In addition, the reserves associated with these secondary recovery projects, as with any reserves, are estimates only, as the success of any development project, including these waterflood projects, cannot be ascertained in advance. If we are not successful in developing a significant portion of our reserves associated with secondary recovery methods, it could have a negative impact on our earnings and our stock price.

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read Reserve estimates depend on many assumptions that may turn out to be inaccurate (below) for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

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

If our assessments of recently purchased properties are materially inaccurate, it could have significant impact on future operations and earnings.

We have aggressively expanded our base of producing properties. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. As noted previously, we plan to undertake further development of our properties through the use of cash flow from existing production. Therefore, a material deviation in our assessments of these factors could result in less cash flow being available for such purposes than we presently anticipate, which could either delay future development operations (and delay the anticipated conversion of reserves into cash), or cause us to seek alternative sources to finance development activities.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties, potentially requiring earlier than anticipated debt repayment and negatively impacting the trading value of our securities.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. Because our properties serve as collateral for advances under our existing credit facilities, a write-down in the carrying values of our properties could require us to repay debt earlier than we would otherwise be required. A write-down could also constitute a non-cash charge to earnings. It is likely the cumulative effect of a write-down could also negatively impact the trading price of our securities.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reported reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reported reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reported proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If future values decline or costs increase it could negatively impact our ability to finance operations, and individual properties could cease being commercially viable, affecting our decision to continue operations on producing properties or to attempt to develop properties. All of these factors would have a negative impact on earnings and net income, and most likely the trading price of our securities. These factors could also result in the acceleration of debt repayment and a reduction in our borrowing base under our credit facilities.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our prospects are in various stages of evaluation, ranging from prospects that are currently being drilled, to prospects that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. This risk may be enhanced in our situation, due to the fact that a significant percentage (62%) of our proved reserves are currently proved undeveloped reserves. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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

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

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

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

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- discharge permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- unitization and pooling of properties; and
- taxation.

Under these laws, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, incurrence of investigatory or remedial obligations or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition as well as the industry in general. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed.

If our indebtedness increases, it could reduce our financial flexibility.

We have a $50 million credit facility in place with a current borrowing base of $35 million. If in the future we utilize this facility, the level of our indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flow could be used to service the indebtedness,
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions,
- the covenants contained in our credit facility limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments,
- a high level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

In addition, our bank borrowing base is subject to semi-annual redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

The loss of senior management could adversely affect us.

To a large extent, we depend on the services of our senior management. The loss of our senior management Stanley McCabe, our Chairman, or Tim Rochford, our President and Chief Executive Officer could have a material adverse effect on our operations. While we have obtained key man life insurance policies on Mr. Rochford, any amounts that we may recover under such policy may not adequately compensate us for the loss of the services of Mr. Rochford. We do not have employment agreements with either Mr. McCabe or Mr. Rochford.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

With the recent increase in the prices of oil and natural gas, we have encountered an increase in the cost of securing drilling rigs, equipment and supplies. Shortages or the high cost of drilling rigs, equipment, supplies and personnel are expected to continue in the near-term. In addition, larger producers may be more likely to secure access to such equipment by virtue of offering drilling companies more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, not only would this potentially delay our ability to convert our reserves into cash flow, but could also significantly increase the cost of producing those reserves, thereby negatively impacting anticipated net income.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business.

Currently, the majority of our production is sold to marketers and other purchasers that have access to nearby pipeline facilities. However, as we begin to further develop our properties, we may find production in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil or natural gas have several adverse affects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Risks Relating to Our Common Stock

The market price of our stock may be affected by low volume float

While there has been a public market for our common stock on the American Stock Exchange, in the last twelve months the daily trading volume, or public float , of our common stock has ranged from as low as 4,500 shares to as high as 524,600 shares. The average volume of shares traded during the 90 days prior to December 31, 2005 was 796,854 shares per week.

Additionally, approximately 1,856,942 shares of our common stock are restricted shares under Rule 144, but could be currently sold with little difficulty under the provisions of Rule 144(k). We also estimate that approximately 1,030,261 additional shares of common stock that are currently restricted , will soon be capable of being resold under Rule 144.

Finally, as of December 31, 2005 there are warrants outstanding to purchase 368,126 shares of common stock, as well as options to purchase 1,425,000 shares of common stock (of which options to acquire 400,000 shares are currently exercisable, with 400,000 options vesting over the next two and one-half years, and the balance vesting over the next four and one-half years).

Substantial sales of our common stock, including shares issued upon the exercise of outstanding options and warrants, in the public market, or the perception that these sales could occur, may have a depressive effect on the market price of our common stock. Such sales or the perception of such sales could also impair our ability to raise capital or make acquisitions through the issuance of our common stock.

We have no plans to pay dividends on our common stock. You may not receive funds without selling your shares.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, our credit facility prohibits us from paying dividends.

Provisions under Nevada law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

While we do not believe that we currently have any provisions in our organizational documents that could prevent or delay a change in control of our company (such as provisions calling for a staggered board of directors, or the issuance of stock with super-majority voting rights), the existence of some provisions under Nevada law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. Nevada law imposes some restrictions on mergers and other business combinations between us and any holder of 10% or more of our outstanding common stock.

Item 1B: Unresolved Staff Comments

None.

Item 2: Description of Property

General Background

Since our inception in late August 2000, we have begun to build a solid asset base and achieved steady growth, primarily through property acquisitions, but with some exploitation activities. From our inception through December 31, 2005, our proved reserves have grown to 30,197,536 Boe, at an average acquisition/drilling cost of $2.21 per Boe. Many properties contain both oil and gas reserves. In those cases, the oil and gas reserves and the volume of oil and gas produced are converted to a common unit of measure on the basis of their approximate relative energy content. The common unit which we use is Barrels of oil equivalent or Boe. Acquisition and drilling costs per Boe is calculated by dividing the net capitalized costs ($66,748,047), computed in accordance with applicable accounting standards, as shown under Capitalized Costs Relating to Oil and Gas Producing Activities under Supplemental Information on Oil and Gas Producing Activities, by our reserves in Boe (30,197,536).

As of December 31, 2005, our estimated proved reserves had a pre-tax PV10 value of approximately $683 million and a Standardized Measure of Discounted Future Cash Flows of approximately $446 million, approximately 31% of which came from properties located in New Mexico, approximately 56% from our properties in Texas, approximately 9% from our properties in Oklahoma and approximately 4% from our properties in Kansas. We spent approximately $64 million on capital projects during 2003, 2004 and 2005. We expect to further develop these properties through additional drilling. Our capital budget for 2006 is approximately $61 million for development of existing properties. Although our focus will be on development of our existing properties, we also intend to continue seeking acquisition opportunities which compliment our current portfolio. We intend to fund our development activity primarily through use of cash flow from operations and cash on hand, while potential drawings on our credit facility and proceeds from future equity transactions would also be available for development projects or future acquisitions. We believe that our acquisition expertise, together with our operating experience and efficient cost structure, provides us with the potential to continue our growth.

The following table summarizes our total net proved reserves, pre-tax PV10 value and Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2005.

Geographic Area	Oil (Bbl)	Natural Gas (Mcf)	Total (Boe)	Pre-Tax PV10 Value	Standardized Measure of Discounted Future Net Cash Flows
New Mexico	9,312,749	4,922,009	10,133,084	$ 216,465,799	$ 136,639,312
Texas	12,375,123	19,892,629	15,690,561	380,356,600	251,524,556
Oklahoma	3,179,317	324,446	3,233,392	62,283,381	41,655,077
Kansas	--	6,842,995	1,140,499	23,855,051	15,781,621
Total	24,867,189	31,982,079	30,197,536	$ 682,960,831	$ 445,600,566

Proved Reserves

Our 30,197,536 Boe of proved reserves, which consist of approximately 82% oil and 18% natural gas, are summarized below as of December 31, 2005, on a net pre-tax PV10 value and Standardized Measure of Discounted Future Net Cash Flows basis. Our reserve estimates have not been filed with any Federal authority or agency (other than the SEC).

As of December 31, 2005, New Mexico proved reserves had a net pre-tax PV10 value of $216.5 million and Standardized Measure of Discounted Future Net Cash Flows of $136.6 million, our proved reserves in Texas had a net pre-tax PV10 value of $380.4 million and Standardized Measure of Discounted Future Net Cash Flows of $251.5 million, our proved reserves in Oklahoma had a net pre-tax PV10 value of $62.3 million and a Standardized Measure of Discounted Future Net Cash Flows of $41.7 million and our proved reserves in Kansas had a net pre-tax PV10 value of $23.9 million and a Standardized Measure of Discounted Future Net Cash Flows of $15.8 million.

As of December 31, 2005, approximately 26% of the 30.2 million Boe of proved reserves have been classified as proved developed producing, or PDP . Proved developed non-producing, or PDNP reserves constitute approximately 4%, proved developed behind-pipe PDBP reserves constitute approximately 8% and proved undeveloped, or PUD , reserves constitute approximately 62%, of the proved reserves as of December 31, 2005.

Approximately thirty-eight percent (38%) of our reserves for the year ended December 31, 2005 are associated with secondary recovery projects that are either in the initial stage of implementation or are scheduled for implementation. We anticipate that secondary recovery will be attempted by the use of waterflood of these reserves, and the exact project initiation dates and, by the very nature of waterflood operations, the exact completion dates of such projects, are uncertain.

Total proved reserves had a net pre-tax PV10 value as of December 31, 2005 of approximately $683 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $446 million, 25.8% or $145.5 million and $94.5, respectively, of which is associated with the PDP reserves. An additional $39.2 million and $25.9 million, respectively, is associated with the PDNP reserves and $53.1 million and $34.9 million, respectively, is associated with PDBP reserves ($237.8 million and $155.3 million, respectively, for total proved developed reserves, or 38.5% of total proved reserves pre-tax PV10 value). The remaining $445.2 million and $290.4 million, respectively, is associated with PUD reserves.

Our proved reserves as of December 31, 2005 are summarized in the table below.

	Oil (Bbl)	Gas (Mcf)	Total (Boe)	% of Total Proved	Pre-tax PV10 (In thousands)	Standardized Measure of Discounted Future Net Cash Flows	Future Capital Expenditures (In thousands)
New Mexico:							
PDP	3,165,117	2,976,114	3,661,136	12%	$ 59,972	$ 37,856	$ -
PDNP	59,301	80,056	72,644	0%	2,600	1,641	318
PDBP	326,902	250,734	368,691	1%	7,438	4,695	33
PUD	5,761,429	1,615,105	6,030,613	20%	146,456	92,447	14,431
Total Proved:	9,312,749	4,922,009	10,133,084	33%	$ 216,466	$ 136,639	$ 14,782
Texas:							
PDP	2,977,483	1,704,167	3,261,511	11%	$ 68,816	$ 45,507	$ -
PDNP	702,863	383,558	766,789	3%	28,852	19,079	4,160
PDBP	-	13,701,828	2,283,638	8%	45,703	30,223	4,140
PUD	8,694,777	4,103,076	9,378,623	31%	236,986	156,716	65,209
Total Proved:	12,375,123	19,892,629	15,690,561	53%	$ 380,357	$ 251,525	$ 73,509
Oklahoma:							
PDP	525,336	108,825	543,474	3%	$ 8,924	$ 5,968	$ -
PDNP	128,113	-	128,113	0%	3,257	2,178	-
PUD	2,525,868	215,621	2,561,805	7%	50,102	33,509	6,575
Total Proved:	3,179,317	324,446	3,233,392	10%	$ 62,283	$ 41,655	$ 6,575
Kansas:							
PDP	-	1,962,997	327,166	1%	$ 7,761	$ 5,135	$ -
PDNP	-	1,312,000	218,667	1%	4,486	2,968	-
PUD	-	3,567,998	594,666	2%	11,608	7,679	900
Total Proved:	-	6,842,995	1,140,499	4%	$ 23,855	$ 15,782	$ 900
Total:							
PDP	6,667,936	6,752,103	7,793,287	26%	$ 145,473	$ 94,466	$ -
PDNP	890,277	1,775,614	1,186,213	4%	39,195	25,866	4,478
PDBP	326,902	13,952,562	2,652,329	9%	53,141	34,918	4,173
PUD	16,982,074	9,501,800	18,565,707	62%	445,152	290,351	87,115
Total Proved:	24,867,189	31,982,079	30,197,536	100%	$ 682,961	$ 445,601	$ 95,766

Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves

The following table indicates projected reserves that we currently estimate will be converted from proved undeveloped to proved developed, as well as the estimated costs per year involved in such development.

Year	Estimated Oil Reserves Developed (Bbls)	Estimated Gas Reserves Developed (Mcf)	Total Boe	Estimated Development Costs
2006	11,615,519	6,643,650	12,722,794	$ 52,044,584
2007	5,366,554	2,858,155	5,842,913	35,070,440
	16,982,073	9,501,805	18,565,707	$ 87,115,024

Production

Our estimated average daily production for the month of December, 2005, is summarized below. These tables indicate the percentage of our estimated December 2005 average daily production of 2,050 Boe/d attributable to each state and to oil versus natural gas production.

State	Average Daily Production	Oil	Natural Gas
New Mexico	29.48%	25.46%	4.02%
Texas	60.30%	55.32%	4.98%
Oklahoma	8.05%	7.48%	0.57%
Kansas	2.18%	0.00%	2.18%
Total	100%	88%	12%

Summary of Oil and Natural Gas Properties and Projects

Significant New Mexico Operations

East Hobbs Unit Lea County, New Mexico. In May 2004 we acquired a 82.24% working interest and a 67.6% net revenue interest in this lease primarily from EnerQuest Oil and Gas, Ltd., an unaffiliated company, for a cash payment of $10,008,440. Net revenue interest is the owner s percentage share of the monthly income realized from the sale of a well s produced oil and gas. The net revenue interest is a lesser number as compared to the working interest, due to the mineral owner royalty and other overriding royalties on the well. Although the Purchase and Sales Agreement transferred the revenue and the related operating costs from East Hobbs to us beginning March 1, 2004, Arena did not control the property interests until May 7, 2004. As a result, the acquisition date for accounting purposes was May 7, 2004 and the operations of East Hobbs operations were included in our results of operations from May 7, 2004. Revenues and operating costs for the months of March and April were estimated and treated as adjustments to the purchase price. This lease covers approximately 920 acres. There are currently 28 producing wells. We believe this property can support a number of additional wells, four of which are included in our estimate of PUD. This lease is held by production.

Seven Rivers Queen Unit Lea County, New Mexico. We acquired a 70.6% working interest and a 56.48% net revenue interest in this property in May 2003. This lease was acquired from Permian Resources Holding, Inc., an unaffiliated company, for a cash payment of $900,000. The remaining working interest is owned by unaffiliated parties. There are currently 40 producing wells on this lease. We believe this property can support a number of additional wells, six of which are included in our estimate of PUD. This lease consists of approximately 2,240 acres and is held by production.

North Benson Queen Unit Eddy County, New Mexico. In October 2003 we acquired a 100% working interest and a 78.15% net revenue interest in this lease, which currently has 22 producing wells. This lease was acquired from United Resources, L.P., an unaffiliated company, for a cash payment of $500,000. The lease covers approximately 1,800 acres, and we believe this property can support a number of additional wells, 23 of which are included in our estimate of PUD. This lease is held by production.

The North Benson Queen Unit Waterflood will require additional volumes of water to support the waterflood expansion. A sufficient and economical source of water has been identified and contracted for. A water line of approximately four miles in length will be constructed across Bureau of Land Management lands to transport the water to the North Benson Queen Unit. Permit applications have been submitted to the Bureau of Land Management and we are awaiting final approval. The construction of the water line should require approximately thirty days at a cost of $250,000. The development of the North Benson Queen Unit waterflood is scheduled for 2006 at estimated costs of $4,800,000.

Significant Texas Operations

Fuhrman-Mascho leases Andrews County, Texas. In December 2004 we acquired a 100% working interest and a 75% net revenue interest in these leases from four entities; Paul D. Friemel & Assoc, Inc., Compostella Oil Company, Redco Oil & Gas Inc. and Terry N. Stevens, Inc., all unaffiliated companies. The purchase price, including acquisition costs, was $10,966,495 and consisted of $9,667,381 of cash paid to the sellers, $44,421 in cash acquisition costs, 179,658 shares of the Company s common stock, valued at $1,260,091, or $7.00 per share, and the issuance of put and call options with a net value of $24,602. These leases cover approximately 11,300 acres. We believe this property can support a number of additional wells, 147 of which are included in our estimate of PUD. These leases are held by production.

Y6 Lease Fisher County, Texas. We acquired a 100% working interest and an 80% net revenue interest in this lease in June 2001. This lease was acquired from Durango Operating Company, Inc. an unaffiliated company, for a cash payment of $750,000. There are currently 12 producing wells on this lease. A portion of this property has been waterflooded, and when we begin our future development operations on this property, we plan to waterflood the remaining acreage. A waterflood operation is a method of secondary recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells. This potential waterflood project (and the estimated $1,050,000 cost thereof) is included as PUD in our reserve report. This lease consists of approximately 1,697 acres and is held by production.

West San Andres Unit Yoakum County, Texas. In October 2003 we acquired a 100% working interest and a 79.60% net revenue interest in this lease from Permian Resources, Inc. an unaffiliated company, for a cash payment of $500,000. The lease covers approximately 1,200 acres, and currently has 12 producing wells. We believe this property can support a number of additional wells, four of which are included in our estimate of PUD. This lease is held by production.

Dodson Lease Montague County, Texas. We purchased a 100% working interest and an 81.25% net revenue interest in this lease in June 2002. This lease was acquired from Nocona minerals Partnership, an unaffiliated company, for a cash payment of $200,000. There are currently three producing wells and nine other wells on this approximately 570 acre lease, all of which is held by production.

Significant Oklahoma Operations

Ona Morrow Sand Unit Cimarron and Texas Counties, Oklahoma. We own a 100% working interest and an 81.32% net revenue interest in this lease which has been producing since our acquisition in July 2002. This lease was acquired from Bass Petroleum, Inc., an unaffiliated company, for a cash payment of $735,000. This lease has approximately 2,120 acres and 11 producing wells. We believe this property could support a number of additional wells, to of which are included in our estimate of our PUD. This lease is held by production.

Eva South Morrow Sand Unit Texas County, Oklahoma. We own a 100% working interest and an 85.41% net revenue interest in this lease which was also acquired in July 2002. This lease was acquired from Ensign Operating Company, an unaffiliated company, for a cash payment of $827,500. The lease consists of approximately 489 acres and has seven producing wells. We believe this property could support a number of additional wells, two of which have been included in our estimate of our PUD. This lease is held by production.

Midwell, Appleby, Smaltz and Hanes Leases Cimarron County, Oklahoma. We own 100% of the working interest and an 80% net revenue interest in these four leases acquired in September 2002. All have been producing leases since the date of our acquisition. The Midwell Appleby and Smaltz leases consist of approximately 1,640 acres with six producing wells, and we believe there are up to three additional drilling locations on these leases. The Hanes lease contains approximately 640 acres and two producing wells. We believe this property could support a number of additional wells, three of which are included in our estimate of PUD. All of these leases are held by production.

Roy Hanes Lease Texas County, Oklahoma. We own a 24.5% working interest and a 21.44% net revenue interest in this lease, which is a property operated by XTO Energy, Inc, an unaffiliated company, who also owns the remaining working interest. The interest in this lease was acquired at the same time we acquired our interests in the Midwell, Appleby, Smaltz and Hanes leases, and there has been production on this lease since that time. This lease consists of approximately 640 acres, and is currently held by production.

The Midwell, Appleby, Smaltz, Hanes and Roy Hanes leases were acquired from Burk Royalty Co., Ltd., R.A. Kimball Property Co., Ltd. and Kimball Family Resources, Ltd., all unaffiliated companies. The cost of these leases was $550,179, with $100,000 paid in cash and the balance paid through our issuance of 99,885 shares of our common stock valued at $4.00 per share (the then current market value), and the issuance of put and call options with a net value to the sellers of $50,639.

Significant Kansas Operations

Koehn/Rexford Unit Haskell & Gray County, Kansas. This lease consists of approximately 640 acres. After entering into a farmout agreement with Bird Creek Resources, Inc., an unaffiliated company, we drilled and completed an initial gas well on this lease. Under the terms of this agreement, we agreed to drill one well and could drill additional wells on the property. In exchange for each well drilled, we will be assigned 100% of the working interest (80% of the net revenue interest) in the well and related oil and gas until payout of all costs of drilling, equipping and operating the well. After payout, our working interest in the wells and related oil and gas will decrease to 75% (60% of the net revenue interest).

In 2002, we successfully drilled one well at a cost of approximately $153,000 to drill, complete and connect to the pipeline and thus will have reached payout when we recover this amount from production. After payout, Bird Creek Resources, Inc. will own the remaining 25% working interest.

On March 20, 2002, we entered into a joint venture agreement with Petro Consultants, Inc., to drill and operate the well on the above-mentioned property. Under the terms of the agreement, Petro purchased 27% of the working interest in the well for $88,200. On May 20, 2002, after the well was successfully drilled, we issued 70,000 shares of common stock (valued at $1.26 per share) to Petro to repurchase the 27% working interest in the well.

In February 2004, we successfully drilled one additional well on this acreage at a cost of approximately $159,000 to drill, complete and connect to the pipeline and thus will have reached payout when we recover this amount from production. After payout, Bird Creek Resources, Inc. will own the remaining 25% working interest.

In November 2004, we completed the installation of a pipeline from our Koehn lease to a gatherer/purchased pipeline. Total cost on installation of the pipeline was approximately $144,000. The installation of this pipeline was necessary to be able to begin producing from our wells in that area. Production started on December 11, 2004.

Schmidt Unit Gray County, Kansas. During 2004 we leased an additional 640 acres offsetting our Koehn/Rexford Unit for a total of approximately $8,582. In November 2004, we successfully drilled one well on this acreage at a cost of approximately $183,520 to drill, complete and connect to the pipeline. We began producing from this well on December 23, 2004.

Beals Prospect Comanche County, Kansas. In July 2003 we acquired a 100% working interest and an 80.5% net revenue interest in this lease, consisting of 1,560 acres. This lease was acquired from Bengalia Land and Cattle Company, an unaffiliated party, for a cash payment of $60,000. These leases will expire in April 2006; however, the Company is in the process of extending the leases an additional year.

Syracuse Prospect Hamilton County, Kansas. During 2005 we leased 15,680 acres for a total of approximately $433,134. These leases provide us a 100% working interest and an 81% net revenue interest. During 2005, we drilled two wells, both of which are still under analysis and are being considered for completion. Additionally, we sold 41.25% of the working interest in these wells, for total proceeds of $340,000.

Rocky Prospect Comanche County, Kansas. During 2005 we leased 4,160 acres for a total of approximately $141,412. These leases provide us a 100% working interest and an 80% net revenue interest. During 2005, we drilled two wells on this property. One well was completed and put into production in December 2005. We sold a 41.25% working interest in this well for total proceeds of $170,000. The second well was drilled successfully but was pending completion at December 31, 2005. We sold a 50% working interest in this well for proceeds of $215,000, plus a commitment to pay a determined amount if the well was successful, dependant upon what zone or zones the well was to be completed in.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2005 by region (net acreage is our percentage ownership of gross acreage). Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		**Undeveloped Acreage**		**Total Acreage**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
New Mexico	4,960	3,294	--	--	4,960	3,294
Texas	15,687	11,941	--	--	15,687	11,941
Oklahoma	5,529	4,122	--	--	5,529	4,122
Kansas	3,520	2,816	20,600	16,645	24,120	19,461
Total	26,696	22,174	20,600	16,645	50,296	38,819

Production History

The following table presents the historical information about our produced natural gas and oil volumes.

	Year Ended December 31,		
	2003	**2004**	**2005**
Oil production (Bbls)	117,646	195,166	441,995
Natural gas production (Mcf)	67,329	169,002	398,611
Total production (Boe)	128,868	223,333	508,430
Daily production (Boe/d)	353	612	1,393
Average sales price:			
Oil (per Bbl)	$ 29.06	$ 39.25	$ 52.41
Natural gas (per Mcf)	3.67	4.86	6.72
Total (per Boe)	28.44	37.98	50.83
Average production cost (per Boe)	$ 8.92	$ 8.85	$ 7.54

The average oil sales price amounts above are calculated by dividing revenue from oil sales by the volume of oil sold, in Bbl. The average gas sales price amounts above are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The total average sales price amounts are calculated by dividing total revenues by total volume sold, in Boe. The average production costs above are calculated by dividing production costs by total production in Boe.

Productive Wells

The following table presents our ownership at December 31, 2005, in productive oil and natural gas wells by region (a net well is our percentage ownership of a gross well).

	Oil Wells		Gas wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
New Mexico	90	59	-	-	90	59
Texas	223	169	-	-	223	169
Oklahoma	26	21	-	-	26	21
Kansas	-	-	7	6	7	6
Total	339	249	7	6	346	254

Drilling Activity

During 2005 we completed the drilling of forty-six wells. Thirty-six wells were drilled on our Fuhrman Mascho properties in Andrews County, Texas. Six of the wells were drilled in Kansas, two in Gray County, Kansas, offsetting our existing wells there and four in Hamilton and Greeley County, Kansas on acreage acquired during 2005. The four wells in Hamilton and Greeley Counties were exploratory wells. Three wells were drilled on our East Hobbs property in Lea County, New Mexico. One well was drilled on our Eva South property in Texas County, Oklahoma.

Cost Information

We conduct our oil and natural gas activities entirely in the United States. As noted previously in the table appearing under Production History , our average production costs, per Boe, were $8.92 in 2003, $8.85 in 2004 and $7.54 in 2005. These amounts are calculated by dividing our total production costs by our total volume sold, in Boe.

Costs incurred for property acquisition, exploration and development activities during the years ended December 31, 2003, 2004 and 2005 are shown below.

	For the Years Ended December 31,		
	2003	**2004**	**2005 (1)**
Acquisition of proved properties	$ 2,692,039	$ 21,706,166	$ 1,406,588
Acquisition of unproved properties	147,000	43,082	(160,454)
Exploration costs	326,410	216,805	464,656
Development costs	849,864	4,027,754	32,557,989
Total Costs Incurred	$ 4,015,313	$ 25,993,807	$ 34,268,779

(1) The amount shown for 2005 for acquisition of unproved properties is net of proceeds received for partial working interests sold in wells drilled in Kansas.

Reserve Quantity Information

Our estimates of proved reserves and related valuations were based on reports prepared by Lee Keeling and Associates, Inc., independent petroleum and geological engineers, in accordance with the provisions of SFAS 69, Disclosures About Oil and Gas Producing Activities. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

Our oil and natural gas reserves are attributable solely to properties within the United States. A summary of the changes in quantities of proved (developed and undeveloped) oil and natural gas reserves is shown below.

	Oil (Bbls)	Natural Gas (Mcf)
Balance, December 31, 2002	4,113,936	3,187,757
Purchase of minerals in place	3,175,357	570,924
Extensions and discoveries	18,066	229,626
Production	(117,646)	(67,329)
Revisions of estimates	(139,546)	(512,224)
Balance, December 31, 2003	7,050,167	3,408,754
Purchase of minerals in place	8,764,087	6,431,437
Extensions and discoveries	-	640,000
Production	(195,167)	(169,002)
Revisions of estimates	3,931,577	(311,648)
Balance, December 31, 2004	19,550,664	9,999,541
Purchase of minerals in place	882,460	377,179
Extensions and discoveries	2,546,477	19,188,896
Production	(441,995)	(398,611)
Revisions of estimates	2,329,583	2,815,074
Balance, December 31, 2005	24,867,189	31,982,079

Our proved oil and natural gas reserves are shown below.

	For the Years Ended December 31,		
	2003	2004	2005
Oil (Bbls)			
Developed	1,580,521	4,721,293	7,885,115
Undeveloped	5,469,646	14,829,371	16,982,074
Total	7,050,167	19,550,664	24,867,189
Natural Gas (Mcf)			
Developed	1,612,738	4,615,265	22,480,279
Undeveloped	1,796,016	5,384,276	9,501,800
Total	3,408,754	9,999,541	31,982,079
Total (Boe)			
Developed	1,849,311	5,490,504	11,631,829
Undeveloped	5,768,972	15,726,750	18,565,707
Total	7,618,283	21,217,254	30,197,536

Standardized Measure of Discounted Future Net Cash Flows

Our standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and changes in the standardized measure as described below were prepared in accordance with the provisions of SFAS 69. Future cash inflows were computed by applying year-end prices to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in producing and developing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10 percent annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and natural gas properties.

The standardized measure of discounted future net cash flows relating to the proved oil and natural gas reserves are shown below.

December 31,	2005	2004	2003
Future cash flows	$ 1,629,948,750	$ 814,346,791	$ 218,026,254
Future production costs	(281,685,991)	(171,518,828)	(64,157,199)
Future development costs	(95,765,594)	(61,975,106)	(13,609,384)
Future income taxes	(423,161,523)	(187,392,403)	(45,778,941)
Future net cash flows	829,335,642	393,460,454	94,480,730
10% annual discount for estimated timing of cash flows	(383,735,076)	(188,219,704)	(49,474,633)
Standardized Measure of Discounted Cash Flows	$ 445,600,566	$ 205,240,750	$ 45,006,097

The changes in the standardized measure of discounted future net cash flows relating to the proved oil and natural gas reserves are shown below.

For the Years Ended December 31,	2005	2004	2003
Beginning of the year	$ 205,240,750	$ 45,006,097	$ 27,997,824
Purchase of minerals in place	33,405,120	142,824,938	21,333,720
Extensions, discoveries and improved recovery, less related costs	5,962,820	347,652	691,469
Development costs incurred during the year	189,832,736	5,387,638	320,102
Sales of oil and gas produced, net of production costs	(21,991,034)	(5,876,333)	(2,302,405)
Accretion of discount	28,467,073	4,882,064	3,012,793
Net changes in price and production costs	191,917,618	74,777,221	8,222,075
Net change in estimated future development costs	(36,307,702)	(3,187,159)	39,219
Revision of previous quantity estimates	87,175,031	42,149,044	(53,098)
Revision of estimated timing of cash flows	(111,387,288)	(27,509,967)	(5,468,732)
Net change in income taxes	(126,714,558)	(73,560,445)	(8,786,870)
End of the Year	$ 445,600,566	$ 205,240,750	$ 45,006,097

Management s Business Strategy Related to Properties

Our goal is to increase stockholder value by investing in oil and gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing acquisitions of additional properties. Specifically, we have focused, and plan to continue to focus, on the following:

Developing and Exploiting Existing Properties. We believe that there is significant value to be created by drilling the identified undeveloped opportunities on our properties. We own interests in a total of 29,696 gross (22,174 net) developed acres and operate essentially all of the net pre-tax PV10 value of our proved undeveloped reserves. In addition, as of December 31, 2005, we owned interests in approximately 20,600 gross undeveloped acres (16,645 net). We believe that our current and future cash flow will enable us to undertake the exploitation of our properties through additional drilling activities. Our expected capital budget for development of existing properties in 2006 is approximately $61 million.

Pursuing Profitable Acquisitions. We have historically pursued acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management and engineering professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. While our emphasis in 2006 and beyond is anticipated to focus on the further development of our existing properties, we will continue to look for properties with both existing cash flow from production and future development potential.

Controlling Costs through Efficient Operation of Existing Properties. We operate essentially 100% of the pre-tax PV10 value of our total proved reserves, which we believe enables us to better manage expenses, capital allocation and the decision-making processes related to our exploitation and exploration activities. For the year ended December 31, 2005, our oil and gas production costs per Boe averaged $7.54 and general and administrative costs averaged $2.69 per Boe produced.

Other Properties and Commitments

We currently lease our principal executive offices in Tulsa, Oklahoma. At December 31, 2005, the lease was for approximately 3,224 square feet of office space, at an annual rental of $30,000. This lease is set to expire at December 31, 2006. The current facilities are believed adequate for our current operations.

Item 3: <u>Legal Proceedings</u>

In the ordinary course of business, we may be, from time to time, a claimant or a defendant in various legal proceedings. We do not presently have any litigation pending or threatened.

Item 4: <u>Submission of Matters to a Vote of Security Holders</u>

Our annual shareholders meeting was held on December 15, 2005. The shareholder s re-elected Messrs. Stanley M. McCabe, Lloyd T. Rochford, Charles M. Crawford, Chris V. Kemendo, Jr. and Clayton E. Woodrum as Directors with terms ending in 2006. The shareholders further approved an amendment to the Company s executive stock option plan to increase the number of shares of Common Stock that may be granted under the plan from 1,500,000 to 2,000,000. Additionally, due to the fact that under existing rules of the American Stock Exchange, essentially any issuance of common stock to employees or consultants must be approved by the stockholders, at the meeting a proposal was presented to allow for the issuance of up to 50,000 shares of common stock to employees or consultants as compensation for services. This matter was voted on pursuant to the discretionary authority granted under the proxies solicited for the annual meeting. The following reflects the votes cast for each matter voted on at the annual meeting:

	Votes for	Votes against	Abstain
Lloyd T. Rochford	10,747,316	-	629,505
Stanley M. McCabe	11,194,710	-	182,111
Charles M. Crawford	11,278,076	-	98,745
Chris V. Kemendo, Jr.	10,776,131	-	600,690
Clayton E. Woodrum	11,210,085	-	166,536
Amendment to option plan	10,470,309	872,422	34,090
Adoption of Stock Compensation Plan	10,470,309	872,422	34,090

PART II

Item 5: **Market for Registrant s Common Stock, Related Stockholder Matters and Issuer Purchases of Equity Securities**

Market for our Common Stock

Since April 15, 2003, our common stock has been traded on the American Stock Exchange, under the symbol ARD . Prior to that time, our common stock traded on the OTC Bulletin Board. The following table shows the high and low sales prices for each quarter since listing on the American Stock Exchange, and the high and low bid prices prior to such time, during the last three years.

Period	High Sale or Bid	Low Sale or Bid
1st Quarter 2003	$ 4.35	$ 4.25
2nd Quarter 2003	5.99	4.35
3rd Quarter 2003	5.82	5.45
4th Quarter 2003	6.10	5.40
1st Quarter 2004	$ 7.08	$ 5.85
2nd Quarter 2004	9.65	6.98
3rd Quarter 2004	7.46	5.98
4th Quarter 2004	8.79	6.80
1st Quarter 2005	$ 15.05	$ 7.89
2nd Quarter 2005	13.95	9.20
3rd Quarter 2005	26.20	11.35
4th Quarter 2005	29.40	19.46
1st Quarter 2006 (through February 28, 2006)	$ 36.99	$ 26.90

Record Holders

As of February 28, 2006, there are approximately 4,167 holders of record of our common stock. Approximately 17%, or 2,230,200 shares of the 13,226,702 shares issued and outstanding as of such date are held by management or affiliated parties.

Dividend Policy

We have not paid any dividends on our common stock during the last three years, and we do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, our credit facility prohibits us from paying dividends.

Securities Authorized for Issuance Under Equity Compensation Plans

In March 2003, our board of directors adopted an executive stock option plan which was subsequently approved by our shareholders at our annual meeting in July 2003, and which was amended by our shareholders at our annual meeting in 2004 and in 2005. Information regarding this plan and the options that have been granted under this plan may be found in this Annual Report under Part III, Items 10 and 11.

Recent Sales of Unregistered Securities

During the three months ended December 31, 2005, we issued 37,250 shares of our common stock upon the exercise of previously issued warrants at either $3.00 per share or $9.00 per share. These shares were issued in a transaction not involving a public offering and were issued in reliance upon the exemption from registration provided by Section 4(2) of the Securities Act of 1933. The persons to whom the shares were issued had access to full information concerning us and represented that he acquired the shares for his own account and not for the purpose of distribution. The certificates for the shares contain a restrictive legend advising that the shares may not be offered for sale, sold or otherwise transferred without having first been registered under the 1933 Act or pursuant to an exemption from registration under the 1933 Act. There was no underwriter involved in these transactions.

During the three months ended December 31, 2005, we issued 29,126 warrants to purchase our common stock at an exercise price of $10.30 per share. These warrants were issued in a transaction not involving a public offering and were issued in reliance upon the exemption from registration provided by Section 4(2) of the Securities Act of 1933. The persons to whom the shares were issued had access to full information concerning us and represented that he acquired the shares for his own account and not for the purpose of distribution. The certificates for the shares contain a restrictive legend advising that the shares may not be offered for sale, sold or otherwise transferred without having first been registered under the 1933 Act or pursuant to an exemption from registration under the 1933 Act. There was no underwriter involved in these transactions.

Issuer Repurchases

We did not make any repurchases of our equity securities during the quarter ending December 31, 2005.

Item 6: **Selected Financial Data**

The selected consolidated financial information set forth below is derived from our consolidated balance sheets and statements of operations as of and for the years ended December 31, 2005, 2004, 2003, 2002 and 2001. The data set forth below should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the consolidated financial statements and related notes thereto included in this Annual Report.

	For the Year Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Statement of Operations Data:					
Revenues	$ 25,843,077	$ 8,482,130	$ 3,665,477	$ 1,657,037	$ 311,733
Cost of revenues	5,772,225	2,605,538	1,418,699	712,027	121,724
Depreciation, depletion and amortization	2,781,504	1,011,602	360,282	127,847	44,148
Accretion	102,585	53,729	322,212	-	-
General and administrative	1,365,590	874,850	778,774	248,018	119,696
Net income	9,460,683	2,451,652	670,143	402,694	18,165
Preferred stock dividends	-	-	-	798,018	63,092
Income (Loss) attributable to common shareholders	9,460,683	2,451,652	670,143	(395,324)	(44,927)
Basic income (loss) per common share	$ 0.85	$ 0.31	$ 0.10	$ (0.09)	$ (0.01)
Diluted income (loss) per common share	0.75	0.28	0.09	(0.09)	(0.01)

	As of December 31,				
	2005	2004	2003	2002	2001
Balance Sheet Data:					
Current assets	$ 7,673,860	$ 2,498,423	$ 1,519,755	$ 1,224,979	$ 479,203
Oil and gas properties subject to amortization	69,770,685	34,457,137	8,463,400	4,884,804	1,645,819
Total assets	74,421,907	36,377,524	9,973,256	6,050,493	2,137,689
Total current liabilities	6,260,210	1,840,665	250,867	287,859	99,735
Total long-term liabilities	9,432,942	13,735,016	1,582,116	637,797	-
Total Stockholders Equity	58,728,755	20,801,843	8,140,273	5,124,837	2,037,954

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

Introduction

The following discussion and analysis should be read in conjunction with our accompanying financial statements and the notes to those financial statements included elsewhere in this Annual Report. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this Annual Report.

Overview

We are engaged in oil and natural gas acquisition, exploration and exploitation activities in the states of Oklahoma, Texas, New Mexico and Kansas. Over the last four years, we have emphasized the acquisition of properties that provided current production and upside potential through further development.

We have increased our reserves significantly by investing approximately $34.3 million in acquisitions and enhancements in 2005, following total capital expenditures of approximately $26 million in 2004 and approximately $4 million in 2003.

Our capital budget for 2006 is approximately $61 million for development of existing properties. We also intend to continue seeking acquisition opportunities which compliment our current portfolio. We intend to fund our development activity primarily through use of cash flow from operations and cash on hand, while potential drawings on our credit facility and proceeds from future equity transactions would also be available for development projects or future acquisitions.

Our business plan has involved increasing our base of proven reserves until we have acquired a sufficient core to enable us to utilize cash from existing production to fund further development activities. When we originated our business plan we believed this would allow us to lessen our risks, including risks associated with borrowing funds to undertake exploration activities at an earlier time. As we have now increased our base of proven properties, and as oil and natural gas prices have recently significantly risen, we have initiated our development activities.

While our focus has shifted to include more development activity, we plan to continue our strategy of acquiring producing properties with additional development, exploitation and exploration potential. Our focus has been on acquiring operated properties (i.e. properties with respect to which we serve as the operator on behalf of all joint interest owners) so that we can better control the timing and implementation of capital spending. In addition, our willingness to acquire non-operated properties in new geographic regions may provide us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

In a worst case scenario, future drilling operations could be largely unsuccessful, oil and gas prices could sharply decline and/or other factors beyond our control could cause us to greatly modify or substantially curtail our development plans, which could negatively impact our earnings, cash flow and most likely the trading price of our securities, as well as the acceleration of debt repayment and a reduction in our borrowing base under our credit facilities.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	For the Years Ended December 31,		
	2003	**2004**	**2005**
Net production:			
Oil (Bbls)	117,646	195,166	441,995
Natural gas (Mcf)	67,329	169,002	398,611
Net sales:			
Oil	$ 3,418,480	$ 7,661,006	$ 23,165,109
Natural gas	246,997	821,124	2,677,968
Average sales price:			
Oil (per Bbl)	$ 29.06	$ 39.25	$ 52.41
Natural gas (per Mcf)	3.67	4.86	6.72
Production costs and expenses			
Oil and gas production costs	$ 1,149,136	$ 1,975,835	$ 3,832,486
Production taxes	269,563	629,703	1,939,739
Depreciation, depletion and amortization expense	360,282	1,011,602	2,781,504
Accretion expense	32,212	53,729	102,585
General and administrative expenses	778,774	874,850	1,365,590

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $17.36 million to $25.84 million in 2005. Oil sales increased $15.50 million and natural gas sales increased $1.86 million. The oil sales increase was caused by a sales volume increase of 246,829 barrels in 2005, and a 34% increase in the average realized per barrel oil price from $39.25 in 2004 to $52.41 in 2005. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. The natural gas sales increase was caused by a sales volume increase of 229,609 Mcf in 2005 and a 38% increase in the average realized natural gas price per Mcf from $4.86 in 2003 to $6.72 in 2004. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The volume increase for crude oil and natural gas primarily resulted from acquisitions made in 2004 and development of our existing properties in 2005.

Oil and gas production costs. Our aggregate oil and gas production costs increased from $1,975,835 in 2004 to $3,832,486, although such expenses on a Boe basis declined from $8.85 in 2004 to $7.54 in 2005. These per Boe amounts are calculated by dividing our total production costs by our total volume sold, in Boe. This aggregate increase was the result of having the properties acquired in 2004 in our operations for a full year in 2005, and the drilling of new wells in 2005 and cost increases. The decline on a per Boe basis is attributable to consolidation of resources available due to our growth.

Oil and gas production taxes. Oil and gas production taxes as a percentage of oil and natural gas sales were 7.42% during 2004 and increased to 7.51% in 2005. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased by $1,769,902 to $2,781,504 in 2005. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $4.53 per Boe during 2004 to $5.47 per Boe during 2005. These per Boe amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total volume sold, in Boe. The increased depreciation, depletion and amortization was the result of increased sales volume and an increase in estimated future development costs.

General and administrative expenses. General and administrative expenses increased by $490,740 to $1,365,590 during 2005. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer our growth.

Other Financing expense. Other financing expense was $597,773 in 2005, compared to $0 in 2004. The increase is a result of the offering to which the financing expenses relate that occurred in 2005.

Interest expense. Interest expense increased $73,688 to $229,624 in 2005. The increase was due to higher amounts of debt being outstanding during periods of the year in 2005.

Income tax expense. Our effective tax rate was 37% during 2005 and 37% during 2004.

Net income. Net income increased from $2,451,652 for 2004 to $9,460,683 for 2005. The primary reasons for this increase include higher crude oil and natural gas prices between periods and an increase in volumes sold, partially offset by higher oil and gas production costs, oil and gas production taxes and general and administrative expenses due to our growth.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $4.82 million to $8.48 million in 2004. Oil sales increased $4.24 million and natural gas sales increased $575,000. The oil sales increase was caused by a sales volume increase of 77,520 barrels in 2004, and a 35% increase in the average realized per barrel oil price from $29.06 in 2003 to $39.25 in 2004. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. The natural gas sales increase was caused by a sales volume increase of 101,673 Mcf in 2004 and a 32% increase in the average realized natural gas price per Mcf from $3.67 in 2003 to $4.86 in 2004. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The volume increase for crude oil and natural gas primarily resulted from $26 million of capital expenditures during 2004, of which approximately $21 million were related to our acquisition of the East Hobbs and Fuhrman Mascho properties.

Oil and gas production costs. Our aggregate oil and gas production costs increased from $1,149,136 in 2003 to $1,975,835 2004, although such expenses on a Boe basis declined slightly from $8.92 in 2003 to $8.85 in 2004. These per Boe amounts are calculated by dividing our total production costs by our total volume sold, in Boe. This aggregate increase was the result of having the properties acquired in 2003 in our operations for a full year in 2004; acquiring new properties and accounting for them for a portion of the year in 2004 and cost increases. The decline on a per Boe basis is attributable to consolidation of resources available due to our growth.

Oil and gas production taxes. Oil and gas production taxes as a percentage of oil and natural gas sales were 7% during 2003 and remained steady at 7% in 2004. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased by $651,320 to $1,011,602 in 2004. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $2.79 per Boe during 2003 to $4.53 per Boe during 2004. These per Boe amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total volume sold, in Boe. The increased depreciation, depletion and amortization was the result of increased sales volume and an increase in estimated future development costs.

General and administrative expenses. General and administrative expenses increased by $96,076 to $874,850 during 2004. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer our growth, legal fees of $31,150, annual listing fees of $18,700, $16,095 in fees paid to Lee Keeling for 2003 reserve reports, fees related to obtaining our credit facility and letters of credit and directors fees.

Interest expense. Interest expense increased $117,138 to $155,936 in 2004. The increase was due to higher amounts of debt being outstanding during periods of the year in 2004.

Income tax expense. Our effective tax rate was 37% during 2004 and 37% during 2003.

Cumulative change in accounting principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 8.08%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted abandonment liability of $236,718, increased proved property cost by $217,878, and recognized a one-time cumulative effect charge of $11,813 (net of a related tax effect of $7,027). The effect of adopting this accounting principle was a $24,873 after tax decrease in net income during 2003.

Net income. Net income increased from $670,143 for 2003 to $2,451,652 for 2004. The primary reasons for this increase include higher crude oil and natural gas prices between periods and an increase in volumes sold, partially offset by higher oil and gas production costs, oil and gas production taxes and general and administrative expenses due to our growth.

Liquidity and Capital Resources

Historical Financing. We have historically funded our operations through loans from our executive officers, our initial public offering of stock in 2001, private equity offerings of our stock and warrants and our secondary offering of common stock and warrants which we closed in August 2004.

Credit Facility. On April 14, 2004, we established a $15,000,000 credit facility with our principal lenders with an $8,500,000 initial borrowing base. In April 2005, we entered into an agreement that increased the facility to $50,000,000, with an increased borrowing base of $35,000,000. Any increases in the borrowing base are subject to written consent by the financial institution. The interest rate is a floating rate equal to the 30, 60 or 90 day LIBOR rate plus 2.25%, currently 7.11% per annum, and is payable monthly. Amounts borrowed under the revolving credit facility are due on April 30, 2008. The revolving credit facility is secured by our principal mineral interests. In order to obtain the revolving credit facility, loans from two officers were subordinated to the position of the bank. We are required under the terms of the credit facility to maintain a tangible net worth of $12,000,000, maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense and maintain a current asset to current liability ratio of 1-to-1. At December 31, 2005, no amounts were outstanding under this credit facility, though $299,029 is reserved under the revolving credit facility as collateral for standby letters of credit issued to various states.

Cash Flows. Our primary sources of cash have been cash flows from operations and equity offerings. During the three years ended December 31, 2005, we generated $28,467,736 from operating activities, financed $37,763,518 through proceeds from the sale of stock and warrants, and $400,000 from debt obligations owed to two officers, for a total of $66,631,254. We primarily used this cash generation to fund our capital expenditures and development aggregating $44,745,430 over the three years. At December 31, 2005, we had cash on hand of $4,317,114 and working capital of $1,083,664, compared to December 31, 2004 when our cash was $1,253,969 and working capital of $657,758.

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for 2006 are approximately $61,000,000 for development of our current properties. We expect to fund these expenditures as well as any future property acquisitions from cash on hand, internally generated cash flow during the year 2006, proceeds from future equity transactions and from borrowings under our credit facility, if required. The level of capital expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among others.

Schedule of Contractual Obligations. The following table summarizes our future estimated principal and minimum debt and lease payments for periods subsequent to December 31, 2005.

Year	**Long-Term Debt**	**Lease Obligation**	**Total Cash Obligation**
2006	$ -	$ 30,000	$ 30,000
2007	400,000	-	$ 400,000
2008	-	-	$ -
Total	$ 400,000	$ 30,000	$ 430,000

Off-Balance Sheet Financing Arrangements

As of December 31, 2005 we had no off-balance sheet financing arrangements.

New Accounting Policies

Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to us, this statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 8.08%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted abandonment liability of $236,718, increased property and equipment cost by $217,878 and recognized a one-time cumulative effect charge of $11,813 (net of a deferred tax benefit of $7,027).

The adoption of SFAS No. 143 also affected the depreciation, depletion and amortization on an on-going basis. The additionally capitalized amount for the discounted abandonment liability increases the base amount used in calculating depletion. This effect was an increase in depreciation, depletion and amortization for the years ended December 31, 2003, 2004 and 2005 of $7,459, $10,798 and $21,619, respectively. The adoption of SFAS No. 143 also impacted the way the ceiling test is calculated under the full cost accounting method used by the Company, in that an estimation of future abandonment costs are now excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation. However, these costs are now part of the base amount, so while the way the calculation is performed has changed, the end result remains the same. There were no other impacts of the adoption of SFAS No. 143.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities*. This interpretation establishes the requirement for a primary beneficiary to consolidate certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. We do not have an interest in a variable interest entity and the adoption of the statement did not have an impact on our financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement was effective for us in July 2003. The statement requires financial instruments to be classified as liabilities if the financial instruments are issued in the form of shares that are mandatorily redeemable or embody an obligation to repurchase equity shares. We issued a put option in exchange for oil and gas property interests in December 2004. The put option was originally classified as a liability; therefore, the adoption of the statement did not have an impact on our financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our financial statements. The preparation of these statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. Our significant accounting policies are detailed in Note 1 to our financial statements included in this Annual Report. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

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

Full Cost Method of Accounting. We account for our oil and natural gas operations using the full cost method of accounting. Under this method, all costs associated with property acquisition, exploration and development of oil and gas reserves are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and cost of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. All of our properties are located within the continental United States.

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

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

Our proved reserve information included in this Annual Report is based on estimates prepared by Lee Keeling and Associates, Inc., independent petroleum engineers. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional properties are acquired. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made.

All capitalized costs of oil and gas properties, including estimated future costs to develop proved reserves and estimated future costs of site restoration, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent engineers. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined.

Impairment of Oil and Natural Gas Properties. We review the value of our oil and natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. We provide for impairments on undeveloped property when we determine that the property will not be developed or a permanent impairment in value has occurred. Impairments of proved producing properties are calculated by comparing future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost at the end of each period. If the net capitalized cost exceeds net future cash flows, the cost of the property is written down to fair value, which is determined using net discounted future cash flows from the producing property. Different pricing assumptions or discount rates could result in a different calculated impairment. We have never recorded any property impairments.

Income Taxes. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. Deferred income taxes are provided for the difference between the tax basis of assets and liabilities and the carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to actual in the period we file our tax returns.

Effects of Inflation and Pricing

As in 2004, we did experience continued increases in cost during 2005 due to increased demand for oil field products and services. The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs, and this proved to be the case in 2005 as oil and gas prices rose significantly. Costs for oilfield services and materials increased during 2005 due to higher demand as a result of the higher oil and gas prices. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. We anticipate the increased business costs will continue while the commodity prices for oil and natural gas, and the demand for services related to production and exploration, both remain high (from an historical context) in the near term.

Item 7A: **Quantitative and Qualitative Disclosure About Market Risk**

Commodity Price Risk

We have not historically entered into derivative contracts to manage our exposure to oil and natural gas price volatility. Normal hedging arrangements have the effect of locking in for specified periods the prices we would receive for the volumes and commodity to which the hedge relates. Consequently, while hedges are designed to decrease exposure to price decreases, they also have the effect of limiting the benefit of price increases.

Interest Rate Risk

Our current credit facility has a floating interest rate. Therefore, as a result of our draws on this credit facility, interest rate changes will impact future results of operations and cash flows.

Item 8: **Financial Statements and Supplementary Data**

The financial statements and supplementary data required by this item are included at page 50.

Item 9: **Changes in and Disagreements with Accountants And Accounting and Financial Disclosure**

None.

Item 9A: **Controls and Procedures**

Evaluation of Disclosure Controls and Procedures.

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission. As of the end of the fiscal year ended December 31, 2005, our chief executive officer and chief financial officer evaluated the effectiveness of our disclosure controls and procedures. Based upon their evaluation of those controls and procedures, the chief executive officer and the principal financial officer of the Company concluded that as of the end of such period our disclosure controls and procedures are effective in alerting them to material information in a timely manner that is required to be included in the reports we file or submit under the Securities Exchange Act of 1934.

Management s Annual Report on Internal Control Over Financial Reporting.

Our management is responsible for establishing and maintaining adequate internal controls over financial reporting. Our internal control system was designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

In making our assessment of internal control over financial reporting, our management used the criteria issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework*. Based on our assessment, we believe that, as of December 31, 2005, our internal control over financial reporting is effective based on those criteria.

Hansen, Barnett & Maxwell, our independent registered public accounting firm, has issued an attestation report on management s assessment of Arena s internal control over financial reporting.

Date: March 15, 2006

/s/ Lloyd T. Rochford
Chief Executive Officer

/s/ William R. Broaddrick
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of Arena Resources, Inc.

We have audited management s assessment, included in the accompanying *Management s Annual Report on Internal Control Over Financial Reporting,* that Arena Resources, Inc. maintained effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Arena Resources, Inc. s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of the company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, management s assessment that Arena Resources, Inc. maintained effective internal control over financial reporting as of December 31, 2005 is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Arena Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Arena Resources, Inc. as of December 31, 2005 and 2004, and the related consolidated statements of operations, stockholders equity and cash flows for each of the three years in the period ended December 31, 2005 of Arena Resources, Inc. and our report dated March 14, 2006 expressed an unqualified opinion thereon.

HANSEN, BARNETT & MAXWELL

Salt Lake City, Utah
March 14, 2006

Changes in Internal Control Over Financial Reporting.

We made no change in our internal control over financial reporting during our fourth quarter of 2005 that has materially affected, or is reasonably likely to materially affect our internal control over financial reporting.

Item 9B: Other Information

None

PART III

Item 10: Directors and Executive Officers

Executive Officers and Directors

The following table sets forth information regarding our executive officers, certain other officers and directors as of December 31, 2005:

Name	Age	Position
Lloyd T. Rochford	59	President and Chief Executive Officer and Director
Stanley M. McCabe	73	Chairman of the Board of Directors, Secretary and Treasurer
William R. Broaddrick	28	Vice President and Chief Financial Officer
Charles M. Crawford	53	Director
Chris V. Kemendo, Jr.	84	Director
Clayton E. Woodrum	65	Director

Each of the directors identified above were elected for a term of one year (or until their successors are elected and qualified) at our annual meeting of shareholders in December 2005.

Messrs. Rochford, McCabe and Crawford have served as directors since our inception in August 2000. Mr. Kemendo was first elected to the Board of Directors in February 2003 and Mr. Woodrum was initially appointed in August 2003 by the Board of Directors to fill a vacancy created upon the resignation of a director.

The following biographies describe the business experience of our executive officers and directors:

Lloyd T. Rochford President, Chief Executive Officer and Director.

Mr. Rochford, 59, has been active as an individual consultant and entrepreneur in the oil and gas industry since 1973. In this capacity, he has primarily been engaged in the organization and funding of private oil and gas drilling and completion projects and ventures within the mid-continent region of the United States. In 1990 Mr. Rochford was co-founder, director and CEO of a public company known as Magnum Petroleum, Inc. (Magnum) which was listed on the New York Stock Exchange. Subsequently, Magnum acquired Hunter Resources, Inc. in August, 1995. Mr. Rochford served as Chairman of the Board of the combined companies from August, 1995 to June, 1997. From July, 1997 until he committed to participate in Arena Resources, Mr. Rochford had primarily devoted his time and efforts to individual oil and gas acquisition and development. In 1982, Mr. Rochford was co-founder of Dana Niguel Bank, a publicly held California bank operation and served as a director until 1994. Mr. Rochford attended various college level courses in business from 1967 to 1970 in California.

Stanley M. McCabe Chairman of the Board of Directors, Secretary and Treasurer.

Mr. McCabe, 73, served from 1979 to 1989, as Chairman and CEO of Stanton Energy, Inc., a Tulsa, Oklahoma natural resource company specializing in contract drilling and operation of oil and gas wells. In 1990, Mr. McCabe also became a co-founder and subsequently an officer and director of Magnum Petroleum, Inc., along with Mr. Rochford as previously discussed. Subsequently, Mr. McCabe served as a director of Magnum Hunter Resources, Inc., through December, 1996. From January, 1997, until he committed to participate in Arena Resources, Mr. McCabe had primarily devoted his time and efforts to individual oil and gas acquisition and development. Mr. McCabe attended college courses at the University of Maryland, primarily in business, in 1961 and 1962.

William R. Broaddrick Vice President and Chief Financial Officer.

Mr. Broaddrick, 28, was employed from 1997 to 2000 with Amoco Production Company, performing lease revenue accounting and state production tax regulatory reporting functions. During 2000, Mr. Broaddrick was employed by Duke Energy Field Services, LLC performing state production tax functions. In September 2001, Mr. Broaddrick joined us as chief accountant, and effective February 1, 2002, assumed responsibilities as Vice President and Chief Financial Officer.

Mr. Broaddrick received a Bachelor s Degree in Accounting from Langston University, through Oklahoma State University Tulsa, in 1999. Mr. Broaddrick is a Certified Public Accountant.

Charles M. Crawford Director

Mr. Crawford, 53, has for the past twenty-nine years served as an independent oil and gas exploration consultant to various private and public oil and gas companies within the United States. He has acted as a consultant to such firms as Texaco, Inc, Phillips Petroleum Company, Mid-Continent Energy Corp. as well as other regional and national companies primarily acting in the mid-continent area. Mr. Crawford received a Masters Degree in geology from Miami University of Ohio, in 1976. Mr. Crawford will serve the company on an as needed basis as an outside director.

Chris V. Kemendo, Jr. Director.

Mr. Kemendo, 84, has from 1989 to present acted as an independent financial business and accounting consultant to various clients. Mr. Kemendo has 56 years of accounting experience. Mr. Kemendo graduated from the University of Oklahoma and subsequently became a Certified Public Accountant. From 1947 to 1957, Mr. Kemendo was a manager of Arthur Young & Company, in charge of audit departments in Kansas City, Missouri, Wichita, Kansas and Caracas, Venezuela. From 1957 to 1961, Mr. Kemendo served as Controller and CFO for Rio Arriba Drilling Company. From 1961 to 1967, he was a partner of Fox & Company, Certified Public Accountants. From 1967 to 1973, he served as Executive Vice-President and CFO of LaBarge, Inc. From 1973 to 1979, Mr. Kemendo was a partner at Daniel and Howard, Inc. From 1979 to 1982, he again served as a partner at Fox & Company (now Grant Thornton, LLP). From 1982 to 1988, Mr. Kemendo was Executive Vice-President and Director at Fitzgerald, DeArman & Roberts, Inc.

Clayton E. Woodrum Director.

Mr. Woodrum, 65, is a Certified Public Accountant and has, from 1984 to present, been a principal shareholder in the accounting firm of Woodrum, Kemendo, Tate & Cuite, P.L.L.C., and has been an owner of Computer Data Litigation Services, LLC and First Capital Management, LLC. Mr. Woodrum is currently the Chairman of our audit committee and compensation committee. From 1965 to 1975, Mr. Woodrum was employed by Peat, Marwick, Mitchell & Co., serving as partner in charge of the tax department during the final two years. From 1975 to 1980 he served as CFO for BancOklahoma Corp. and Bank of Oklahoma. From 1980 to 1984 Mr. Woodrum served as a partner in charge of the tax department at Peat, Marwick, Mitchell & Co. One of Mr. Woodrum s partners at Woodrum, Kemendo, Tate & Cuite, P.L.L.C., Ben Kemendo, is the son of Chris Kemendo, Jr.

Our executive officers are elected by, and serve at the pleasure of, our board of directors. Our directors serve terms of one year each, with the current directors serving until the 2006 annual meeting of stockholders, and in each case until their respective successors are duly elected and qualified.

None of our directors currently serves as a director of any other company which is required to file periodic reports under the Securities Exchange Act of 1934.

Board Committees

Our board of directors has established an audit committee, whose principal functions are to assist the board in monitoring the integrity of our financial statements, the independent auditor s qualifications and independence, the performance of our independent auditors and our compliance with legal and regulatory requirements. The audit committee has the sole authority to retain and terminate our independent auditors and to approve the compensation paid to our independent auditors. The audit committee is also responsible for overseeing our internal audit function. The audit committee is comprised of two independent directors, consisting of Messrs. Kemendo and Woodrum, with Mr. Woodrum acting as the chairman. Our board of directors has determined that each member of the audit committee qualifies as an audit committee financial expert under the rules of the SEC adopted pursuant to requirements of the Sarbanes-Oxley Act of 2002 (see the biographical information for each of Messrs. Kemendo and Woodrum, infra, in this discussion of Directors and Executive Officers.) Each of Messrs. Kemendo and Woodrum further qualifies as independent in accordance with the applicable regulations adopted by the SEC and American Stock Exchange.

Our board of directors has established a compensation committee, whose principal function is to make recommendations regarding the compensation of the Company s officers. In accordance with the rules of the American Stock Exchange (on which our shares are listed), the compensation of our chief executive officer is recommended to the Board (in a proceeding in which the chief executive officer does not participate) by the compensation committee. The compensation committee is comprised of two independent directors, consisting of Messrs. Kemendo and Woodrum, with Mr. Woodrum acting as the chairman. Compensation for all other officers is also recommended to the Board for determination, by the compensation committee.

We currently do not have a nominating committee. Instead, in accordance with the rules of the American Stock Exchange, the independent directors (currently, Messrs. Crawford, Kemendo and Woodrum) fulfill the role of a nominating committee. Since our inception in 2000, we have had only six directors, five of whom continue to serve at this time. On the only occasion when a vacancy occurred (following a resignation), the new director was unanimously approved by the remaining directors. Therefore, the Board has not felt it necessary to have a standing nominating committee to deal with its infrequent changes in membership. If and when future vacancies occur, the Board would consider director nominees recommended by shareholders, as well as director nominees recommended by a majority of the directors who are then independent. The board does not have a formal policy regarding the consideration of, procedures to be followed by, minimum requirements of or process for identifying or evaluation nominees recommended by security holders.

Our board may establish other committees from time to time to facilitate our management.

Director Compensation

All outside directors are currently compensated with a stipend of $500 per month plus $500 for each directors meeting attended. No director receives a salary as a director.

Compensation Committee Interlocks and Insider Participation

None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

Section 16(a) Beneficial Ownership Reporting Compliance

Based solely upon a review of Forms 4 furnished to us during our most recent fiscal year, we know of no director, officer or beneficial owner of more than ten percent of our common stock who failed to file on a timely basis reports of beneficial ownership of the our common stock as required by Section 16(a) of the Securities Exchange Act of 1934, as amended.

Code of Ethics

We have adopted a code of ethics that applies to our principal executive officer, principal financial officer and principal accounting officer or persons performing similar functions (as well as its other employees and directors). The Company undertakes to provide any person without charge, upon request, a copy of such code of ethics. Requests may be directed to Arena Resources, Inc., 4920 S. Lewis Ave., Suite 107, Tulsa, Oklahoma 74105, attention William R. Broaddrick, or by calling (918) 747-6060.

Item 11: Executive Compensation

The following table sets forth information concerning the compensation paid by us for the three most recent fiscal years to our chief executive officer and our other two executive officers.

Summary Compensation Table

		Annual Compensation		Long-Term Compensation Awards
Name and Principal Position	**Year**	**Salary[(1)]**	**Bonus**	**Securities Underlying Options[(2)]**
Lloyd T. Rochford				
President and Chief Executive Officer	2003	$ 36,000	$ -	$229,742
	2004	$ 36,000	$ -	$ -
	2005	$ 36,000	$ -	$376,170
Stanley M. McCabe				
Chairman of the Board	2003	$ 36,000	$ -	$229,742
	2004	$ 36,000	$ -	$ -
	2004	$ 36,000	$ -	$376,170
William R. Broaddrick				
Vice President, Chief Financial Officer	2003	$ 47,927	$ -	$459,484
	2004	$ 51,500	$ 4,167	$ -
	2004	$ 55,667	$ 2,458	$ -

(1) Mr. Broaddrick s salary reflects raises that occurred in mid-year to increase his annual salary to $50,000 during 2003, $54,000 during 2004 and $59,000 during 2005. There are no current plans to change any officers salary from their level at December 31, 2005.

(2) The fair value of the options issued in 2003 was estimated on the dates granted using the Black-Scholes option pricing model with the following weighted average assumptions: dividend yield of 0%; expected volatility of 36.2%; risk-free interest rate of 2.9% and expected lives of 5.0 years. The weighted average remaining contractual life of the options issued in 2003 at December 31, 2005 was 2.3 years. The fair value of the options issued in 2005 was estimated on the dates granted using the Black-Scholes option pricing model with the following weighted average assumptions: dividend yield of 0%; expected volatility of 32.3%; risk-free interest rate of 3.7% and expected lives of 5.0 years. The weighted average remaining contractual life of the options issued in 2005 at December 31, 2005 was 4.0 years.

Employee Benefit Plans

Equity Incentive Plan. In March 2003, our board of directors adopted an executive stock option plan which was subsequently approved by our shareholders at our annual meeting in July 2003 and further amended by our shareholders at our annual meetings in December 2004 and 2005. The executive stock option plan is intended to promote continuity of management and to provide increased incentive and personal interest in our welfare by those key employees who are primarily responsible for shaping and carrying out our long-range plans and securing our continued growth and financial success. In addition, by encouraging stock ownership by directors who are not our employees, the executive stock option plan is intended to attract and retain qualified directors.

The plan is administered by Messrs. Rochford and McCabe, and they have the authority to select the key employees and non-employee directors to be participants in the plan, to determine the awards to be granted to participants and the number of shares covered by such awards, to set the terms and conditions of such awards and to establish, amend or waive rules for the administration of the plan.

Any of our key employees, including any of our executive officers or directors, is eligible to be granted awards by plan administrators. The plan authorizes the grant of stock options to key employees, all of which have been non-qualified stock options. Our non-employee directors are only eligible to be granted non-qualified stock options under the plan.

The plan provides that up to a total of 2,000,000 shares of common stock, subject to adjustment to reflect stock dividends and other capital changes, are available for granting of awards under the executive stock option plan. 1,475,000 of the shares available for grant under the plan have been reserved for issuance pursuant to options granted during 2003 and 2005.

The following table provides information regarding option exercises and fiscal year-end option values calculated by determining the difference between the closing price of our common stock at December 31, 2005 and the exercise price of the options.

	Shares Acquired on Exercise	Value Realized ($)	Number of Unexercised Securities Underlying Options/SARs at FY-End (#) Exercisable/ Unexercisable	Value of Unexercisable In-The-Money Options/SARs at FY-End ($) Exercisable/ Unexercisable
Lloyd T. Rochford	0	0	50,000/200,000	$1,195,000/$4,780,000
Stanley M. McCabe	0	0	50,000/200,000	$1,195,000/$4,780,000
William R. Broaddrick	0	0	100,000/150,000	$2,390,000/$3,585,000
Phillip W. Terry	0	0	100,000/150,000	$2,390,000/$3,585,000
Raymond H. Estep	0	0	40,000/60,000	$956,000/$1,434,000
Clayton E. Woodrum	0	0	20,000/42,500	$456,000/$969,000
Charles M. Crawford	0	0	20,000/42,500	$478,000/$1,017,750
Chris V. Kemendo, Jr.	0	0	20,000/55,000	$478,000/$1,314,500
Danny Palmer	0	0	0/50,000	$0/$965,000
Stephanie Mefford	0	0	0/25,000	$0/$482,500
Kim Nichols	0	0	0/50,000	0/$337,500

The following table sets forth information concerning our executive stock option plan as of December 31, 2005.

	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under compensation plans (excluding securities in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	1,425,000	5.55	575,000
Equity compensation plans not approved by security holders	-	-	-
Total	1,425,000	5.55	575,000

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

The following table sets forth, as February 28, 2006, information regarding the beneficial ownership of our common stock: (i) by each of our directors and executive officers; (ii) by all directors and executive officers as a group; and (iii) by all persons known to us to own 5% or more of our outstanding shares of common stock. The mailing address for each of the persons indicated is our corporate headquarters.

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and includes, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the stockholders identified in the following table have sole voting and investment power with respect to all shares shown as beneficially owned by them.

	Shares of Common Stock Beneficially Owned	
Name	**Number**	**Percent**
Lloyd T. Rochford	1,212,600 (1)	9%
Stanley M. McCabe	1,213,000 (2)	9%
William R. Broaddrick	154,500 (3)	1%
Charles M. Crawford	32,500 (4)	*
Chris V. Kemendo, Jr	35,100 (5)	*
Clayton E. Woodrum	22,500 (6)	*
All directors and executive officers	2,670,200 (7)	20%

(1) Includes 50,000 shares issuable upon the exercise of stock options that are currently exercisable and 50,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(2) Includes 50,000 shares issuable upon the exercise of stock options that are currently exercisable and 50,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(3) Includes 100,000 shares issuable upon the exercise of stock options that are currently exercisable and 50,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(4) Includes 20,000 shares issuable upon the exercise of stock options that are currently exercisable and 12,500 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(5) Includes 20,000 shares issuable upon the exercise of stock options that are currently exercisable and 15,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(6) Includes 20,000 shares issuable upon the exercise of stock options that are currently exercisable and 2,500 shares issuable upon exercise of stock options that are exercisable within 60 days..
(7) Includes 260,000 shares issuable upon the exercise of stock options that are currently exercisable and 120,000 shares issuable upon the exercise of stock options that are exercisable within 60 days by all executive officers and directors.
* Represents beneficial ownership of less than 1%

Percentage ownership calculations for any stockholder listed above are based on 13,226,702 shares of our common stock outstanding as of February 28, 2006.

Item 13: **Certain Relationships and Related Transactions**

In July 2002, we borrowed $200,000 from each of Messrs. Rochford and McCabe, which debts are evidenced by notes payable which mature on January 1, 2007. The notes bear interest at a rate of 10% per annum, and are secured by our assets (although such notes are subordinate to our credit facility with our primary commercial lender).

Item 14: **Principal Accountant Fees and Services**

The firm of Hansen, Barnett & Maxwell, (HBM) has served as the Company s independent auditors since 2000. The Audit Committee selected HBM as the independent auditors of the Company for the fiscal year ending December 31, 2005, and the Audit Committee has selected HBM to serve in the same capacity for the fiscal year ending December 31, 2006. The Audit Committee has adopted a policy that requires advance approval of all audit, audit-related, tax services and other services performed by the independent auditor.

Fees and Independence

Audit Fees. HBM billed the Company an aggregate of $75,000 and $60,548 for professional services rendered for the audit of the Company s financial statements for the years ended December 31, 2005 and 2004, respectively, and its reviews of the Company s financial statements included in its Form 10-QSB s for the first three quarters of 2005, 2004.

Audit Related Fees. HBM billed the Company $5,500 and $78,998 for the years ended December 31, 2005 and 2004, respectively, for its services in connection with the review of the Company s registration statement on Form S-3 (which was filed with the SEC in 2005), the review of the Company s registration statement on Form SB-2 (which was filed with the SEC in 2004) and for the audit of the Fuhrman-Mascho property acquisition, and which are not included in the audit fees identified above.

Tax Fees. HBM billed the Company an aggregate of $5,000 and $3,000 for professional services rendered for tax compliance, tax advice and tax planning for the years ended December 31, 2005 and 2004.

All Other Fees. No other fees were billed by HBM to the Company during 2005 and 2004.

The Audit Committee of the Board of Directors has determined that the provision of services by HBM described above is compatible with maintaining HBM s independence as the Company s principal accountant.

Item 13: **Exhibits**

(a) Financial Statements
See Index to Financial Statements on page 50

(b) Exhibits

3.1 Articles of Incorporation of Arena Resources, Inc. (i)

3.2 By-Laws of Arena Resources, Inc. (i)

10.1 Business Loan Agreement, dated as of April 14, 2004, among Arena Resources, Inc. and MidFirst Bank, N.A. (ii)

10.2 Business Loan Agreement, dated as of May 7, 2004, among Arena Resources, Inc. and MidFirst Bank, N.A. (ii)

10.3 Business Loan Agreement, dated as of November 16, 2004, among Arena Resources, Inc. and MidFirst Bank, N.A. (iii)

10.4 East Hobbs Purchase and Sales Agreement Dated April 22, 2004 (ii)

10.5 Fuhrman-Mascho Purchase and Sales Agreements Dated December 1, 2004 (iii)

23.1 Consent of Lee Keeling and Associates, Inc., Independent Petroleum Engineers

23.2 Consent of Hansen, Barnett & Maxwell, Independent

31.1 Certification of CEO

31.2 Certification of CFO

32.1 Section 1350 Certification - CEO

32.2 Section 1350 Certification - CFO

(i) Incorporated herein by reference to the exhibits to Arena Resources, Inc. s Form SB-1 filed January 2, 2001 (SEC File No. 333-46164).

(ii) Incorporated herein by reference to the exhibits to Arena Resources, Inc. s From 8-K filed May 18, 2004.

(iii) Incorporated herein by reference to the exhibits to Arena Resources Form 10-KSB filed March 17, 2005.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on behalf by the undersigned, thereunto duly authorized.

ARENA RESOURCES, INC.

By: /s/ Lloyd T. Rochford

Mr. Lloyd T. Rochford, President,
Chief Executive Officer

Date: March 15, 2006

By: /s/ Stanley McCabe

Mr. Stanley McCabe
Treasurer, Secretary

Date: March 15, 2006

By: /s/ William R. Broaddrick

Mr. William R. Broaddrick
Chief Financial Officer

Date: March 15, 2006

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

By: /s/ Lloyd T. Rochford

Mr. Lloyd T. Rochford
Director

Date: March 15, 2006

By: /s/ Stanley McCabe

Mr. Stanley McCabe
Director

Date: March 15, 2006

By: /s/ Charles Crawford

Mr. Charles Crawford
Director

Date: March 15, 2006

By: /s/ Chris V. Kemendo, Jr.

Mr. Chris V. Kemendo, Jr.
Director

Date: March 15, 2006

By: /s/ Clayton E. Woodrum

Mr. Clayton E. Woodrum
Director

Date: March 15, 2006

ARENA RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS

HANSEN, BARNETT & MAXWELL
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Registered with the Public Company
Accounting Oversight Board

BAKER TILLY
INTERNATIONAL

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of Arena Resources, Inc.

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

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits 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, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

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

As discussed in Note 5 to the financial statements, the Company changed its method of recognizing asset retirement obligations in 2003.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Arena Resources, Inc. s internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 14, 2006 expressed an unqualified opinion thereon.

HANSEN, BARNETT & MAXWELL

Salt Lake City, Utah
March 14, 2006

ARENA RESOURCES, INC.
BALANCE SHEETS

December 31,	2005	2004
ASSETS		
Current Assets		
Cash	$ 4,317,114	$ 1,253,969
Account receivable	3,180,749	1,149,513
Joint interest billing receivable	140,561	61,805
Prepaid expenses	35,436	33,136
Total Current Assets	7,673,860	2,498,423
Property and Equipment, Using Full Cost Accounting		
Oil and gas properties subject to amortization	69,770,685	34,457,137
Drilling advances	-	900,000
Equipment	26,687	26,687
Deposits on drilling rig	1,191,126	-
Office equipment	106,177	60,401
Total Property and Equipment	71,094,675	35,444,225
Less: Accumulated depreciation and amortization	(4,346,628)	(1,565,124)
Net Property and Equipment	66,748,047	33,879,101
Total Assets	$ 74,421,907	$ 36,377,524
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 6,038,691	$ 1,805,865
Income taxes payable	329,986	-
Accrued liabilities	221,519	34,800
Total Current Liabilities	6,590,196	1,840,665
Long-Term Liabilities		
Notes payable	-	10,000,000
Notes payable to related parties	400,000	400,000
Put option	-	95,033
Asset retirement liability	1,515,347	1,267,993
Deferred income taxes	7,187,609	1,971,990
Total Long-Term Liabilities	9,102,956	13,735,016
Stockholders' Equity		
Preferred stock - $0.001 par value; 10,000,000 shares authorized; no shares issued or outstanding	-	-
Common stock - $0.001 par value; 100,000,000 shares authorized; 13,099,702 shares and 9,132,910 shares outstanding, respectively	13,100	9,133
Additional paid-in capital	45,331,234	15,258,352
Options and warrants outstanding	1,483,807	3,213,159
Deferred compensation	(115,545)	(234,277)
Retained earnings	12,016,159	2,555,476
Total Stockholders' Equity	58,728,755	20,801,843

Total Liabilities and Stockholders' Equity	$ 74,421,907	$ 36,377,524

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

ARENA RESOURCES, INC.
STATEMENTS OF OPERATIONS

For the Years Ended December 31,	2005	2004	2003
Oil and Gas Revenues	$ 25,843,077	$ 8,482,130	$ 3,665,477
Costs and Operating Expenses			
Oil and gas production costs	3,832,486	1,975,835	1,149,136
Oil and gas production taxes	1,939,739	629,703	269,563
Depreciation, depletion and amortization	2,781,504	1,011,602	360,282
Accretion expense	102,585	53,729	32,212
General and administrative expense	1,365,590	874,850	778,774
Total Costs and Operating Expenses	10,021,904	4,545,719	2,589,967
Other Income (Expense)			
Gain from change in fair value of put options	95,033	68,251	47,699
Other financing expense	(597,773)	-	-
Interest expense	(229,624)	(155,936)	(38,798)
Net Other Income (Expense)	(732,364)	(87,685)	(8,901)
Income Before Provision for Income Taxes and Cumulative Effect of Change in Accounting Principle	15,088,809	3,848,726	1,084,411
Provision for Deferred Income Taxes	(5,628,126)	(1,397,074)	(402,455)
Income Before Cumulative Effect of Change in Accounting Principle	9,460,683	2,451,652	681,956
Cumulative Effect of Change in Accounting Principle	-	-	(11,813)
Net Income	$ 9,460,683	$ 2,451,652	$ 670,143
Basic Earnings Per Share			
Before cumulative effect of change in accounting principle	$ 0.85	$ 0.31	$ 0.10
Net Income	0.85	0.31	0.10
Diluted Earnings Per Share			
Before cumulative effect of change in accounting principle	$ 0.75	$ 0.28	$ 0.09
Net Income	0.75	0.28	0.09

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

ARENA RESOURCES, INC.
STATEMENTS OF STOCKHOLDERS EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2003, 2004 AND 2005

	Common Stock						
	Shares	Amount	Additional Paid-In Capital	Options and Warrants Outstanding	Deferred Compensation	Retained Earnings	Total Stockholders' Equity
Balance December 31, 2002	6,282,056	$ 6,282	$ 5,287,189	$ 382,040	$ -	$ (566,319)	$ 5,109,192
Issuance for cash, net	790,294	790	1,274,256	436,154	-	-	1,711,200
Issuance of employee stock options	-	-	-	660,000	(660,000)	-	-
Issuance of warrants as consulting fee for 2002 offering	-	-	(15,922)	15,922	-	-	-
Cancellation of shares for extension of lock up	(500)	-	-	-	-	-	-
Issuance of common stock for services	13,847	14	75,026	-	-	-	75,040
Warrants exercised	19,400	19	54,883	(20,952)	-	-	33,950
Issuance of common stock in property acquisitions	57,000	57	319,493	-	-	-	319,550
Amortization of deferred compensation	-	-	-	-	221,198	-	221,198
Net income	-	-	-	-	-	670,143	670,143
Balance December 31, 2003	7,162,097	7,162	6,994,925	1,473,164	(438,802)	103,824	8,140,273
Warrants exercised	78,300	78	395,843	(41,796)	-	-	354,125
Issuance for cash, net	1,667,500	1,668	6,469,225	1,781,791	-	-	8,252,684
Issuance of common stock in property acquisitions, net of call option received	225,013	225	1,398,359	-	-	-	1,398,584
Amortization of deferred compensation	-	-	-	-	204,525	-	204,525
Net income	-	-	-	-	-	2,451,652	2,451,652
Balance December 31, 2004	9,132,910	9,133	15,258,352	3,213,159	(234,277)	2,555,476	20,801,843
Warrants exercised for cash, net	2,971,273	2,971	20,194,042	(2,322,392)	-	-	17,874,621
Expiration of warrants	-	-	4,733	(4,733)	-	-	-
Issuance of common stock in property acquisition	25,000	25	340,625	-	-	-	340,650
Issuance for cash, net	970,874	971	9,535,967	-	-	-	9,536,938
Issuance of warrants for services relating to private offering	-	-	-	597,773	-	-	597,773
Cancellation of stock issued in property acquisition	(355)	-	(2,485)	-	-	-	(2,485)
Amortization of deferred compensation	-	-	-	-	118,732	-	118,732
Net income	-	-	-	-	-	9,460,683	9,460,683
Balance December 31, 2005	13,099,702	$ 13,100	$ 45,331,234	$ 1,483,807	$ (115,545)	$ 12,016,159	$ 58,728,755

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

ARENA RESOURCES, INC.
STATEMENTS OF CASH FLOWS

For the Years Ended December 31	2005	2004	2003
Cash Flows From Operating Activities			
Net income	$ 9,460,683	$ 2,451,652	$ 670,143
Adjustments to reconcile net income to net cash provided by operating activities:			
Shares issued for services	-	-	75,040
Warrants issued for financing expense	597,773	-	-
Depreciation, depletion and amortization	2,781,504	1,011,602	360,282
Provision for income taxes	5,628,126	1,397,074	402,455
Gain from change in fair value of put option	(95,033)	(68,251)	(47,699)
Cumulative effect of change in accounting principle	-	-	11,813
Loss on sale of equipment	-	5,586	-
Amortization of deferred compensation	118,732	204,525	221,198
Accretion of discounted liabilities	102,585	83,730	32,212
Changes in assets and liabilities:			
Accounts and joint interest receivable	(2,109,992)	(656,864)	(119,474)
Other changes in deferred income taxes	(82,521)	-	-
Prepaid expenses	(2,300)	(4,201)	(27,807)
Accounts payable and accrued liabilities	4,419,545	1,570,831	74,787
Net Cash Provided by Operating Activities	20,819,102	5,995,684	1,652,950
Cash Flows From Investing Activities			
Proceeds from sale of property and equipment	735,000	10,500	-
Cash payments on purchase of East Hobbs	-	(1,028,000)	-
Cash payments on purchase of Furhman-Mascho properties	-	(711,802)	-
Purchase and development of oil and gas properties	(34,665,614)	(4,802,141)	(3,050,558)
Maturity of long-term investment	-	25,234	51,268
Purchase of machinery and office equipment	(1,236,902)	(41,423)	(30,992)
Net Cash Used in Investing Activities	(35,167,516)	(6,547,632)	(3,030,282)
Cash Flows From Financing Activities			
Proceeds from issuance of common stock and warrants, net of offering costs	9,536,938	8,383,557	1,580,328
Proceeds from exercise of warrants, net of offering costs	17,874,621	354,124	33,950
Issuance of note payable	-	2,000,000	-
Payment of notes payable	(10,000,000)	(10,008,440)	-
Collection of common stock subscription receivable	-	-	157,500
Payment of accrued dividends to preferred stockholders	-	-	(114,685)
Net Cash Provided by Financing Activities	17,411,559	729,241	1,657,093
Net Increase in Cash	3,063,145	177,293	279,761
Cash at Beginning of Period	1,253,969	1,076,676	796,915
Cash at End of Period	$ 4,317,114	$ 1,253,969	$ 1,076,676

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

ARENA RESOURCES, INC.
STATEMENTS OF CASH FLOWS (CONTINUED)

For the Years Ended December 31	2005	2004	2003
Supplemental Cash Flow Information			
Cash paid for income taxes	$ 82,521	$ -	$ -
Cash paid for interest	$ 199,624	$ 158,950	$ 38,798
Non-Cash Investing and Financing Activities			
Common stock issued for properties	$ 340,650	$ 34,500	$ 319,550
Asset retirement obligation incurred in property acquisition and development	144,769	570,029	338,271
East Hobbs property was acquired as follows:			
Fair value of assets acquired	$ -	$ 10,354,964	$ -
Liabilities assumed	-	(78,654)	-
Notes payable incurred	-	(9,008,440)	-
Common stock issued	-	(239,870)	-
Cash paid	$ -	$ 1,028,000	$ -
Fuhrman-Mascho property was acquired as follows:			
Fair value of assets acquired	$ -	$ 11,479,742	$ -
Liabilities assumed	-	(513,247)	-
Note payable incurred, net of $30,000 unamortized discount	-	(8,970,000)	-
Put options issued	-	(160,379)	-
Common stock issued	-	(1,260,091)	-
Call options received	-	135,777	-
Cash paid	$ -	$ 711,802	$ -

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

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations Arena Resources, Inc. (the Company) is a Nevada corporation that owns interests in oil and gas properties located in Oklahoma, Texas, Kansas and New Mexico. The Company is engaged primarily in the acquisition, exploration and development of oil and gas properties and the production and sale of oil and gas.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Cash The Company had deposits with a bank that are $4,217,114 in excess of federally insured limits at December 31, 2005.

Oil and Gas Properties The Company uses the full cost method of accounting for oil and gas properties. Under this method, all costs associated with acquisition, exploration, and development of oil and gas properties are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. Capitalized costs are categorized either as being subject to amortization or not subject to amortization.

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves and estimated future costs to plug and abandon wells and costs of site restoration, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent engineers. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Following is a table showing our total depletion and amortization and depletion per barrel-of-oil-equivalent rate, by year for the years ended December 31, 2005, 2004 and 2003.

	For the Years Ended December 31,		
	2005	**2004**	**2003**
Depletion	$ 2,757,187	$ 997,694	$ 360,282
Depletion rate, per barrel-of-oil-equivalent (BOE)	$ 5.42	$ 4.47	$ 2.79

In addition, capitalized costs less accumulated amortization and related deferred income taxes shall not exceed an amount (the full cost ceiling) equal to the sum of: the present value of estimated future net revenues computed by applying current prices of oil and gas reserves to estimated future production of proved oil and gas reserves, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus the cost of properties not being amortized; plus the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less income tax effects related to differences between the book and tax basis of the properties.

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

Support and Office Equipment Depreciation of support and office equipment is computed using the straight-line method over the estimated useful lifes of the assets which are currently five to seven years. Depreciation expense was $22,659, $13,908 and $9,950 for the years ended December 31, 2005, 2004 and 2003, respectively.

Fair Values of Financial Instruments The carrying amounts reported in the balance sheets for accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the immediate or short-term maturity of these financial instruments. The carrying amounts reported for notes receivable, notes payable, and long-term debt approximate fair value because the underlying instruments are at interest rates which approximate current market rates.

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

Income Taxes Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes. Deferred taxes are provided on differences between the tax bases of assets and liabilities and their reported amounts in the financial statements, and tax carry forwards. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the provision for income taxes.

Earnings Per Share Basic earnings per share is computed by dividing net income by the weighted-average number of common shares outstanding during the year. Diluted earnings per share is calculated to give effect to potentially issuable dilutive common shares.

Major Customers During the year ended December 31, 2005, sales to two customers represented 72% and 12% of total sales, respectively. At December 31, 2005, these two customers made up 77% and 8% of accounts receivable, respectively. During the year ended December 31, 2004, sales to two customers represented 43% and 31% of total sales, respectively. At December 31, 2004, these two customers made up 43% and 22% of accounts receivable, respectively. During the year ended December 31, 2003, sales to three customers represented 51%, 19% and 11% of total sales, respectively. At December 31, 2003, these three customers made up 46%, 16% and 17% of accounts receivable, respectively.

Stock-Based Employee Compensation In 2003 and 2005, the Company issued stock options to directors and employees, which are described more fully in Note 7. The Company applies the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations in accounting for its stock-based compensation awards to employees. The Company recognized compensation expense relating to those stock options of $118,732, $204,525 and $221,198 for the years ended December 31, 2005, 2004 and 2003, respectively.

Alternately, Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation* (SFAS No. 123), allows companies to recognize compensation expense over the related service period based on the grant date fair value of the stock option awards. The following table illustrates the effect on net income and basic and diluted earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation:

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

For the Years Ended December 31,	2005	2004	2003
Net income, as reported	$ 9,460,683	$ 2,451,652	$ 670,143
Add: Stock based employee compensation expense included in net income, net of related tax effects	74,444	128,365	139,355
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(555,051)	(345,068)	(372,935)
Pro Forma Net Income	$ 8,980,076	$ 2,234,949	$ 436,563
Income Per Common Share			
Basic, as reported	$ 0.85	$ 0.31	$ 0.10
Basic, pro forma	0.80	0.28	0.06
Diluted, as reported	$ 0.75	$ 0.28	$ 0.09
Diluted, pro forma	0.71	0.26	0.06

Stock-Based Compensation to Non-Employees The Company accounts for its stock-based compensation issued to non-employees using the fair value method in accordance with SFAS No. 123, Accounting for Stock-Based Compensation. Under SFAS No. 123, stock-based compensation is determined as either the fair value of the consideration received or the fair value of the equity instruments issued, whichever is more reliably measurable. The measurement date for these issuances is the earlier of the date at which a commitment for performance by the recipient to earn the equity instruments is reached or the date at which the recipient s performance is complete.

Cumulative Effect of Change in Accounting Principle The Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003. In accordance with the transition provisions of SFAS No. 143, on that date the Company recorded asset retirement costs and liabilities and recorded an adjustment for the cumulative effect on prior years of adopting SFAS No. 143 in the amount of $11,813 as a reduction in earnings, which had no effect on basic or diluted earnings per share.

Recent Accounting Pronouncements In December 2004, the FASB issued Statement No. 123 (Revised 2004), *Share-Based Payment* (Statement 123(R)). Statement 123(R) revises Statement No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*. Statement 123(R) requires companies to recognize the cost of employee services received in exchange for stock options and awards of equity instruments based on the grant-date fair value of such options and awards. The Company is required to adopt Statement 123(R) on a prospective basis beginning on January 1, 2006, which will result in the recognition of the remaining unrecognized stock-based compensation computed on a fair value basis over the remaining vesting period. The effect of adopting Statement 123(R) will result in recognition of $391,466 of additional after-tax compensation during the year ending December 31, 2006 from options outstanding at December 31, 2005.

In December 2004, the FASB issued SFAS Statement No. 153, *Exchanges of Non-monetary Assets an amendment of APB Opinion No. 29.* This Statement amends APB Opinion 29 to eliminate the exception for non-monetary exchanges of similar productive assets and replaces it with a general exception for exchanges of non-monetary assets that do not have commercial substance. A non-monetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The Company implemented this standard on January 1, 2006 and will not have a material impact to the Company.

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

In March 2005, the FASB issued FASB Interpretation (FIN) 47, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143.* FIN 47 clarifies that conditional asset retirement obligations meet the definition of liabilities and should be recognized when incurred if their fair values can be reasonably estimated. The Company adopted the provisions of FIN 47 effective December 31, 2005. The adoption of FIN 47 had no impact on the Company s financial position or results of operations.

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections a replacement of APB Opinion No. 20 and FASB Statement No. 3.* SFAS No. 154 applies to all voluntary changes in accounting principle or when an accounting pronouncement does not include specific transition provisions and changes the requirements for the accounting for and reporting of a change in accounting principle. This statement requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period specific effects or the cumulative effect of the change. The Company implemented this standard on January 1, 2006 and will not have a material impact to the Company.

In April 2005, the FASB issued FSP 19-1, *Accounting for Suspended Well Costs.* FSP 19-1 provides guidance on the accounting for exploratory well costs. It states that for companies using the successful efforts method of accounting for capitalized costs, if an exploratory well is drilled but is not found to have proved reserves, even if it shows reserves, but the reserves cannot be considered proved, then the capitalized costs of drilling the well are expensed. This pronouncement does not impact the accounting for the Company because the Company does not use the successful efforts method of accounting for capitalized costs.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140.* SFAS No. 155 resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, *Application of Statement 133 to Beneficial Interests in Securitized Financial Assets.* SFAS No. 155 will become effective for the Company s fiscal year after September 15, 2006. The impact of SFAS No. 155 will depend on the nature and extent of any new derivative instruments entered into after the effective date.

NOTE 2 EARNINGS PER SHARE INFORMATION

For the Years Ended December 31,	**2005**	**2004**	**2003**
Income before cumulative effect of change in accounting principle	$ 9,460,683	$ 2,451,652	$ 681,956
Cumulative effect of change in accounting principle	-	-	(11,813)
Net Income	$ 9,460,683	$ 2,451,652	$ 670,143
Basic Weighted-Average Common Shares Outstanding	11,164,070	7,873,213	6,759,858
Effect of dilutive securities			
Warrants	838,773	524,173	231,476
Stock options	597,263	296,792	250,342
Diluted Weighted-Average Common Shares Outstanding	12,600,106	8,694,178	7,241,676
Basic Earnings Per Share			
Income before cumulative effect of change in accounting principle	$ 0.85	$ 0.31	$ 0.10
Net income	0.85	0.31	0.10
Diluted Earnings Per Share			
Income before cumulative effect of change in accounting principle	$ 0.75	$ 0.28	$ 0.09
Net Income	0.75	0.28	0.09

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 3 ACQUISITION OF OIL AND GAS PROPERTIES

East Hobbs On May 7, 2004, the Company acquired an 82.24% working interest, 67.60% net revenue interest, in the East Hobbs San Andres Property mineral lease (East Hobbs) located in Lea County, New Mexico. Although the Purchase and Sales Agreement transferred the revenue and the related operating costs from East Hobbs to Arena beginning March 1, 2004, Arena did not control the property interests until May 7, 2004. As a result, the acquisition date for accounting purposes was May 7, 2004 and the East Hobbs operations have been included in the results of operations of Arena from May 7, 2004. Revenues and operating costs for the months of March and April were treated as adjustments to the purchase price.

At the date of acquisition, East Hobbs was comprised of 21 operating oil and gas wells that were unitized into one lease prior to the acquisition. The Company purchased East Hobbs for its current production and cash flow, as well as for the drilling and secondary recovery opportunities from the property. The Company paid $10,008,440 to the sellers, including $9,008,440 paid directly from borrowings under a credit facility and a bridge financing from a bank described more fully in Note 4. In addition, the Company paid acquisition costs of $28,000 and issued 15,000 shares of common stock valued at $90,000, or $6.00 per share, and 25,000 shares of common stock valued at $149,750, or $5.99 per share, as a finder s fee on the East Hobbs San Andres Property acquisition. The total acquisition cost was allocated to the assets acquired and the liabilities assumed as follows:

Accounts receivable	$	165,544
Oil and gas properties subject to amortization		10,189,480
Total Assets		10,355,024
Accounts payable		(21,872)
Asset retirement obligation		(56,782)
Total Liabilities Assumed		(78,654)
Net Asset Acquired	$	10,276,370

Furhman-Mascho On November 18, 2004, Arena Resources, Inc. entered into a binding letter of intent to acquire 100% of the working interest, 75% of the net revenue interest, of the Fuhrman-Mascho Property mineral leases under the terms of Asset Purchase Agreements (the Agreements). Under the terms of the Agreements, the sellers transferred effective control of the property to the Company on December 1, 2004 without restrictions. Accordingly, the acquisition date was December 1, 2004. The results of operations of the Fuhrman-Mascho property have been included in the results of operations of the Company from December 1, 2004.

At the date of acquisition, Fuhrman-Mascho property consisted of 84 leases with a total of 174 operating oil and gas wells. The Company purchased Fuhrman-Mascho for its current production and cash flow, as well as for the drilling and development opportunities from the property. On December 20, 2004, the Company made cash payments to the sellers of $9,667,381, issued the sellers 149,658 shares of common stock valued at $1,050,091 or $7.00 per share based on the market value of the common stock over the 2-day period before and after November 18, 2004, issued the sellers put options entitling the sellers to demand that the Company reacquire the 149,658 shares of common stock at $7.00 per share from November 1, 2006 through November 30, 2006, valued at $160,379 using the Black-Scholes option pricing model, and received call options from the sellers entitling the Company to reacquire the 149,658 shares of common stock at $8.50 per share from the date issued through November 1, 2006 and valued at $135,777 using the Black-Scholes option pricing model. In addition, the Company paid acquisition costs of $44,421 and issued 30,000 shares of common stock as a consulting and finder s fee, valued at $210,000, or $7.00 per share. The consideration paid or issued on December 20, 2004 was discounted to December 1, 2004 at 5% and resulted in recognition of an unamortized discount of $30,000 at December 1, 2004. The acquisition was funded through the use of cash on hand and a credit facility secured from the Company s principal lender. The acquisition cost was allocated to the assets acquired and the liabilities assumed as follows:

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

Oil and gas properties subject to amortization	$	11,479,742
Asset retirement obligation		(513,247)
Net Assets Acquired	$	10,966,495

The following unaudited pro forma information is presented to reflect the operations of the Company as if the acquisitions of the East Hobbs and the Fuhrman-Mascho properties had been completed on January 1, 2004 and 2003, respectively:

For the Years Ended December 31,		**2004**		**2003**
		(Unaudited)		
Oil and Gas Revenues	$	11,493,181	$	7,885,740
Income from Operations Before Cumulative Effect of Change in Accounting Principle		2,833,800		1,037,061
Net Income		2,833,800		1,025,248
Basic Income Per Common Share				
Income before cumulative effect of change in accounting principle	$	0.36	$	0.15
Net income		0.36		0.15
Basic Income Per Common Share				
Income before cumulative effect of change in accounting principle	$	0.33	$	0.14
Net income		0.33		0.14

The full year of operations from both of these properties was included in our income statement for the year ended December, 31, 2005.

Other Acquisitions On October 28, 2004, the Company issued 5,000 shares of common stock to an unrelated party as a finder s fee in connection with the purchase of a 70% interest in the Gibralter well in Mississippi. The shares were valued at $34,500, or $6.90 per share, based on the market value of the common stock on the date issued. Arena paid $214,507 of the costs to drill the exploratory well in exchange for the jointly-operated working interest in the well.

During 2005, the Company acquired working interests in leases near its Fuhrman Mascho properties acquired in 2004. The working interests acquired ranged from 20.2% to 100%, and the net revenue interest ranted from 16.1% to 79.2%. Total acquisition costs, including 5,000 shares of restricted common stock valued at $15.81 per share, or $79,050, totaled $1,406,588.

During 2005, the Company also acquired the lease rights to a total of 19,840 acres in Hamilton and Greeley Counties, Kansas. Total acquisition costs, including 20,000 shares of restricted common stock valued at $13.08 per share, or $261,600, was $574,546. Subsequent to the acquisition of these leases, the Company sold a partial working interest in four wells the Company drilled and a right of first refusal on wells drilled offsetting those wells. Total funds received for these working interests was $735,000. These funds received were accounted for as an offset to capitalized costs.

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 4 NOTES PAYABLE AND PUT OPTION

Notes Payable On April 14, 2004, the Company established a new $15,000,000 credit facility from a bank with an $8,500,000 initial borrowing base. In April 2005, the Company entered into an agreement that increased the facility to $50,000,000, with an increased borrowing base of $35,000,000. Any increases in the borrowing base are subject to written consent by the financial institution. The interest rate is a floating rate equal to the 30, 60 or 90 day LIBOR rate plus 2.25%, currently 7.11% per annum, and is payable monthly. Amounts borrowed under the revolving credit facility are due on April 30, 2008. The revolving credit facility is secured by the Company s principal mineral interests. In order to obtain the revolving credit facility, loans from two officers were subordinated to the position of the bank. The Company is required under the terms of the credit facility to maintain a tangible net worth of $12,000,000, maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense and maintain a current asset to current liability ratio of 1-to-1. At December 31, 2005, the Company was in compliance with all covenants and no amounts were outstanding under this credit facility, though $299,029 is reserved under the revolving credit facility as collateral for standby letters of credit issued to various states.

Notes Payable to Related Parties On July 1, 2002, the Board of Directors authorized the Company to borrow up to $500,000 from its officers. On July 26, 2002, the Company borrowed $400,000 from two of its officers. The related notes payable bear interest at 10% per annum. The notes are secured by all mineral interests, rights and equipment of the Company but have been subordinated to the bank revolving credit facility mentioned above. The Board of Directors and the officers agreed to extend the notes to January 1, 2007, under the same terms as the original notes. Based on the borrowing rates available to the Company for bank loans, the fair value of the notes payable to officers was $400,000 at December 31, 2005 and 2004.

Put Option The Company granted a put option in connection with the acquisition of oil and gas properties in December 2004. Under the terms of the put option, the sellers have the right until December 1, 2006, to require the Company to repurchase the 149,658 common shares at $7.00 per share. The put option is a derivative and as such, the liability has been revalued to its fair value at each balance sheet date with adjustments to fair value being recognized as gain on change in fair value of put options. At the date of issuance, the fair value of the liability was $160,379, calculated using the Black-Scholes option pricing model with the following assumptions: 3% risk-free interest rate; 33% volatility; 2 years expected life; and 0% dividend yield. At December 31, 2004, the fair value of the liability was $95,033, calculated using the Black-Scholes option pricing model with the following assumptions: 3% risk-free interest rate; 34% volatility; 2 years expected life; and 0% dividend yield. At December 31, 2005, the fair value of the liability was $0, calculated using the Black-Scholes option pricing model with the following assumptions: 4.38% risk-free interest rate; 43.44% volatility; 1 years expected life; and 0% dividend yield.

NOTE 5 ASSET RETIREMENT OBLIGATION

SFAS 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets, including: 1) the timing of liability recognition; 2) initial measurement of the liability; 3) allocation of asset retirement cost to expense; 4) subsequent measurement of the liability; and 5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long- lived asset and subsequently allocated to expense using a systematic and rational method.

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

At January 1, 2003, the implementation of SFAS No. 143 resulted in a net increase in property and equipment of $217,878. Liabilities increased by $236,718, which represents the establishment of an asset retirement obligation liability. The cumulative effect on prior years of the change in accounting principle of $11,813, net of $7,027 of related tax effects, was recorded in the first quarter of 2003 as a reduction in earnings. The effect of adopting this accounting principle was a $24,873 after-tax decrease in net income during the year ended December 31, 2003.

The adoption of SFAS No. 143 will affect amortization of oil and gas properties on an on-going basis. The increase in oil and gas properties is being amortized as the related oil and gas reserves are produced, and resulted in an increase in depreciation, depletion and amortization for the years ended December 31, 2005, 2004 and 2003 of $21,619, $10,798 and $7,459, respectively. The adoption of SFAS No. 143 also impacted the computation of the ceiling test for the carrying value of oil and gas properties. The ceiling test has changed to include the estimated asset retirement costs in the cost of oil and gas properties and exclude future abandonment costs from the computation of the present value of estimated future net revenues. This change only had a nominal effect on the Company s ceiling test computation at December 31, 2005, 2004 and 2003.

The reconciliation of the asset retirement obligation for the years ended December 31, 2003, 2004 and 2005 is as follows:

Balance, January 1, 2003	$ 236,718
Liabilities incurred	338,270
Accretion expense	32,212
Balance, December 31, 2003	607,200
Liabilities incurred	607,064
Accretion expense	53,729
Balance, December 31, 2004	1,267,993
Liabilities incurred	144,769
Accretion expense	102,585
Balance, December 31, 2005	$ 1,515,347

NOTE 6 STOCKHOLDERS EQUITY

The Company is authorized to issue 100,000,000 common shares, with a par value of $0.001 per share, and 10,000,000 Class A convertible preferred shares, with a par value of $0.001 per share.

Preferred Stock There is no preferred stock outstanding.

Common Stock On August 22, 2002, the Company initiated a $3,000,000 private placement offering of the Company s common stock at $2.50 per share with a detachable warrant exercisable at $5.00 per share through September 30, 2005. From January 1, 2003 to July 15, 2003, the Company issued 790,294 shares of common stock and 790,294 warrants for $1,711,200 in net cash proceeds (net of cash offering costs of $264,535). In addition, 105,196 warrants exercisable at $5.00 per share through September 30, 2005 were issued to placement agents. The net proceeds received were allocated to the common stock and the warrants based upon their relative fair values, with $1,275,046 allocated to the common stock and $436,154 allocated to the warrants. The fair value of the warrants issued was $1,192,626, or $1.37 per warrant, which was determined using the Black-Scholes option pricing model with the following weighted-average assumptions: risk-free interest rate of 1.32%, expected dividend yield of 0%, volatility of 34.7% and an expected life of 2.21 years.

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

In addition, during the year ended December 31, 2003, Arena issued 2,433 additional warrants, with the same terms to placement agents, and 50,000 additional warrants exercisable at $3.00 per share through July 15, 2006, as consulting fees, relating to the shares of common stock and warrants issued during 2002. During the year ended December 31, 2003, $15,922 of the proceeds from the 2002 cash offering proceeds were allocated to the additional warrants, based upon their relative fair value. The offering closed July 15, 2003. The Company issued a total of 1,076,294 units of common stock and warrants to investors under the offering for $2,313,336 in net cash proceeds (net of cash offering costs of $377,399) and issued 157,629 warrants as consulting fees and for services to placement agents.

During the year ended December 31, 2003, warrant holders exercised 19,400 warrants with an exercise price of $1.75 for $33,950. Additionally, in 2003 the Company issued 70,847 shares of common stock for services, which the Company valued at an aggregate total of $394,590, or $5.57 per share. The Company capitalized as part of oil and gas properties $319,550 and the remaining $75,040 was charged to expense.

In August 2004, the Company completed a public offering of common stock and warrants as a unit at $6.10 per unit before underwriters discount and offering costs totaling $1,919,066. The Company issued 1,667,500 shares of common stock and 1,667,500 warrants to purchase common stock at $7.32 per share, through August 9, 2008. In addition, the Company issued options to the underwriters to purchase 145,000 shares of common stock at $9.00 per share and 145,000 warrants at $0.165 per warrant, which entitles them to purchase 145,000 shares of common stock at $7.32. Net proceeds from the offering totaled $8,252,684. These proceeds were allocated as follows: $6,470,893 were allocated to the common stock issued to investors, $1,781,791 were allocated to the warrants. The warrants had a fair value of $2,803,473 or $1.43 per share, which was determined by the Black-Scholes option pricing model using the following assumptions: volatility of 33.3%, risk-free interest rate of 3.2%, dividend yield of 0% and life of 4.0 years.

During the year ended December 31, 2004, warrant holders exercised 66,800 warrants with an exercise price of $5.00 per share and 11,500 warrants with an exercise price of $1.75 per share for $354,125.

In July 2005, the Company issued 970,874 shares of common stock, valued at $10,000,000, or $10.30 per share, in a private placement. As of December 31, 2005, the Company had paid $463,062 in related offering costs. As a part of the negotiation process related to the terms of the private placement, the Company also assigned to certain of the investors call options to purchase 149,658 shares of its common stock at $8.50 per share. The call options were granted in connection with the issuance of shares of the Company s common stock, as partial consideration for its purchase of interests in the Furhman-Mascho lease. The call terms in the option agreements provide the Company with the right to repurchase the shares issued in the Furhman-Mascho transaction at a price of $8.50 per share, at any time prior to November 1, 2006. The option agreements further provide the stockholders who received shares in that transaction the right to require the Company to repurchase its stock from them at a price of $7.00 per share (the public trading price of the common stock at the time of the Furhman-Mascho transaction) for a period of thirty days following November 1, 2006.

The proceeds from the offering have been allocated to the common stock issued and the call options transferred based on their relative fair values and resulted in allocating $9,033,291 to the 970,874 shares of common stock and $503,647 to the 149,658 call options. The market value of the common stock on July 11, 2005 was $12.02 per share. The fair value of the call options was $4.35 per share determined by the Black-Scholes option pricing model using the following assumptions: volatility of 38.3%, risk-free interest rate of 3.6%, dividend yield of 0% and life of 1.0 years.

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

During the year ended December 31, 2005, warrant holders exercised 187,800 warrants with an exercise price of $1.75 per share, 1,117,123 warrants with an exercise price of $5.00 per share, 1,665,350 warrants with an exercise price of $7.32 per share and 1,000 warrants with an exercise price of $9.00 per share for $18,113,627. The Company paid $239,006 in costs related to the call of a portion of those warrants.

Additionally, in 2005 the Company issued 25,000 shares of common stock for services, as described in Note 3. Of the 25,000, 5,000 shares were valued at an aggregate of $79,050, or $15.81 per share, and 20,000 shares were valued at an aggregate of $261,600, or $13.08 per share. The Company capitalized as part of oil and gas properties the full $340,650.

Stock purchase warrants issued and exercised during the years ended December 31, 2005 and 2004 are summarized as follows:

Call Option The Company received a call option in December 2004 in connection with the purchase of oil and gas properties. The option permits the Company to repurchase 149,658 shares of its common stock at $8.50 per share through November 1, 2006. The call option is exercisable at the Company s discretion and was recorded as a reduction of additional paid-in capital based on its fair value of $135,777 on the date received. The fair value of the call option was determined using the Black-Scholes option pricing model with the following assumptions: 3% risk-free interest rate; 34% expected volatility; two year expected life and 0% dividend yield. The call option is part of permanent equity and will not be revalued. This call option was assigned to certain of the investors involved in the Company s private placement offering during 2005 as disclosed further in Note 6.

Warrants issued In connection with the July 2005 private placement, the Company committed to use its best efforts to register the shares with the SEC. The Company was unable to effect the registration within the allotted time and was required to issue 29,126 warrants on December 28, 2005. The exercise price of these warrants is $10.30 and expire December 28, 2010. The Company recognized an expense for the fair value of these warrants of $597,773 from the issuance of these warrants. The fair value of the warrants was determined using the Black-Scholes option pricing model with the following assumptions: 4.32% risk-free interest rate; 43.44% expected volatility; five year expected life and 0% dividend yield.

Stock purchase warrants issued and exercised during the years ended December 31, 2005, 2004, and 2003 are summarized as follows:

	2005		2004		2003	
	Warrants	**Weighted-Average Exercise Price**	**Warrants**	**Weighted-Average Exercise Price**	**Warrants**	**Weighted-Average Exercise Price**
Outstanding at beginning of the year	3,314,923	$ 4.47	1,435,723	$4.47	507,200	$3.58
Issued	29,126	$10.30	1,957,500	$7.46	947,923	$4.89
Expired	(4,650)	$ 4.33	-	$ -	-	$ -
Exercised	(2,971,273)	$ 6.10	(78,300)	$4.52	(19,400)	$1.75
Outstanding at End of Year	368,126	$ 7.69	3,314,923	$6.23	1,435,723	$4.47

Stock purchase warrants outstanding at December 31, 2005 are as follows:

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

Warrants Outstanding	Exercise Price	Weighted-Average Remaining Contractual Life
50,000	$3.00	0.7
145,000	7.49	3.6
144,000	9.00	3.6
29,126	10.30	5.0
368,126		

NOTE 7 EMPLOYEE STOCK OPTIONS

On April 1, 2003 and on August 12, 2003, the Company granted nonqualified stock options to directors and employees to purchase 1,000,000 shares and 50,000 shares of common stock at $3.70 per share and $4.80 per share through April 1, 2008 and August 12, 2008, respectively. Effective July 31, 2003, 50,000 of the options with an exercise price of $3.70 per share were forfeited. The exercise price of the options granted in 2003 was 85% of the market value of the Company s common stock on the dates issued. The Company recognizes compensation expense related to the 15% discount amount of the exercise price from the market price of the stock at the date of grant over the five year vesting period of the options. The Company recognized compensation expense for the years ended December 31, 2003, 2004 and 2005 of $221,198, $204,525 and $118,732, respectively.

Additionally, on January 3, 2005 and October 20, 2005, the Company granted nonqualified stock options to directors and employees to purchase 375,000 shares and 50,000 shares of common stock at $8.30 and $20.85, respectively.

All granted options vest at the rate of 20% each year over five years beginning one year from the date granted. A summary of the status of the stock options as of December 31, 2005 and changes during the years ended December 31, 2005, 2004 and 2003 is as follows:

	2005		2004		2003	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of the year	1,000,000	$3.76	1,000,000	$3.76	-	$ -
Issued	425,000	9.78	-	-	1,050,000	3.75
Forfeited	-	-	-	-	(50,000)	3.70
Outstanding at end of year	1,425,000	5.55	1,000,000	3.76	1,000,000	3.76
Exercisable at end of year	400,000	$3.76	200,000	$3.76	-	$ -
Weighted average fair value of options granted during the year		$3.37		$ -		$1.87

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

Exercise price	Options Outstanding: Number Outstanding	Weighted-Average Remaining Contractual Life (in years)	Number Exercisable
$ 3.70	950,000	2.3	380,000
$ 4.80	50,000	2.6	20,000
$ 8.30	375,000	4.0	-
$ 20.85	50,000	4.9	-
Total outstanding	1,425,000	2.8	400,000
Weighted average exercise price	5.55		

The fair value of the options granted during 2005 and 2003, net of forfeitures, were estimated at the date of grant using a Black-Scholes option-pricing model with the following weighted-average assumptions: expected volatility of 32.3% and 36.2%, respectively, risk-free interest rate of 3.73% and 2.9%, respectively, zero dividend yield and expected lives of 5.0 years.

NOTE 8 RELATED PARTY TRANSACTIONS

In July 2002, the Company borrowed $400,000 from two of its officers under the terms of secured, 10% promissory notes, as more fully described in Note 5.

NOTE 9 COMMITMENTS

Operating Leases Effective January 1, 2004, the Company entered into a two-year extension to an existing operating lease agreement for office space. On March 21, 2005 and effective May 1, 2005, the Company leased additional footage in the same facility. Under terms of the lease, the Company pays $2,500 per month through December 31, 2006. The Company incurred lease expense of $28,000 for the year ended December 31, 2005. The future minimum lease payments under the operating lease agreement as of December 31, 2005 consist of $30,000 due during the year ending December 31, 2006.

Standby Letters of Credit A commercial bank has issued standby letters of credit on behalf of the Company to the states of Texas, Oklahoma and New Mexico totaling $299,029 to allow the Company to do business in those states. The Company intends to renew the standby letters of credit for as long as the Company does business in those states. No amounts have been drawn under the standby letters of credit.

NOTE 10 INCOME TAXES

At December 31, 2005, the Company had alternative minimum income tax payable of $329,986. The provision for income taxes consisted of the following:

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

For the Years Ended December 31,	**2005**	**2004**	**2003**
Current - federal	365,606	-	-
Deferred - state	753,842	265,828	52,772
Deferred - federal	4,508,678	1,131,246	349,683
Provision for income taxes	5,628,126	1,397,074	402,455

The following is a reconciliation of income taxes computed using the U.S. federal statutory rate to the provision for income taxes:

For the Years Ended December 31,	**2005**	**2004**	**2003**
Tax at federal statutory rate (34%)	$ 5,130,195	$ 1,308,567	$ 368,700
Income not subject to tax	-	(24,493)	(17,365)
State tax, net of federal benefit	497,931	127,008	51,120
Effect of lower effective tax rates	-	(14,008)	-
Provision for income taxes	$ 5,628,126	$ 1,397,074	$ 402,455

As of December 31, 2005, the Company had net operating loss and IDC carry forwards for federal income tax reporting purposes of $8,770,000 which, if unused, will expire in 2022 and 2025. The Company is subject to Alternative Minimum Tax ("AMT") as a result of the deferred income that results from the regular tax treatment of intangible drilling costs. The AMT liability creates a deferred tax asset that can be used to offset any future tax liability from regular Federal income tax. The $401,109 minimum tax credit has an unlimited carryover period.

The net deferred tax liability consisted of the following:

December 31,	**2005**	**2004**
Deferred tax liabilities		
Property and equipment	11,102,307	2,163,239
Total deferred tax liabilities	11,102,307	2,163,239
Deferred tax assets		
Stock-based compensation	203,078	158,003
Minimum tax credit	401,109	-
Operating loss and IDC carryforwards	3,310,511	33,246
Total deferred tax assets	3,914,698	191,249
Net deferred income taxes	7,187,609	1,971,990

NOTE 11 SUBSEQUENT EVENTS (UNAUDITED)

Subsequent to December 31, 2005, the Company issued 120,800 shares of restricted common stock to reacquire the working interests and related rights in the Kansas properties discussed in Note 3.

Subsequent to December 31, 2005, the Company issued 6,200 shares of restricted common stock as a finders fee for the drilling rig the Company is in the process of acquiring.

Subsequent to December 31, 2005, the Company issued 29,126 warrants, exercisable at $10.30 per share. The warrants have an estimated life of 5 years from the date of issuance. The fair value of these warrants will be accounted for as other financing expense in 2006.

Subsequent to December 31, 2005, the Company has borrowed $3,500,000 on our credit facility described in Note 4.

NOTE 12 QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly financial information is presented in the following summary:

ARENA RESOURCES, INC.
NOTES TO FINANCIAL STATEMENTS

	2004			
	Three Months Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 1,200,400	$ 1,792,414	$ 2,516,970	$ 2,972,346
Operating Income	805,403	1,255,857	1,777,502	2,037,830
Net Income	262,397	520,662	803,496	865,097
Basic Net Income Per Share	$ 0.04	$ 0.07	$ 0.10	$ 0.10
Diluted Net Income Per Share	0.03	0.06	0.09	0.09

	2005			
	Three Months Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 3,914,735	$ 4,628,554	$ 7,937,785	$ 9,362,003
Operating Income	2,815,781	3,627,958	6,422,075	7,205,037
Net Income	1,286,700	1,715,100	3,443,999	3,014,884
Basic Net Income Per Share	$ 0.13	$ 0.17	$ 0.30	$ 0.23
Diluted Net Income Per Share	0.11	0.15	0.27	0.22

The net income per share information above will not match the income statement due to rounding.

NOTE 13 SIGNIFICANT FOURTH QUARTER ADJUSTMENTS

There were no material fourth quarter adjustments or accounting changes.

ARENA RESOURCES, INC.
SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES
(Unaudited)

Capitalized Costs Relating to Oil and Gas Producing Activities

December 31,	2005	2004	2003
Unproved oil and gas properties	$ 692,783	$ 388,581	$ 128,694
Proved oil and gas properties	69,077,903	34,068,557	8,334,706
Drilling advances on uncompleted projects	-	900,000	351,000
Advances on the acquisition of drilling rig	1,191,126	-	-
Support and office equipment	132,863	87,087	67,458
Total capitalized costs	71,094,675	35,444,225	8,881,858
Less accumulated depreciation and amortization	(4,346,628)	(1,565,124)	(559,229)
Net Capitalized Costs	$ 66,748,047	$ 33,879,101	$ 8,322,629

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31,	2005	2004	2003
Acquisition of proved properties	1,406,588	21,706,166	2,692,039
Acquisition of unproved properties (net of proceeds from property sale)	(160,454)	43,082	147,000
Exploration costs	464,656	216,805	326,410
Development costs	32,557,989	4,027,754	849,864
Total Costs Incurred	$ 34,268,779	$ 25,993,807	$ 4,015,313

Results of Operations from Oil and Gas Producing Activities The Company s results of operations from oil and gas producing activities exclude interest expense, accretion expense, gain from change in fair value of put options and the cumulative effect of change in accounting principle. Income taxes are based on statutory tax rates, reflecting allowable deductions.

For the Years Ended December 31,	2005	2004	2003
Oil and gas revenues	$ 25,843,077	$ 8,482,130	$ 3,665,477
Production costs	(3,832,487)	(1,975,835)	(1,149,136)
Production taxes	(1,939,739)	(629,703)	(269,563)
Depreciation, depletion, amortization and accretion	(2,884,089)	(1,011,602)	(360,282)
General and administrative (exclusive of corporate overhead)	(613,762)	(313,953)	(221,498)
Results of operations before income taxes	16,573,000	4,551,037	1,664,998
Provision for income taxes	(6,132,010)	(1,683,884)	(616,049)
Results of Oil and Gas Producing Operations	$ 10,440,990	$ 2,867,153	$ 1,048,949

Reserve Quantities Information The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the Company s reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company s reserves are located in the United States of America.

ARENA RESOURCES, INC.SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES(Unau

ARENA RESOURCES, INC.
SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES
(Unaudited)

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and methods.

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows.

For the Years Ended December 31,	**2005**		**2004**		**2003**	
	Oil (1)	**Gas (1)**	**Oil (1)**	**Gas (1)**	**Oil (1)**	**Gas (1)**
Proved Developed and Undeveloped Reserves						
Beginning of year	19,550,664	9,999,541	7,050,167	3,408,754	4,113,936	3,187,757
Purchases of minerals in place	882,460	377,179	8,764,087	6,431,437	3,175,357	570,924
Improved recovery and development	2,546,477	19,188,896	-	640,000	18,066	229,626
Production	(441,995)	(398,611)	(195,167)	(169,002)	(117,646)	(67,329)
Revision of previous estimate	2,329,583	2,815,074	3,931,577	(311,648)	(139,546)	(512,224)
End of year	24,867,189	31,982,079	19,550,664	9,999,541	7,050,167	3,408,754
Proved Developed at end of year	7,885,115	22,480,279	4,721,293	4,615,265	1,580,531	1,612,738

[1] Oil reserves are stated in barrels; gas reserves are stated in thousand cubic feet.

Standard Measure of Discounted Cash Flows

December 31,	**2005**	**2004**	**2003**
Future cash flows	$1,629,948,750	$ 814,346,791	$ 218,026,254
Future production costs	(281,685,991)	(171,518,828)	(64,157,199)
Future development costs	(95,765,594)	(61,975,106)	(13,609,384)
Future income taxes	(423,161,523)	(187,392,403)	(45,778,941)
Future net cash flows	829,335,642	393,460,454	94,480,730
10% annual discount for estimated timing of cash flows	(383,735,076)	(188,219,704)	(49,474,633)
Standardized Measure of Discounted Cash Flows	$ 445,600,566	$ 205,240,750	$ 45,006,097

ARENA RESOURCES, INC.
SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows

For the Years Ended December 31,	**2005**	**2004**	**2003**
Beginning of the year	$ 205,240,750	$ 45,006,097	$ 27,997,824
Purchase of minerals in place	33,405,120	142,824,938	21,333,720
Extensions, discoveries and improved recovery, less related costs	5,962,820	347,652	691,469
Development costs incurred during the year	189,832,736	5,387,638	320,102
Sales of oil and gas produced, net of production costs	(21,991,034)	(5,876,333)	(2,302,405)
Accretion of discount	28,467,073	4,882,064	3,012,793
Net changes in price and production costs	191,917,618	74,777,221	8,222,075
Net change in estimated future development costs	(36,307,702)	(3,187,159)	39,219
Revision of previous quantity estimates	87,175,031	42,149,044	(53,098)
Revision of estimated timing of cash flows	(111,387,288)	(27,509,967)	(5,468,732)
Net change in income taxes	(126,714,558)	(73,560,445)	(8,786,870)
End of the Year	$ 445,600,566	$ 205,240,750	$ 45,006,097