ARENA RESOURCES INC
Form 10KSB/A
July 27, 2004

United States Securities and Exchange Commission

Washington, D.C. 20549

Form 10-KSB/A

AMENDMENT NO. 1

(Mark One)

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

For the fiscal year ended December 31, 2003

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.
(Name of small business issuer 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

(Issuer 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

Check whether the issuer: (1) 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 **þ** No ¨

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

State issuer's revenues for its most recent fiscal year. $3,665,477

As of March 10, 2004, the aggregate market value of the common voting stock held by non-affiliates of the issuer, based upon the closing stock price of $6.70 per share, was approximately $31,710,410. As of March 10, 2004, the issuer had outstanding 7,163,097 shares of common stock ($0.001 par value).

Transitional Small Business Disclosure Format (check one): Yes ¨ No **þ**

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Forward Looking Statements

All statements, other than statements of historical fact included in this Annual Report on Form 10-KSB (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 and similar expressions are 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 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.

We are engaged in oil and natural gas acquisition, exploration, development and production, with activities currently in Oklahoma, Texas, New Mexico and Kansas. Our intermediate-term focus is on pursuing acquisition of oil and gas properties that provide immediate cash flow, as well as opportunities for further development. Our intent is to minimize our near-term risks, and to increase exploration activities once we have established a larger production base.

Business Development

Since our inception in August 2000, we have built our asset base and achieved growth primarily through property acquisitions. Finding properties that are suitable for our intermediate-term plans can sometimes be difficult, since we look for properties with development potential as well as existing cash flow. We believe the key to being successful is in undertaking thorough due diligence of each property we acquire or consider for acquisition.

From our inception through December 31, 2003, we have increased our proved reserves to approximately 7.6 million Boe (barrel of oil equivalent), through the acquisition of interests in 10 leases, which have net revenue interests ranging from 24.5% to 81.32%. As of December 31, 2003, our estimated proved reserves had a pre-tax PV10 (present value of future net revenues before income taxes discounted at 10%) of approximately $67 million. We spent approximately $6.26 million on acquisitions and capital projects during 2002 and 2003.

We have a portfolio of oil and natural gas reserves, with approximately 92% of our proved reserves consisting of oil and approximately 8% consisting of natural gas. Approximately 21.5% of our proved reserves are classified as proved developed producing, or PDP. Approximately 5% of our proved reserves are classified as proved developed non-producing, or PDNP, and approximately 73.5% 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 f or 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 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 2003, three customers were responsible for generating 81% or more of our total oil and natural gas sales. These three customers were Plains Marketing, L.P., accounting for approximately 51% of total sales, Sun Oil Company, accounting for approximately 19% of total sales and Navajo Refining Company, accounting for approximately 11% of total sales. However, we believe that the loss of any one of these customers would not materially impact our business, becaus e 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 prorationing 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 uncon trolled 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, 2003, we had seven full-time employees, including one petroleum engineer. 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 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, 2003, our proved reserves have grown to 7,618,283 Boe, at an average acquisition/drilling cost of $1.08 per Boe. As of December 31, 2003, our estimated proved reserves had a pre-tax PV10 value of approximately $67 million, approximately 46% of which came from properties located in Oklahoma, approximately 37% from our properties in New Mexico and approximately 14% from our properties in Texas. We spent approximately $7.28 million on capital projects during 2002 and 2003, including approximately $5.13 million for the acquisition of 7.6 million Boe of proved reserves (estimated as of the date of acquisition). We expect to further deve lop these properties through additional drilling. We have budgeted approximately $10 million for capital expenditures in 2004, all of which is targeted for the acquisition of additional reserves. We anticipate that we will soon seek additional capital as a source of a portion of the funding for this acquisition strategy. Other funds to finance potential acquisitions will come from cash flow from operations and, if necessary, from drawing on our credit facility. We believe that our acquisition expertise, together with our operating experience and efficient cost structure, provides us with the potential to continue our growth.

We have a portfolio of oil and natural gas reserves, with approximately 92% of our proved reserves consisting of oil and approximately 8% consisting of natural gas. Approximately 21.5% of our proved reserves are classified as proved developed producing properties. Approximately 5% of our proved reserves are classified as proved developed nonproducing, and approximately 73.5% are classified as proved undeveloped.

The following table summarizes our total net proved reserves and pre-tax PV10 value as of December 31, 2003.

Proved Developed and Undeveloped Reserves

Geographic Area	Oil (Bbl)	Natural Gas (Mcf)	Total (Boe)	Pre-Tax PV10 Value
Oklahoma	3,465,351	658,484	3,575,099	$ 32,623,882
Texas	860,588	1,107,544	1,045,179	11,557,113
New Mexico	2,724,228	394,484	2,789,975	20,820,341
Kansas	--	1,248,242	208,040	1,583,620
Total	7,050,167	3,408,754	7,618,283	$ 66,584,956

Proved Reserves

Our 7,618,283 Boe of proved reserves, which consist of approximately 92% oil and 8% natural gas, are summarized below as of December 31, 2003, on a net pre-tax PV10 value basis. Our reserve estimates have not been filed with any Federal authority or agency (other than the SEC).

As of December 31, 2003, our Oklahoma proved reserves had a net pre-tax PV10 value of $32.6 million and our proved reserves in New Mexico had a net pre-tax PV10 value of $20.8 million and our proved reserves in Texas had a net pre-tax PV10 value of $11.6 million. Collectively, these three areas represented approximately $65 million, or 98%, of our total proved reserve net pre-tax PV10 value of $67 million as of December 31, 2003.

As of December 31, 2003, approximately 21.5% of the 7.6 million Boe of proved reserves have been classified as proved developed producing, or PDP . Proved developed non-producing, or PDNP , and proved undeveloped, or PUD reserves constitute 5% and 73.5%, respectively, of the proved reserves as of December 31, 2003.

Total proved reserves had a net pre-tax PV10 value as of December 31, 2003 of approximately $67 million, 20% or $13.4 million of which is associated with the PDP reserves. An additional $1,781,,000 is associated with the PDNP reserves ($15.2 million for total proved developed reserves, or 22.8% of total proved reserves pre-tax PV10 value) and $51.4 million is associated with PUD reserves.

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Our proved reserves as of December 31, 2003 are summarized in the table below.

	Oil (Bbl)	**Natural Gas (Mcf)**	**Total (Boe)**	**% of Total Proved**	**Pre-tax PV10 (In thousands)**	**Future Capital Expenditures (In thousands)**
Oklahoma:						
PDP	736,427	658,484	846,174	11 %	$ 7,707	$ --
PDNP	--	--	--	0 %	--	--
PUD	2,728,924	--	2,728,915	36 %	24,917	5,275
Total Proved:	3,465,351	658,484	3,575,089	47 %	$ 32,624	$ 5,275
Texas:						
PDP	349,598	136,747	372,389	5 %	$ 3,235	$ --
PDNP	--	--	--	0 %	--	--
PUD	510,990	970,797	672,790	9 %	8,322	2,200
Total Proved:	860,588	1,107,544	1,045,179	14 %	$ 11,557	$ 2,200

New Mexico:								
PDP	494,496	209,047	529,337	7 %	$	3,407	$	--
PDNP	--	--	--	0 %		--		--
PUD	2,229,732	185,437	2,260,638	30 %		17,413		6,014
Total Proved:	2,724,228	394,484	2,789,975	37 %	$	20,820	$	6,014
Kansas:								
PDP	--	--	--	0 %	$	--	$	--
PDNP	--	608,460	101,410	1 %		852		--
PUD	--	639,782	106,630	1 %		732		120
Total Proved:	--	1,248,242	208,040	2 %	$	1,584	$	120
Total:								
PDP	1,580,521	1,004,278	1,747,901	23 %	$	14,350	$	--
PDNP	--	608,460	101,410	1 %		852		--
PUD	5,469,646	1,796,016	5,768,972	76 %		51,384		13,609
Total Proved:	7,050,167	3,408,754	7,618,283	100 %	$	66,585	$	13,609

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Production

Our estimated average daily production for the month of December, 2003, is summarized below. These tables indicate the percentage of our estimated December 2003 average daily production of 420 Boe/d attributable to each state and to oil versus natural gas production.

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Average Daily Production (December 2003): 420 Boe/d

State	Average Daily Production	Oil	Natural Gas
Oklahoma	49.15 %	45.65 %	3.50 %
Texas	24.62 %	23.84 %	0.78 %
New Mexico	26.23 %	23.37 %	2.86 %
Kansas	-- %	-- %	-- %
Total	100 %	92.86 %	7.14 %

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Summary of Oil and Natural Gas Properties and Projects

Significant Oklahoma Operations

Casey Lease Muskogee County, Oklahoma. The Casey Lease originally consisted of a 40% working interest contributed by our two principal shareholders. We subsequently acquired additional interests in this lease, so that presently we have a 94% working interest, and an approximately 74.48% net revenue interest in the well on this property. 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.

In May 2001, we acquired an additional 30% working interest in the lease from a group of interest holders represented by Petro Consultants, Inc. The additional working interest was valued at $300,000 and was acquired by the issuance of 80,000 shares of common stock valued at $1.75 per share totaling $140,000, the assumption of a $50,000 obligation of the seller and the issuance of a note payable for $110,000. This note was subsequently settled through cash payments of $45,000 and the issuance of an additional 37,143 shares of common stock valued at $1.75 per share totaling $65,000. The $50,000 liability assumed from the seller related to the seller s previous obligation to the operator of the properties and has been paid.

In October 2001, we acquired an additional 24% working interest and a 2½% overriding royalty interest in the Casey lease from a group of interest holders represented by Petro Consultants, Inc. The acquired interests were valued at $266,250 and were purchased by the issuance of 81,857 shares of common stock valued at $1.75 per share totaling $143,250, a cash payment of $90,000 and the issuance of a note payable for $33,000. The note was subsequently paid.

The remaining working interest in the Casey lease is owned by an unaffiliated party. This lease consists of approximately 160 acres. In December 2003 we temporarily shut-in this gas well. We anticipate that we will attempt to recomplete this well in another zone in the future, to bring it back into production. The Casey lease will expire in December 2004 if not then held by production.

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 seven producing wells. We believe up to five additional locations may be suitable for drilling, 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, with a possibility for two additional wells, 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 five producing wells, and we believe there are up to three additional drilling locations on these leases. The Hanes lease contains approximately 640 acres and four producing wells, with a possibility of up to two additional wells, 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 Texas Operations

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 million cost thereof) is included as PUD in our rese rve report. This lease consists of approximately 2,073 acres of which 1,697 acres are held by production and the remaining 376 acres expire July 30, 2004.

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.

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 10 producing wells. We believe it can support up to four additional wells, which are included in our estimate of PUD. This lease is held by production.

Significant New Mexico Operations

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 43 producing wells on this lease, and we believe it can support six to eight possible infill wells (additional wells within the spacing requirements of the unit), as well as some untested formations in shallow sand. 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 21 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 currently anticipate it can support up to 23 additional wells, 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. 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 must be submitted to the Bureau of Land Management and are usually granted within ninety days of application submittal. The construction of the water line should require approximately thirty days at a cost of $250,000. The permit application will be submitted in the first quarter 2005 with construction slated for the summer of 2005. The development of the North Benson Queen Unit waterflood is scheduled for 2006 at estimated costs of $5,732,000.

Significant Kansas Operations

Auntie Em Lease Haskell County, Kansas. This lease consists of approximately 800 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).

We successfully drilled one well at a cost of approximately $127,000 and thus will have reached payout when we recover this amount from production. However, the well is currently shut-in pending a pipeline connection. 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.

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 Calvin R. Hullum, Jr., an unaffiliated party, for a cash payment of $60,000. During August 2003 we drilled one well on this acreage, which was unsuccessful and was plugged and abandoned. This lease will expire in April 2006 if not then held by production.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2003 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**
Oklahoma	5,689	4,222	--	--	5,689	4,222
Texas	3,464	2,773	376	301	3,840	3,074
New Mexico	4,040	2,661	--	--	4,040	2,661
Kansas	160	128	2,200	1,773	2,360	1,901
Total	13,353	9,784	2,576	2,074	15,929	11,858

Production History

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

	Year Ended December 31,		
	2001	2002	2003
Oil production (Bbls)	12,895	58,717	117,646
Natural gas production (Mcf)	4,776	46,819	67,329
Total production (Boe)	13,691	67,520	128,868
Daily production (Boe/d)	38	185	352
Average sales prices:			
Oil (per Bbl)	$ 22.36	$ 26.09	$ 29.06
Natural gas (per Mcf)	1.79	2.67	3.67
Total (per Boe)	21.69	24.91	28.44
Average production cost (per Boe)	$ 7.81	$ 8.94	$ 8.92

In December 2003, we temporarily shut-in a well that accounted for approximately 11% of our natural gas production in 2003. The remaining natural gas production comes from our wells that are primarily oil producers.

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Productive Wells

The following table presents our ownership at December 31, 2003, in productive oil and natural gas wells by region (a net well is our percentage ownership of a gross well).

Oil Wells	Natural Gas	Total Wells

	Wells [1]					
	Gross	Net	Gross	Net	Gross	Net
Oklahoma	23	16.53	--	--	23	16.53
Texas	25	20.00	--	--	25	20.00
New Mexico	64	40.49	--	--	64	40.49
Kansas	--	--	--	--	--	--
Total	112	77.02	--	--	112	77.02

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(1) We had one producing natural gas well until December of 2003, when it was temporarily shut-in. Our remaining production of natural gas comes from wells which we classify as oil wells, due to the fact that the principal production from such wells is oil.

Drilling Activity

In the past three years we have focused our attention primarily on property acquisitions, and not on development of our properties. However, in 2001 we participated in the drilling of two gross wells in Oklahoma (each a 0.7 net well). One well was completed as a producing well, and the other was plugged and abandoned as a dry hole. In 2002 we participated in the drilling of one gross well (0.8 net well) in Kansas, which was completed as a producing well. In 2003 we participated in drilling one gross well (0.8 net well) in Kansas, which was plugged and abandoned as a dry hole.

Cost Information

We conduct our oil and natural gas activities entirely in the United States. Our average production costs, per Boe, were $7.81 in 2001, $8.94 in 2002 and $8.92 in 2003. Net capitalized costs related to our oil and natural gas producing activities are shown below.

	Years Ended December 31,		
	2001	2002	2003
Proved oil and natural gas properties	$ 1,584,645	$ 3,238,985	$ 2,890,413

Unproved oil and natural gas properties	--	--	128,694
Accumulated depreciation, depletion and amortization	(44,148)	(127,847)	(338,157)
Oil and natural gas properties, net	$ 1,540,497	$ 3,111,138	$ 2,680,950

The total capitalized costs identified above ($7,842,737), together with $61,174 of capitalized costs in 2000 and $559,489 capitalized as part of recognizing the long-lived asset retirement obligation required by FASB 143, results in total oil and gas properties subject to amortization of $8,463,400 at December 31, 2003.

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, except for the Dodson Lease in Montague County, Texas, which was based on our internal estimates, all 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, 2000	--	478,263
Purchases of minerals in place	490,333	1,636,959
Extensions and discoveries	--	843,512
Production	(12,895)	(4,776)
Revisions of previous estimates	17,385	7,229
Balance, December 31, 2001	494,823	2,960,373
Purchases of minerals in place	3,597,156	1,676,706
Extensions and discoveries	--	--

Production	(58,717)	(46,819)
Revisions of previous estimates	80,674	(1,402,503)
Balance, December 31, 2002	4,113,937	3,187,757
Purchases of minerals in place	3,175.357	570,924
Extensions and discoveries	18,066	229,626
Production	(117,646)	(67,329)
Revisions of previous estimates	(139,546)	(512,224)
Balance, December 31, 2003	7,050,167	3,408,754

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Our proved oil and natural gas reserves are shown below.

	As of December 31,		
	2001	**2002**	**2003**
Oil (Bbls):			
Developed	142,371	750,464	1,580,521
Undeveloped	352,452	3,363,473	5,469,646
Total	494,823	4,113,937	7,050,167
Natural Gas (Mcf):			
Developed	1,038,564	1,160,639	1,612,738
Undeveloped	1,921,809	2,027,118	1,796,016

Total	2,960,373	3,187,757	3,408,754
Total (Boe):			
Developed	315,465	943,904	1,849,311
Undeveloped	672,754	4,451,790	5,768,972
Total	988,219	5,395,694	7,618,283

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.

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

December 31,

	2002	2003
Future cash inflows	$ 109,145,883	$ 218,026,254
Future production costs	(28,850,909)	(64,157,199)
Future development costs	(6,218,000)	(13,609,384)
Future income tax expense	(23,701,042)	(45,778,941)
Future net cash flows	50,375,932	94,480,730
10% annual discount for estimated timing of cash flows	(22,378,108)	(49,474,633)
Standardized measure of discounted future net cash flows	$ 27,997,824	$ 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,	
	2002	2003
Beginning of the year	$ 5,203,372	$ 27,997,824
Purchase of minerals in place	34,477,311	21,333,720
Extensions, discoveries and improved recovery, less related costs	--	691,469
Development costs incurred during the year	215,433	320,102
Sales of oil and gas produced, net of production costs	(1,057,366)	(2,302,405)
Accretion of discount	3,525,683	3,012,793
Net changes in prices and production costs	6,456,827	8,222,075
Net change in estimated future development costs	(142,491)	39,219
Revisions of previous quantity estimates	(2,497,666)	(53,098)
Revision in estimated timing of cash flows	--	(5,468,732)
Net change in income taxes	(18,183,279)	(8,786,869)
End of the Year	$ 27,997,824	$ 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 13,353 gross (9,784 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, 2003, we owned interests in approximately 2,576 gross undeveloped acres (2,074 net). While our short-term business strategy is to continue to acquire properties with both existing cash flow from production and future development potential, our intermediate and long-term business plan includes the further exploitation of our properties through additional drilling activities. After we have expanded our portfolio of producing properties, we anticipate financing th ese future exploitation activities from the cash flow generated by production. Our current strategy is to attempt to acquire approximately $8 million to $10 million in additional properties to achieve critical mass . We believe the cash flow from existing production on our current properties and these new acquisitions will enable us to undertake the further development and exploitation in a prudent manner. See Proposed Acquisition Activity below.

We anticipate that we will soon seek additional capital as a source of a portion of the funding of this acquisition strategy. If we are not successful in raising the anticipated funds in this manner, we may not be able to secure sufficient capital (from borrowings or otherwise) to acquire $8 million to $10 million in additional properties. This could lead us to alter our current business strategy (focusing on acquisitions), and instead result in our determination that we should concentrate on the exploitation and further development of our existing properties. Such a determination could also significantly alter our business plan regarding the source of financing for such development activities (because our cash flow from our current production would not be sufficient to undertake the level of development we currently anticipate). In s uch event, it is possible that we would have to significantly decrease the level of exploration activities that we would otherwise undertake.

Pursuing Profitable Acquisitions. We have pursued and intend to continue to pursue 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. From August 2000 through December 31, 2003, we acquired 10 leases at an aggregate acquisition and enhancement cost of approximately $7.9 million, representing approximately 7.6 million Boe of proved reserves (at an average cost of $1.08 per Boe).

Focusing on High Return Operated Properties. We have historically acquired operated properties that meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring properties we can operate so that we can better control the timing and implementation of capital spending. We intend to continue to acquire both operated and non-operated interests to the extent they meet our return criteria and further our growth strategy.

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, 2003, our lease operating expense per Boe averaged $8.92 and general and administrative costs averaged $4.33 per Boe produced.

Other Properties and Commitments

We currently lease our principal executive offices in Tulsa, Oklahoma. The lease is for approximately 2,352 square feet of office space, at an annual rental of $20,400. The lease expires on December 31, 2005. The current facilities are believed adequate for our current operations.

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Item 3:

Legal Proceedings

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:

Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of security holders, through solicitation of proxies or otherwise, during the period from October 1, 2003, through December 31, 2003

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 two years.

Period	High Sale or Bid	Low Sale or Bid
1st Quarter 2002	$2.65	$2.40
2nd Quarter 2002	4.00	2.40
3rd Quarter 2002	4.25	3.99
4th Quarter 2002	4.60	4.00
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 (through March 12)	$6.80	$5.85

Record Holders

As of January 20, 2004, there are approximately 647 holders of record of our common stock. Approximately 34%, or 2,430,200 shares of the 7,163,097 shares issued and outstanding as of such date are held by management or affiliated parties.

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Dividend Policy

We have not paid any dividends on our common stock during the last two 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. Information regarding this plan and the options that have been granted under this plan may be found in the Annual Report under Part III, Items 10 and 11.

Recent Sales of Unregistered Securities

In October 2003, we issued 25,000 shares of common stock valued at $5.64 per share, or $141,000, as compensation to a consultant utilized in connection with our acquisition of the North Benson Queen Unit in Eddy County, New Mexico. The 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 person 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 t he 1933 Act. There was no underwriter involved in this transaction.

In October 2003, we also issued an additional 7,000 shares of common stock valued at $5.65 per share, or $39,550, as compensation to a consultant utilized in connection with our acquisition of the West San Andres Unit in Yoakum County, Texas. The 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 person 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 registrat ion under the 1933 Act. There was no underwriter involved in this transaction.

During October 2003, we issued 8,000 shares of our common stock upon the exercise of warrants, at $1.75 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 person 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 this transaction.

Issuer Repurchases

We did not make any repurchases of our equity securities during the quarter ending December 31, 2003.

Item 6:

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 three years, we have emphasized the acquisition of properties that provided current production and significant upside potential through further development.

We have increased our reserves significantly by investing $4 million in acquisitions and enhancements in 2003, following total capital expenditures of approximately $3.2 million in 2002 and approximately $1.6 million in 2001.

Our capital budget for 2004 is approximately $10 million, which will be utilized to acquire properties. We anticipate that we will soon seek additional capital as a source of a portion of this capital budget. The remainder of the funds for our acquisition program will come from a portion of our anticipated cash flow from operations and, possibly, a portion of the amount we can draw under our available credit facility. We anticipate this amount will be used almost exclusively for the acquisition of additional reserves in 2004. However, our strategy could change if we are unable to find suitable properties at a price we believe satisfies our acquisition strategy, or in the event we decide not to seek additional capital (or are unsuccessful in such endeavor)and we are unable to obtain alternate sources of financing for such acquisition activit ies. In such an event, it is possible that we could deviate from our current business plan, and begin the exploitation and further development of our existing properties by spending a portion of our capital budget on drilling activities. In this event, the amount of development activities that we would undertake could be significantly less than the development activities that we anticipate conducting assuming this offering (and the related acquisition program) is successful.

Our strategy is to acquire producing properties with additional development, exploitation and exploration potential. Therefore, 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 some instances, we have been able to acquire non-operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. 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 short- to intermediate-term business plan has been to increase our base of proven reserves until we have acquired a sufficient base 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 may initiate our development activities in the more immediate future, especially if it appears the current rise in oil and natural gas prices is expected to continue for a reasonable period.

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:

	Years Ended December 31,		
	2001	**2002**	**2003**
Net production:			
Oil (Bbls)	12,895	59,468	117,646
Natural gas (Mcf)	4,776	47,985	65,417

Net sales:						
Oil	$	302,424	$	1,532,045	$	3,418,480
Natural gas		9,309		124,992		246,997
Average sales price:						
Oil (per Bbl)	$	22.36	$	25.76	$	29.06
Natural gas (per Mcf)		1.79		2.60		3.78
Production costs and expenses:						
Lease operating expenses	$	106,927	$	594,863	$	1,149,136
Production taxes		14,797		117,164		269,563
Depreciation, depletion and amortization expense		44,148		128,847		338,157
General and administrative expenses		127,696		248,018		557,576

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $2 million to $3.66 million in 2003. Oil sales increased $1.89 million and natural gas sales increased $122,000. The oil sales increase was caused by a sales volume increase of 58,929 barrels in 2003, and a 11% increase in the average realized per barrel oil price from $26.09 in 2002 to $29.06 in 2003. The natural gas sales increase was caused by a sales volume increase of 20,510 Mcf in 2003 and a 37% increase in the average realized natural gas price per Mcf from $2.67 in 2002 to $3.67 in 2003. The volume increase for crude oil and natural gas primarily resulted from $3 million of capital expenditures during 2003.

Lease operating expenses. Our lease operating expenses increased from $594,863 or $8.82 per Boe in 2002 to $1,149,136 or $8.92 per Boe in 2003. This increase was a result of higher operating costs on properties acquired in 2003. While it is possible that this increase will continue in the future as we acquire additional properties, because each property is individual in its characteristics, at this time, apart from normal increases associated with inflation in general, we cannot specifically identify this increase to be a trend.

Production taxes. Production taxes as a percentage of oil and natural gas sales were 7% during 2002 and remained steady at 7% in 2003. 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

$210,310 to $338,157 in 2003. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $1.92 per Boe during 2002 to $2.63 per Boe during 2003. 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 $309,558 to $557,576 during 2003. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer our growth (specifically, the addition of our in-house engineer), listing fees of $56,625 paid to the American Stock Exchange, $61,280 in fees paid to a stock research analyst, fees related to obtaining our credit facility and letters of credit and directors fees.

Interest expense. Interest expense increased $22,875 to $38,798 in 2003. The increase was due to our debt being outstanding for the entire year in 2003, as opposed to being outstanding for a partial year in 2002.

Income tax expense. Our effective tax rate was 37% during 2003 and 32% during 2002. The effective rate was higher during 2003 due to having more income subject to income tax, higher state income tax and no benefit of operating loss carry forwards in 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 l iability 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 $402,694 for 2002 before preferred stock dividends, to $824,322 for 2003. 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 lease operating expense, tax expense and general and administrative expenses due to our growth.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Oil and natural gas sales. Oil and natural gas sales revenue increased approximately $1.35 million to $1.66 million in 2002. Oil sales increased $1.2 million and natural gas sales increased $116,000. The oil sales increase was caused by a sales volume increase of 45,822 barrels in 2002 and a 15% increase in the average realized oil price from $22.36 in 2001 to $26.09 in 2002. The natural gas sales increase was caused by a sales volume increase of 42,043 Mcf in 2002 and a 45% increase in the average realized natural gas price from $1.79 per Mcf in 2001 to $2.67 in 2002.The volume increase for oil and natural gas was due to $4.8 million of capital expenditures during 2001 and 2002.

Lease operating expenses. Our lease operating expenses per Boe increased from $106,927 or $7.81 per Boe in 2001 to $594,863 or $8.94 per Boe in 2002. The increase resulted primarily from higher operating costs associated with properties acquired in 2002.

Production taxes. Production taxes as a percentage of oil and natural gas sales were 7% in 2002 and 5% in 2001. The increase in the effective rate resulted from increased operations in the state of Oklahoma, where production tax rates are higher.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased by $83,699 from $44,148 in 2001 to $127,847 in 2002. The increase was a result of increasing sales volumes, though partially offset by a decreased depletion rate per Boe from $3.22 in 2001 to $1.92 in 2002.

General and administrative expenses. General and administrative expenses increased 94% or $120,322 from $127,696 (which includes $8,000 in non-cash services contributed by majority shareholders) in 2001 to $248,018 in 2002. This increase was related to increases in compensation expense associated with increased personnel (specifically, the hiring of an administrative assistant), our executive officers receiving a salary for the entire year in 2002, as opposed to four months in 2001 (since our Chairman and President voluntarily deferred receiving compensation until September 2001, following our initial public offering, and our chief financial officer was hired in September of 2001).

Interest expense. Interest expense increased to $15,923 in 2002 from $0 in 2001. The increase was due to higher average debt levels in 2002 to fund our growth.

Income tax expense. Our effective tax rate before tax credits was 32% in 2002 compared to 0% in 2001, when we had no taxable income.

Net income (loss). Our net loss attributable to common stockholders increased from $(44,927) in 2001 to $(395,324) in 2002. The primary reasons were a $734,496 increase in preferred stock dividends and an $811,749 increase in expenses, offset by a $1.3 million increase in revenues. The increase in preferred stock dividends was caused by more of our preferred stock being outstanding for a longer part of the year. The expense increase was caused by higher operating expenses from additional leases, higher production tax and depreciation, depletion and amortization from higher production, and higher general and administrative expense related to increases in compensation expenses associated with increased personnel to administer our growth. The revenue increase was caused by higher production volumes and an increase in oil and natur al gas prices between years 2001 and 2002.

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, and private equity offerings of our stock and warrants.

Credit Facility. In February 2003 we established a $10,000,000 revolving credit facility with an initial borrowing base of $2,000,000. In December 2003, we entered into an agreement that increased the facility to $20,000,000, with an increased borrowing base of $4,000,000. The borrowing base is based on the collateral value of proved reserves and is subject to redetermination semiannually, based on both commodity prices of oil and natural gas, and our estimated proved reserves. The credit facility, as amended in December 2003, provides for interest at a floating rate equal to the JP Morgan Chase prime rate plus 1%, with interest payable monthly, and annual fees of ¼ of 1% of the unused portion of the borrowing base. Any amounts borrowed will be due December 31, 2005. The credit facility has covenants that restrict th e payment of cash dividends, borrowings, sale of assets, loans to others, investments, merger activity, liens and certain other transactions without the prior consent of the lender. The facility also requires us to maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense, a current ratio of 1-to-1, and a tangible net worth of $6 million. The credit agreement is secured by a first lien on substantially all of our assets. In addition, our loans from two officers which were outstanding prior to this facility are subordinated to the debt evidenced by the credit facility. As of December 31, 2003, no amounts are owed under this credit facility.

Cash Flows. Our primary sources of cash have been cash flows from operations, and equity offerings. During the three years ended December 31, 2003, we generated $2,307,721 from operating activities, financed $5,393,954 through proceeds from the sale of stock and warrants, and $400,000 from debt obligations owed to two officers, for a total of $8,101,675. We primarily used this cash generation to fund our capital expenditures aggregating $8,868,331 over the three years. At December 31, 2003, we had $1,076,676 of cash and $1,268,888 of working capital compared to December 31, 2002 when our cash position was $796,915 and working capital was $937,120.

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for 2004 are $10,000,000 for acquisitions to expand our property base. We expect to fund these expenditures from cash on hand, additional capital that we anticipate seeking, internally generated cash flow during the year 2004, and from borrowings under our credit facility, if required. In the event we are not successful in raising the anticipated funds from our proposed securities offering, we nevertheless believe capital expenditures of approximately $10,000,000 could be financed through cash on hand, additional borrowings under our credit facility or otherwise (including financing on a property-by-property basis). The level of capital expenditures is largely discretionary, and the amount of funds devoted to any particular activity may incr ease or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among others.

If we are not successful in obtaining funding from the sources above to finance our acquisition program, we anticipate that we would instead seek to acquire a smaller number of producing properties and/or initiate further development of our existing properties. This development would be funded by internally generated cash flow and from borrowings under our credit facility. If the funding is limited to these sources, our anticipated development activities would be more limited than anticipated under our present business plan (which calls for such activities to be substantially funded from a broader base of producing properties acquired through our acquisition program).

Schedule of Contractual Obligations. The following table summarizes our future estimated principal and minimum debt and lease payments for periods subsequent to December 31, 2003.

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Year		Long-Term Debt		Lease Obligation		Total Cash Obligation
2004	$	--	$	20,400	$	20,400
2005	$	400,000	$	20,400	$	420,400
2006	$	--	$	--	$	--
Total	$	400,000	$	40,800	$	440,800

Off-Balance Sheet Financing Arrangements

As of December 31, 2003 we had no off-balance sheet financing arrangements.

New Accounting Policies

In June 2001, the Financial Accounting Standards Board, or the FASB, issued Statement of Financial Accounting Standards, or SFAS, No. 141, Business Combinations, which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice of amortizing goodwill and indefinite-lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. The adoption of SFAS No. 142 has had no effect on our financial statements, as the Company has not recognized an y intangible assets, since the fair market value of all assets acquired has exceeded the purchase price.

In June 2002, the FASB issued SFAS No. 146, Accounting for Costs Associates with Exit or Disposal Activities. This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. We do not believe that adoption of this Statement will have a material impact on our financial statements.

In November 2002, the FASB issued Interpretation No. 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. The interpretation requires that a liability measured at fair value be recognized for guarantees. The Company has not provided any guarantees and therefore the adoption of the interpretation had no impact on the Company s financial statements.

In December 2002, the FASB issued SFAS No. 148, *Accounting for Stock-Based Compensation-Transition and Disclosure*. Under the requirements of this statement, the Company has disclosed the effects on reported net income of the Company s accounting policy with respect to stock-based employee compensation. See Note 7 to our financial statements included as a part of this Annual Report.

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).

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 August 2002. 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 polici es 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, except for the Dodson Lease which is based on our internal estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and 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 a ssumptions 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

We have not experienced any significant increased costs during 2002 and 2003 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. 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. While we do not currently expect business costs to materially increase, continued high prices for oil and natural gas could result in increases in the cost of material, services and personnel.

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

In the event we draw under our current credit facility that has a floating interest rate, interest rate changes will impact future results of operations and cash flows.

Item 7:

Financial Statements

The financial statements and supplementary data required by this item are included at page 40.

Item 8:

Changes in and Disagreements with Accountants And Accounting and Financial Disclosure

None.

Item 8A:

Controls and Procedures

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submits 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. Based upon their evaluation of those controls and procedures performed within 90 days of the filing date of this report, the chief executive officer and the principal financial officer of the Company concluded that our disclosure controls and procedures were adequate.

We made no significant changes in its internal controls or in other factors that could significantly affect these controls subsequent to the date of the evaluation of those controls by the chief executive officer and principal financial officer.

PART III

Item 9:

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, 2003:

Name	Age	Position
Lloyd T. Rochford	57	President and Chief Executive Officer and Director
Stanley M. McCabe	71	Chairman of the Board of Directors, Secretary and Treasurer
William R. Broaddrick	26	Vice President and Chief Financial Officer
Charles M. Crawford	51	Director
Chris V. Kemendo, Jr.	82	Director
Clayton E. Woodrum	63	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 July 2003, with the exception of Mr. Woodrum. Mr. Woodrum was appointed in August 2003 by the Board of Directors to fill a vacancy created upon the resignation of a director.

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.

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

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

Mr. Rochford, 57, 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 is 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. Since July, 1997, Mr. Rochford has primarily devoted his time and efforts to individual oil and gas acquisition and development prior to his commitment to participate in Arena Resources. 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, 71, 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. Since January, 1997, Mr. McCabe has been involved as an independent investor and developer of oil and natural gas properties. 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, 26, 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, 51, 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, 82, has from 1989 to present acted as an independent financial business and accounting consultant to various clients. Mr. Kemendo is currently the Chairman of our audit committee. 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, 63, is a Certified Public Accountant and has, from 1984 to present, been a principal shareholder in the accounting firm of Woodrum, Kemendo & Cuite, P.C., and has been an owner of Computer Data Litigation Services, LLC and First Capital Management, LLC. 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 & Cuite, P.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 2004 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. Kemendo acting as the chairman. Our board of directors has determined that each member of the audit committee qualifies as an audit committee financial expert und er 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.

We currently do not have a separate compensation committee. However, 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 a majority of the independent directors serving on the Board. Compensation for all other officers is determined, or recommended to the Board for determination, by a majority of the independent directors.

We currently do not have a nominating committee.

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. No director receives a salary as a director.

Compensation Committee Interlocks and Insider Participation

As noted above, we currently do not have a compensation committee. As a result, the majority of our independent members of our board, consisting of Messrs. Crawford, Kemendo and Woodrum, are responsible for fixing the compensation to be paid to our executive officers. 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

The Company has adopted a code of ethics that applies to its 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 10:

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*	2001	$24,500	--	--
	2002	$36,000	--	--
	2003	$36,000	--	$229,742

Stanley M. McCabe				
Chairman of the Board	2001	$24,500	--	--
	2002	$36,000	--	--
	2003	$36,000	--	$229,742
William R. Broaddrick				
Vice President, Chief Financial Officer	2001	$16,334	$3,000	--
	2002	$45,000	$6,000	--
	2003	$47,927	--	$459,484

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(1) Mr. Broaddrick s salary for 2003 reflects a raise that occurred in mid-year to increase his annual salary to $50,000. There are no current plans to change any officers salary from their level at December 31, 2003.

(2) The fair value of the options is 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 at December 31, 2003 was 4.2 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. 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 1,000,000 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. All of the shares available for grant under the plan have been reserved for issuance pursuant to options granted during 2003, as shown in the table below.

Name	Number of Securities Underlying Options/SARs Granted	Percent of Total Options/SARs Granted to Employees in Fiscal Year	Exercise Of Base Price ($/Sh)	Market Price per Share on Date of Grant	Expiration Date
Lloyd T. Rochford	125,000	12.5%	$3.70	$4.35	10/1/08
Stanley M. McCabe	125,000	12.5%	$3.70	$4.35	10/1/08
William R. Broaddrick	250,000	25.0%	$3.70	$4.35	10/1/08
Charles M. Crawford	50,000	5.0%	$3.70	$4.35	10/1/08
Chris V. Kemendo, Jr.	50,000	5.0%	$3.70	$4.35	10/1/08
Clayton E. Woodrum	50,000	5.0%	$4.80	$5.64	02/12/09
Phillip W. Terry	250,000	25.0%	$3.70	$4.35	10/1/08
Raymond H. Estep	100,000	10.0%	$3.70	$4.35	10/1/08

Each of the options identified above vests at the rate of 20% each year over five years beginning one year from the date of grant. All of the options identified above, with the exception of options granted to Mr. Woodrum, were issued on April 1, 2003. Mr. Woodrum s options were granted on August 12, 2003. Therefore, no options were capable of being exercised during our fiscal year ending December 31, 2003. The exercise price of each option was 85% of the closing market price of our common stock on the date the option was issued. The options for 50,000 shares granted to Mr. Woodrum, were originally granted to a former director on April 1, 2003; however, upon such director s resignation, in accordance with the terms of the options, those options were forfeited. Mr. Woodrum s options were granted in connection with his appointment to fil l the vacant board position.

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, 2003 and the exercise price of the options.

Name	Shares Acquired on Exercise	Value Realized ($)	Number of Unexercised Securities Underlying Options/SARs at FY-End	Value of Unexercisable In-The-Money Options/SARs at FY-End ($)

			(#) Exercisable/ Unexercisable	Exercisable/ Unexercisable
Lloyd T. Rochford	0	0	0/125,000	$0/$291,250
Stanley M. McCabe	0	0	0/125/000	$0/$291,250
William R. Broaddrick	0	0	0/250,000	$0/$582,500
Charles M. Crawford	0	0	0/50,000	$0/$116,500
Chris V. Kemendo, Jr.	0	0	0/50,000	$0/$116,500
Clayton E. Woodrum	0	0	0/50,000	$0/$61,500
Phillip W. Terry	0	0	0/250,000	$0/$582,500
Raymond H. Estep	0	0	0/100,000	$0/$233,000

The following table sets forth information concerning our executive stock option plan as of December 31, 2003.

	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 equity compensation plans (excluding securities in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	1,000,000	$3.76	-0-
Equity compensation plans not approved by security holders	--	--	--
Total	1,000,000	$3.76	1,000,000

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Item 11:

Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth, as March 10, 2004, 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 table also reflects what their ownership will be assuming completion of the sale of all shares in this offering (without taking into account the exercise of any warrants). 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	1,312,600 (1)	18.3%
Stanley M. McCabe	1,163,000 (2)	16.2%
William R. Broaddrick	54,500 (3)	*
Charles M. Crawford	10,000 (4)	*
Chris V. Kemendo, Jr.	10,100 (5)	*

Clayton E. Woodrum	--	*
All directors and executive officers as a group (6 persons)	2,550,200 (6)	35.6%

(1)

Includes 25,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.

(2)

Includes 25,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.

(3)

Includes 50,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.

(4)

Includes 10,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.

(5)

Includes 10,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.

(6)

Includes 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 7,163,097 shares of our common stock outstanding as of March 10, 2004,

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Item 12:

Certain Relationships and Related Transactions

The initial capital assets that were contributed to us were provided by Messrs. Rochford and McCabe. In contributing these assets to us in September 2000, no independent determination was made regarding the value of the oil and gas properties and related interests contributed in exchange for stock. In exchange for the initial 1,300,000 shares of common stock issued to each of Messrs. Rochford and McCabe, each contributed $33,695 in cash and a carried working interest obligation with future development costs estimated by an independent oil and gas engineer of approximately $134,000. Of the cash contributed, $61,174 was used to acquire our three initial leases. The estimated future development costs were accounted for as a receivable from Messrs. Rochford and McCabe. Total actual costs incurred by them in relation to the carried working in terest were $121,274. The difference of $12,726 was charged against additional paid in capital.

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, 2005. 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).

In 2001 and 2002 we acquired certain lease interests and had other business dealings with Petro Consultants, Inc. One of the principals of Petro Consultants, Inc., Mr. Robert J. Morley, was appointed our Vice President of Investor Relations in July 2002 and served as a member of the Board of Directors from February 2003, until his resignation of all positions as an officer and director in August 2003. Therefore, any transactions involving Petro Consultant between July 2002 and August 2003 could be deemed to have been entered into with an affiliate. Because we anticipated that we may continue to transact business with Petro Consultants, to avoid future issues that might arise due to such affiliation, Mr. Morley resigned his position as an officer and member of our board and forfeited all stock options (none of which had vested) whic h he had been granted by reason of his position as a board member.

Item 13:

Exhibits and Reports on Form 8-K

Reports on Form 8-K:

None

Exhibit Index:

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 December 31, 2003, among Arena Resources, Inc. and Bank of Oklahoma, N.A. (ii)

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

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 Form 10-KSB filed March 19, 2004.

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Item 14:

Principal Accountant Fees and Services

Hansen, Barnett & Maxwell served as our independent accountants for the years ended December 31, 2002 and 2003, and is expected to serve in that capacity for the current year. Principal accounting fees for professional services rendered for us by Hansen, Barnett & Maxwell for the years ended December 31, 2002 and 2003 are summarized as follows:

	2002(1)	**2003**(1)
Audit	$12,265	$ 29,617
Audit related	2,083	888
Tax	747	1,052
All other	-	-
Total	$ 15,095	$ 31,557

[1] The aggregate fees included in Audit are fees billed for the fiscal years for the audit of the Company s annual financial statements, review of the financial statements and statutory and regulatory filings or engagements. The aggregate fees included in each of the other categories are for fees billed in the fiscal years.

Audit Fees. Audit fees were for professional services rendered in connection with audits and quarterly reviews of financial statements of the Company and review of and preparation of consents for this registration statement for filing with the Securities and Exchange Commission.

Audit Related Fees. Audit related fees were for consultations regarding financial accounting and reporting standards primarily related to acquisitions of oil and gas properties.

Tax Fees. Tax fees related to services for tax compliance and consulting.

Audit Committee Pre-Approval Policies and Procedures. At its regularly scheduled and special meetings, the Audit Committee of the Board of Directors, which is comprised of independent directors knowledgeable of financial reporting, considers and pre-approves any audit and non-audit services to be performed by the Company s independent accountants. The Audit Committee has the authority to grant pre-approvals of non-audit services. That procedure was put into place promptly after July 30, 2002, the effective date of the Sarbanes-Oxley Act of 2002. At that time, the Audit Committee approved all non-audit services being performed at that time by the Company s independent accountants and adopted its pre-approval policies and procedures as set forth above. From the date of that meeting, there were no non-audit services performed by the Company s independent accountants that were not per-approved. Accordingly, the de minimus exception under Section 202 of the Sarbanes-Oxley Act of 2002 was applicable.

The Company s Audit Committee has considered whether the provision of the non-audit services provided by Hansen, Barnett & Maxwell is compatible with maintaining the accountant s independence.

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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: July 26, 2004

By:

/s/ Stanley McCabe

Mr. Stanley McCabe

Treasurer, Secretary

Date:

July 26, 2004

By:

/s/ William R. Broaddrick

Mr. William R. Broaddrick

Chief Financial Officer

Date:

July 26, 2004

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, President,

Chief Executive Officer

Date: July 26, 2004

By:

/s/ Stanley McCabe

Mr. Stanley McCabe

Treasurer, Secretary

Date:

July 26, 2004

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By:

/s/ Charles Crawford

Mr. Charles Crawford

Director

Date:

July 26, 2003

By:

/s/ Chris V. Kemendo, Jr.

Mr. Chris V. Kemendo, Jr.

Director

Date:

July 26, 2003

By:

/s/ Clayton E. Woodrum

Mr. Clayton E. Woodrum

Director

Date:

July 26, 2004

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ARENA RESOURCES, INC.

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2003 AND 2002

HANSEN, BARNETT & MAXWELL

A Professional Corporation

CERTIFIED PUBLIC ACCOUNTANTS

5 Triad Center, Suite 750

Salt Lake City, UT 84180-1128

Phone: (801) 532-2200

Fax: (801) 532-7944

www.hbmcpas.com

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Directors and the Stockholders

Arena Resources, Inc.

We have audited the accompanying balance sheets of Arena Resources, Inc. as of December 31, 2003 and 2002, and the related statements of operations, stockholders' equity, and cash flows for the years then ended. 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 auditing standards generally accepted in the United States of America. 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Arena Resources, Inc. as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

HANSEN, BARNETT & MAXWELL

Salt Lake City, Utah

January 20, 2004

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ARENA RESOURCES, INC.

BALANCE SHEETS

December 31,		**2003**		**2002**
ASSETS				
Current Assets				
Cash and cash equivalents	$	1,076,676	$	796,915
Account receivable		388,910		269,436
Short-term investments		25,234		-
Common stock subscription receivable		-		157,500
Prepaid expenses		28,935		1,128
Total Current Assets		1,519,755		1,224,979
Property and Equipment, using full cost accounting				
Oil and gas properties subject to amortization		8,463,400		4,884,804
Drilling advances		351,000		-
Support equipment		48,480		21,794
Office equipment		18,978		14,672
Total Property and Equipment		8,881,858		4,921,270
Less: Accumulated depreciation and amortization		(513,754)		(172,258)
Net Property and Equipment		8,368,104		4,749,012
Deferred Offering Costs		130,872		-
Long-Term Deposits		-		76,502
Total Assets	$	10,018,731	$	6,050,493
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities				
Accounts payable	$	229,522	$	173,174
Accrued liabilities		18,440		-
Put option		2,905		-
Accrued preferred dividends		-		114,685
Total Current Liabilities		250,867		287,859

Long-Term Liabilities				
Put option		-		50,604
Notes payable to officers		400,000		400,000
Asset retirement liability		607,200		-
Deferred income taxes		671,765		187,193
Total Long-Term Liabilities		1,678,965		637,797
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; 7,162,097 shares and 6,282,056 shares outstanding, respectively		7,162		6,282
Additional paid-in capital		6,994,925		5,287,189
Options and warrants outstanding		813,164		382,040
Retained earnings (deficit)		273,648		(550,674)
Total Stockholders' Equity		8,088,899		5,124,837
Total Liabilities and Stockholders' Equity	$	10,018,731	$	6,050,493

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

ARENA RESOURCES, INC.

STATEMENTS OF OPERATIONS

For the Years Ended December 31,	**2003**	**2002**

Oil and Gas Revenues	$ 3,665,477	$ 1,657,037
Costs and Operating Expenses		
Oil and gas production costs	1,149,136	594,863
Oil and gas production taxes	269,563	117,164
Depreciation and amortization	338,157	127,847
General and administrative expense	557,576	248,018
Total Costs and Operating Expenses	2,314,432	1,087,892
Other Income (Expense)		
Gain from change in fair value of put options	47,699	36,665
Accretion expense	(32,212)	-
Interest expense	(38,798)	(15,923)
Net Other Income (Expense)	(23,311)	20,742
Income Before Provision for Income Taxes and Cumulative Effect of Change in Accounting Principle	1,327,734	589,887
Provision for Deferred Income Taxes	(491,599)	(187,193)
Income Before Cumulative Effect of Change in Accounting Principle	836,135	402,694
Cumulative Effect of Change in Accounting Principle	(11,813)	-
Net Income	824,322	402,694
Preferred Stock Dividends	-	(798,018)
Income (Loss) Attributable to Common Shares	$ 824,322	$ (395,324)
Basic Income (Loss) Per Common Share		
Before cumulative effect of change in accounting principle	$ 0.12	$ (0.09)
Cumulative effect of change in accounting principle	-	-
Income (Loss) Attributable to Common Shares	$ 0.12	$ (0.09)
Diluted Income (Loss) Per Common Share		
Before cumulative effect of change in accounting principle	$ 0.12	$ (0.09)

Cumulative effect of change in accounting principle		-		-
Income (Loss) Attributable to Common Shares	$	0.12	$	(0.09)

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

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ARENA RESOURCES, INC.

STATEMENTS OF STOCKHOLDERS EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2002 AND 2003

	Preferred Stock		**Common Stock**		**Additional Paid-in Capital**	**Options and Warrants Outstanding**	**Receivable from Shareholders**	**Retained Earnings (Deficit)**
	Shares	**Amount**	**Shares**	**Amount**				
Balance, December 31, 2001	857,573	$ 1,274,021	3,604,500	$ 3,605	$ 817,811	$ 103,600.00	$ (5,733)	$ (155,350)
Issuance for cash	1,028,786	1,214,582	-	-	114,402	254,889	-	-
Issuance for cash to a related	-	-	70,000	70	88,130	-	-	-

party								
Issuance for property acquisitions	-	-	149,885	150	525,260	-	-	-
Preferred stock beneficial conversion dividends	-	114,402	-	-	-	-	-	(114,402)
Preferred stock cash dividends accrued	-	-	-	-	-	-	-	(274,589)
Preferred stock dividends paid with common stock	-	-	199,526	199	408,828	-	-	(409,027)
Conversion of preferred stock to common stock	(1,886,359)	(2,603,005)	1,886,359	1,886	2,601,119	-	-	-
Issuance upon exercise of warrants	-	-	74,786	75	215,565	(84,764)	-	-
Issuance for cash	-	-	286,000	286	493,535	108,315	-	-
Issuance for services	-	-	11,000	11	22,539	-	-	-
Collection of receivable from shareholder	-	-	-	-	-	-	5,733	-
Net Income	-	-	-	-	-	-	-	402,694
	-		6,282,056	6,282	5,287,189	382,040	-	(550,674)

Balance, December 31, 2002		-						
Issuance for cash	-	-	790,294	790	1,274,256	436,154	-	-
Issuance of warrants as commission for 2002 offering	-	-	-	-	(15,922)	15,922	-	-
Cancellation of shares for extension of lock up	-	-	(500)	-	-	-	-	-
Issuance for services	-	-	13,847	14	75,026	-	-	-
Warrant exercise	-	-	19,400	19	54,883	(20,952)	-	-
Issuance in property acquisitions	-	-	57,000	57	319,493	-	-	-
Net Income	-	-	-	-	-	-	-	824,322
Balance, December 31, 2003	-	$ -	7,162,097	$ 7,162	$ 6,994,925	$ 813,164	$ -	$ 273,648

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

ARENA RESOURCES, INC.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	**2003**	**2002**
Cash Flows From Operating Activities		
Net income	$ 824,322	$ 402,694
Adjustments to reconcile net income to net cash provided by operating activities:		
Shares issued for services	75,040	-
Depreciation and amortization	338,154	127,847
Services and use of office space contributed by officers	-	22,550
Interest capitalized on certificates of deposit	-	(1,502)
Gain from change in fair value of put option	(47,699)	(36,665)
Cumulative effect of change in accounting principle	11,813	-
Accretion of discounted liabilities	32,212	-
Changes in assets and liabilities:		
Accounts receivable	(119,474)	(258,730)
Prepaid expenses	(27,807)	(222)
Accounts payable and accrued liabilities	74,790	127,583
Deferred income taxes	491,599	187,193
Net Cash Provided by Operating Activities	1,652,950	570,748
Cash Flows from Investing Activities		
Purchase of oil and gas properties	(3,050,558)	(2,603,279)
Purchase of support and office equipment	(30,992)	(29,388)
Increase in long-term deposits	-	(25,000)
Maturity of long-term deposits	51,268	-
Net Cash Used in Investing Activities	(3,030,282)	(2,657,667)
Cash Flows From Financing Activities		

Proceeds from issuance of common stock and warrants, net of offering costs	1,580,328	532,836
Proceeds from issuance of preferred stock, net of offering costs	-	1,589,606
Proceeds from warrant exercise	33,950	130,876
Collection of common stock subscription receivable	157,500	-
Proceeds from issuance of note payable	-	400,000
Payment on note payable	-	(18,000)
Payment of dividends to preferred stockholders	(114,685)	(196,048)
Net Cash Provided by Financing Activities	1,657,093	2,439,270
Net Increase in Cash and Cash Equivalents	279,761	352,351
Cash and Cash Equivalents, Beginning of Year	796,915	444,564
Cash and Cash Equivalents, End of Year	$ 1,076,676	$ 796,915

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