ARENA RESOURCES INC
Form 424B1
August 10, 2004
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Filed Pursuant to Rule 424(b)(1)

Registration No. 333-113712

PROSPECTUS

1,450,000 Units

Each Unit Consisting of One Share of Common Stock

and

One Warrant to Acquire One Share of Common Stock

Our common stock is traded on the American Stock Exchange under the symbol ARD . The offering price of the units was determined largely by reference to our common stock whose closing price was $6.10 per share on August 9, 2004. The units offered hereby have been approved for trading on the American Stock Exchange under the symbol ARD.u . The common stock and warrants will initially trade as a unit, until separated, at which time the common stock and warrants will trade separately on the American Stock Exchange. Currently, no public market exists for the units or separately for the warrants.

Investing in our securities involves risks that are described in the Risk Factors section beginning on page 13 of this prospectus.

	Per Unit	Total
Public offering price	$ 6.10	$ 8,845,000
Underwriting discount	$ 0.49	$ 707,600
Proceeds to us, before expenses	$ 5.61	$ 8,137,400

The unit offering price consists of $6.00 per share of common stock and $0.10 per warrant. The underwriters may also purchase up to an additional 217,500 units from us, less the underwriting discount, within 60 days from the date of this prospectus to cover over-allotments.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the units to purchasers on or about August 13, 2004.

Neidiger, Tucker, Bruner, Inc. **Lane Capital Markets**

vFinance Investments, Inc.

The date of this prospectus is August 10, 2004

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ARENA RESOURCES, INC.

Property Locations

Arena Resources, Inc. is engaged in oil and natural gas acquisition, exploration, development and production, with activities currently in Oklahoma, Texas, New Mexico and Kansas.

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

You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where the offer or sale is not permitted.

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PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including Risk Factors and our financial statements and the notes to those financial statements included elsewhere in this prospectus. Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their over-allotment option. If the underwriters exercise their option, net proceeds therefrom will be utilized for the acquisition of additional properties. The reserve information contained in this prospectus is as of December 31, 2003, unless otherwise indicated. The operating information and other data contained in this prospectus are as of March 31, 2004, unless otherwise indicated. We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms included in this prospectus.

About Our Company

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. We believe we can minimize near term risk by delaying exploration or development activities on certain property interests we own (which would otherwise require us to finance such activities from outside sources) until we have a base of producing properties that will provide sufficient cash from operations to undertake further exploration or development activities.

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 increased our proved reserves to approximately 7.6 million Boe (barrels of oil equivalent), through the acquisition of interests in 10 producing 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 $7.28 million on acquisitions and capital projects during 2002 and 2003.

On May 7, 2004, we completed the acquisition of an 82.2% working interest in a lease in Lea County, New Mexico (the East Hobbs Unit), with a net revenue interest of approximately 67.6%, and proved reserves of approximately 3.0 million Boe. With this acquisition, we estimate our total proved reserves to be approximately 10.6 million Boe. The acquisition cost of the East Hobbs Unit was approximately $10 million.

Including the operations from the East Hobbs Unit, 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 23% of our proved reserves are classified as proved developed producing, or PDP. Approximately 1% of our proved reserves are classified as proved developed non-producing, or PDNP, and approximately 76% are classified as proved undeveloped, or PUD.

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The following table summarizes our total net proved reserves and pre-tax PV10 value by state, as of December 31, 2003. Additionally, the table summarizes the total net proved reserves and pre-tax PV10 value of the East Hobbs Unit, as of March 1, 2004.

	Proved Reserves			
State	Oil (Bbls)	Natural Gas (Mcf)	Total (Boe)(1)	Pre-Tax PV10 Value
Oklahoma	3,465,351	658,484	3,575,089	$ 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 December 31, 2003	7,050,167	3,408,754	7,618,283	$ 66,584,956
East Hobbs Unit (New Mexico)	2,730,837	1,637,640	3,003,777	$ 38,702,806

(1) Boe is barrels of oil equivalent , with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Business Strategy

Our goal is to increase stockholder value by investing in oil and gas properties with attractive rates of return on capital employed. We plan to achieve this goal through the near- and intermediate-term strategy of acquiring properties with proved reserves that provide immediate cash flow with opportunities for further development. Once we have acquired a more substantial base of assets, our long-term plan is to increase our development activities. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing Profitable Acquisitions. We have pursued and intend to continue to pursue acquisitions of proved properties that we believe to have development potential, while immediately providing a source of cash flow. We target low-risk properties with the opportunity for further development, including drilling offset wells, waterfloods and multiple pay zones. We believe the key to successfully undertaking such a program is conducting substantial due diligence prior to purchasing a property. To allow us to do this, we utilize both an experienced team of in-house management, as well as independent engineers who can identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. Our due diligence process results in our rejection of a significant number of properties that fail to suit our business model.

From August 2000 through May 2004, we acquired leases on 11 producing properties at an aggregate cost of approximately $18.8 million, representing approximately 10.6 million Boe of proved reserves (at an average cost of $1.77 per Boe).

Developing Existing Properties. We believe that there will be significant value created by conducting additional drilling activities on identified undeveloped opportunities on our current properties, and on properties we hope to acquire in the future. We own interests in a total of 14,273 gross (10,541 net) developed acres and operate essentially 100% of the net pre-tax PV10 value of our proved reserves. In addition, as of May 7, 2004, we owned interests in approximately 2,615 gross (2,106 net) undeveloped acres that contain many development opportunities. We currently estimate that an additional $6 million to $8 million in acquisitions will put us in a position where the cash flow from our properties will be sufficient to fund our development activities; however, these estimates are subject to numerous factors beyond our control, including the prices at which we may be able to acquire properties that fit our business plan.

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

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allocation and the decision-making processes related to our production, development and exploration activities. For the year ended December 31, 2003, our lease operating expense (which includes only oil and gas production costs) per Boe averaged $8.92 and general and administrative costs averaged $4.33 per Boe produced. For the three months ended March 31, 2004, our lease operating expense per Boe produced averaged $8.54 and general and administrative costs averaged $4.82 per Boe produced.

Recent and Proposed Activities

During the year ended December 31, 2003, we invested $2.62 million in new lease acquisitions, and $351,000 in drilling advances. As of May 7, 2004, we acquired the East Hobbs Unit in Lea County, New Mexico, for approximately $10 million. With this most recent acquisition, we are closer to having a base of producing properties that we believe sufficient to fund the development phase of our business plan. However, we anticipate seeking one or two more acquisitions in 2004, prior to commencing a more aggressive development program. We discuss our recent and proposed activities below under Business and Properties.

Risk Factors

An investment in our securities involves certain risks that should be carefully considered by prospective investors. See Risk Factors.

Corporate Information

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.

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The Offering

Securities Offered	1,450,000 units, with each unit consisting of one share of our common stock priced at $6.00 and one warrant to purchase one share of our common stock priced at $0.10, for an aggregate offering price of $6.10 per unit.
Warrant attributes	Each warrant is exercisable to purchase one share of our common stock at an exercise price of $7.32 (120% of the public offering price of the unit) during the four years ending August 9, 2008, subject to redemption rights.
Common stock to be outstanding after the offering	8,642,097 shares (prior to exercise of warrants to acquire 1,450,000 shares).
Use of proceeds	We plan to use the net proceeds to repay a portion of bank financing incurred in connection with the acquisition of the East Hobbs Unit, and to acquire additional oil and gas prospects.
Risk factors	Please read Risk Factors for a discussion of factors you should consider carefully before deciding to invest in shares of our common stock.
American Stock Exchange symbol stock	ARD .
American Stock Exchange symbol units	ARD.u
American Stock Exchange symbol warrants	ARD.ws

Our common stock is currently traded on the American Stock Exchange. Following the conclusion of this offering until the units are divided into their separate components of one share of common stock and one warrant, the units will trade on the American Stock Exchange (at the same time, but separately from, the currently issued shares of our common stock already trading on the American Stock Exchange). In an effort to avoid potential disruption in the market, each unit will be divided into its separate component of one share of common stock and one warrant upon the earlier of one year from the date of this prospectus, or upon thirty (30) days prior written notice from us. However, we will not allow separation of the units until the earlier to occur of 60 days immediately following this offering or the exercise by the underwriters of the entire over-allotment option. Following the separation of the units, the shares of common stock will trade on the American Stock Exchange (and will be indistinguishable from our common stock currently trading on such exchange), and the warrants will trade separately from the common stock on such exchange. The units will cease to exist at that time.

The number of shares outstanding after the offering excludes shares reserved for issuance under outstanding options and warrants. As of March 31, 2004, we had granted options to directors and employees to purchase 1,000,000 shares of common stock at an average price of $3.76 per share, of which options to acquire 190,000 shares are currently exercisable. In addition, at March 31, 2004, there were outstanding warrants to purchase 1,430,723 shares of our common stock at an average price of $4.47 per share, all of which are currently exercisable. See Capitalization.

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Summary Historical Financial Information

The summary historical financial information set forth below should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and with our financial statements and the notes to those financial statements included elsewhere in this prospectus. The income statement information for the year ended December 31, 2001, and the balance sheet information as of December 31, 2001 and March 31, 2003, were derived from our financial statements that are not included herein.

	Year Ended December 31,			For the Three Months Ended March 31,	
	2001	2002	2003	2003	2004
Income Statement Information:					
Revenues and other income					
Oil and gas revenues	$ 311,733	$ 1,657,037	$ 3,665,477	$ 807,021	$ 1,200,400
Gain from change in fair value of put options		36,665	47,699	4,775	
Total revenues and other income	311,733	1,693,702	3,713,176	811,796	1,200,400
Costs and expenses					
Lease operating	106,927	594,863	1,149,136	242,071	316,290
Production taxes	14,797	117,164	269,563	53,950	78,707
Depreciation, depletion and amortization	44,148	151,197	360,282	59,747	111,120
General and administrative expense	127,696	248,018	557,576	143,631	178,202
Interest expense		15,923	38,798	9,863	9,113
Accretion expense			32,212	4,782	12,295
Total costs and expenses	293,568	1,127,165	2,407,567	514,044	705,727
Income before taxes	18,165	566,537	1,305,609	297,752	494,673
Provision for deferred income taxes		(179,488)	(484,298)	(111,433)	(185,032)
Cumulative effect of change in accounting principles			(11,813)	(11,813)	
Net income	18,165	387,049	809,498	174,506	309,641
Preferred stock dividends	(63,092)	(798,018)			
Income (loss) attributable to common shares	$ (44,927)	$ (410,969)	$ 809,498	$ 174,506	$ 309,641
Operating Data:					
Net production:					
Oil (Bbl)	12,895	58,717	117,646	23,590	33,783
Natural gas (Mcf)	4,776	46,819	67,329	10,912	19,323
Total (Boe)	13,691	66,520	128,868	25,408	37,003
Average sales price:					
Oil (Bbl)	$ 23.45	$ 26.09	$ 29.06	$ 32.18	$ 33.24
Natural gas (Mcf)	1.95	2.67	3.67	4.40	4.00
Total (per Boe)	22.77	24.91	28.44	31.76	32.44
Other Financial Information:					

Net cash provided by operating activities	$ 84,023	$ 570,748	$ 1,652,950	$ 278,265	$ 568,710
Capital expenditures	1,584,645	3,268,373	4,015,313	153,715	314,066
EBITDA(1)	62,313	696,992	1,689,202	367,369	627,201

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	As of December 31,			As of March 31, 2004	
	2001	2002	2003	Actual	Pro Forma[2]
Balance Sheet Information:					
Total assets	$ 2,137,689	$ 6,027,143	$ 9,973,256	$ 10,491,792	$ 20,662,315
Long-term liabilities		630,092	1,663,959	1,861,287	9,902,174
Stockholders equity	2,037,954	5,109,192	8,058,430	8,389,821	8,389,821

(1) We define EBITDA as earnings before interest, taxes, depreciation, depletion and amortization. We further include in our calculation of EBITDA the effects of any cumulative change in accounting principle, accretion expense and the gain (loss) from changes in the fair value of certain outstanding put options. EBITDA is not a measure of performance calculated in accordance with generally accepted accounting principles in the United States, or GAAP. Although not prescribed under GAAP, we believe the presentation of EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. EBITDA, as we calculate it, is likely not comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use.

The following table presents a reconciliation of our net income to EBITDA:

	Year Ended December 31,			For the Three Months Ended March 31,	
	2001	2002	2003	2003	2004
Net income	$ 18,165	$ 387,049	$ 809,498	$ 174,506	$ 309,641
Cumulative effect of change in accounting principle			11,813	11,813	
Deferred income taxes		179,488	484,298	111,433	185,032
Interest expense		15,923	38,798	9,863	9,113
Accretion expense			32,212	4,782	12,295
Gain from change in fair value of put options		(36,665)	(47,699)	(4,775)	
Depreciation, depletion and amortization	44,148	151,197	360,282	59,747	111,120
EBITDA	$ 62,313	$ 696,992	$ 1,689,202	$ 367,369	$ 627,201

(2) On May 7, 2004 we acquired the East Hobbs Unit for approximately $10,000,000. Our unaudited pro forma balance sheet included with our financial statements herein (at page F-2) reflects the impact of this acquisition as if it had occurred as of March 31, 2004. The summary pro forma balance sheet information as of March 31, 2004 reflects only the effect of the acquisition and the related financing and does not include any of the potential effects from this offering.

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Summary Historical Reserve and Operating Data

The following table presents summary information regarding our estimated net proved oil and natural gas reserves as of December 31, 2001, 2002 and 2003 and, with respect to the East Hobbs Unit, as of March 1, 2004. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read Business and Properties Summary of Oil and Natural Gas Properties and Projects.

	As of December 31,		
	2001	2002	2003
Reserve Data:			
Total estimated net proved reserves:			
Oil (Bbls)	494,823	4,113,936	7,050,167
Natural gas (Mcf)	2,960,373	3,187,757	3,408,754
Total (Boe)	988,219	4,645,230	7,618,283
Estimated net proved developed reserves:			
Oil (Bbls)	142,371	750,464	1,580,521
Natural gas (Mcf)	1,038,564	1,106,639	1,612,738
Total (Boe)	315,465	943,904	1,849,311
Estimated future net revenues before income taxes	$ 11,071,319	$ 74,076,974	$ 140,259,671
Present value of estimated future net revenues before income taxes (1)(2)	$ 7,373,058	$ 44,578,108	$ 66,584,952
Standardized measure of discounted future net cash flows (3)	$ 5,203,372	$ 27,997,824	$ 45,006,097

(1) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

(2) The December 31, 2001 amount was calculated using a period end average realized oil price of $19.25 per barrel and a period end average realized natural gas price of $2.52 per Mcf; the December 31, 2002 amount was calculated using a period end average realized oil price of $24.00 per barrel and a period end average realized natural gas price of $3.00 per Mcf; the December 31, 2003 amount was calculated using a period end average realized oil price of $29.25 per barrel and a period end average realized natural gas price of $3.46 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income tax discounted at 10%.

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	As of March 1, 2004
East Hobbs Unit Reserve Data:	
Total estimated net proved reserves:	
Oil (Bbls)	2,730,837
Natural gas (Mcf)	1,637,640
Total (Boe)	3,003,777
Estimated net proved developed reserves:	
Oil (Bbls)	509,486
Natural gas (Mcf)	447,839
Total (Boe)	584,126
Estimated future net revenues before income taxes	$ 76,110,344
Present value of estimated future net revenues before income taxes(1)(2)	$ 38,702,806
Standardized measure of discounted future net cash flows(3)	$ 25,543,852

(1) The present value of estimated future net revenues attributable to the East Hobbs reserves were prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

(2) The March 1, 2004 amount was calculated using an oil price of $35.00 per barrel and a natural gas price of $4.73 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income tax discounted at 10%.

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The following table presents summary information regarding our historical operating data for the years ended December 31, 2001, 2002 and 2003 and as of March 31, 2003 and 2004 (which are derived from our financial statements):

	Year Ended December 31,			Three Months Ended March 31,	
	2001	2002	2003	2003	2004
Operating Data:					
Net production:					
Oil (Bbls)	12,895	58,717	117,646	23,590	33,783
Natural gas (Mcf)	4,776	46,819	67,329	10,912	19,323
Total (Boe)	13,691	66,520	128,868	25,408	37,003
Net sales:					
Oil	$ 302,424	$ 1,532,045	$ 3,418,480	$ 759,038	$ 1,123,034
Natural gas	9,309	124,992	246,997	47,983	77,366
Total	$ 311,733	$ 1,657,037	$ 3,665,477	$ 807,021	$ 1,200,400
Average sales price:					
Oil (per Bbl)	$ 23.45	$ 26.09	$ 29.06	$ 32.18	$ 33.24
Natural gas (per Mcf)	1.95	2.67	3.67	4.40	4.00
Total (per Boe)	22.77	24.91	28.44	31.76	32.44
Average (per Boe):					
Lease operating expenses	$ 7.81	$ 8.94	$ 8.92	$ 9.53	$ 8.54
Production taxes	1.08	1.76	2.09	2.12	2.13
Depreciation, depletion and amortization expense	3.22	2.27	2.79	2.35	3.00
General and administrative expenses	9.33	3.73	4.33	5.65	4.82
Net income (loss) after preferred stock dividends	(3.28)	(6.17)	6.28	6.87	8.36

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RISK FACTORS

You should carefully consider each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading prices of the securities could decline and you may lose all or part of your investment.

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

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

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

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

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

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

Because a substantial percentage of our proven properties are proved undeveloped (approximately 76%), or proved developed non-producing (approximately 1%), we will require significant additional capital to develop such properties before they may become productive. Further, because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be developed to the extent that they result in positive cash flow. Even if we are successful in our development efforts, it could take several years for a significant portion of our undeveloped properties to be converted to positive cash flow.

While our current business plan is to fund the development costs with cash flow from our other producing properties, if such cash flow is not sufficient we may be forced to seek alternative sources for cash, through the issuance of additional equity or debt securities, increased borrowings or other means. See, Business and Properties Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves.

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

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

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

If we are not successful in acquiring additional producing properties, rather than utilizing cash flow from existing production to finance future development, we may be forced to delay production, or incur debt or sell additional equity as sources of financing our development program.

Our current business strategy is to continue our program of acquiring properties that satisfy our business model, until we have a base of producing properties from which we can utilize cash flow from production to further finance additional development of those properties. We anticipate using approximately $6 million of the proceeds of this offering for such acquisition purposes. If, after utilizing the proceeds of this offering to conclude our acquisition program, our cash flow from production is not sufficient to develop our properties to their complete potential, we will be required to delay or curtail anticipated development activities, or alter or increase our capitalization substantially through the issuance of debt or other equity securities, the sale of production payments, increase borrowings or other means. Each of these alternatives involves more risk to investors (and enhances the possibility that the trading price of our stock and the units would be negatively impacted by reason of a balance sheet reflecting a less favorable capital structure or dilution of existing shareholders) than if we are able to fund development activities from existing cash flow.

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

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

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;

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- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

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

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

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

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

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. Please read Business and Properties Summary of Oil and Natural Gas Properties and Projects for information about our oil and natural gas reserves.

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

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

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on

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prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If future values decline or costs increase it could negatively impact our ability to finance operations, and individual properties could cease being commercially viable, affecting our decision to continue operations on producing properties or to attempt to develop properties. All of these factors would have a negative impact on earnings and net income, and most likely the trading price of our securities. These factors could also result in the acceleration of debt repayment and a reduction in our borrowing base under our credit facilities.

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

We describe some of our current prospects and our future plans to explore those prospects in this prospectus. A prospect is a property on which we have identified what we believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. This risk may be enhanced in our situation, due to the fact that a significant percentage (76%) of our proved reserves are currently proved undeveloped reserves. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

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

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

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

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

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

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

- discharge permits for drilling operations;

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

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

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

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

The recent increase in debt associated with property acquisitions could reduce our financial flexibility.

As of December 31, 2003, we had a $20 million credit facility in place with a current borrowing base of $4 million. On April 14, 2004, we established a new $15 million credit facility with an $8.5 million initial borrowing base. Also on April 14, 2004, we entered into to a bridge financing arrangement for $2 million from the same lender. On May 7, 2004, we drew approximately $8 million under the revolving credit facility and borrowed the entire $2 million under the bridge financing arrangement to fund the acquisition of the East Hobbs Unit.

While we intend to repay approximately $2 million of this borrowing with a portion of the proceeds of this offering, this increase in the level of our indebtedness could affect our operations in several ways, including the following:

a significant portion of our cash flow could be used to service the indebtedness,

a high level of debt increases our vulnerability to general adverse economic and industry conditions,

the covenants contained in our credit facility limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments,

a high level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

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

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

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

The loss of senior management could adversely affect us.

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

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

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations. As the price of oil and natural gas increases, the demand for production equipment and personnel will likely also increase, potentially resulting, at least in the near-term, in shortages of equipment and personnel. In addition, larger producers may be more likely to secure access to such equipment by virtue of offering drilling companies more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, not only would this potentially delay our ability to convert our reserves into cash flow, but could also significantly increase the cost of producing those reserves, thereby negatively impacting anticipated net income.

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

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

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

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

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

Risks Relating to the Offering and Our Common Stock and Warrants

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

Prior to this offering (partly because approximately 34% of our stock has been held by our Chairman and our President and, therefore, is restricted stock see, Stock Ownership of Certain Beneficial Owners and Management), our common stock has had a relatively low public float . In addition, there has been no public market for our warrants. The public offering price of our units under this offering may not be indicative of the market price of our common stock either before or after this offering, or of the market price of the units after this offering. In addition, our stock price may be volatile.

Additionally, approximately 2,049,000 shares of our common stock are restricted shares under Rule 144, but could be currently sold with little difficulty under the provisions of Rule 144(k). We also estimate that approximately 1,840,000 additional shares of common stock that are currently restricted , will soon be capable of being resold under Rule 144. See Shares Eligible for Future Sale.

Finally, as of the date of this prospectus there are warrants outstanding to purchase 1,405,723 shares of common stock, as well as options to purchase 1,000,000 shares of common stock (vesting at 20% per year over the next four years).

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

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The determination of the public offering price of the units and the stock and warrants comprising the units was determined by negotiation, and may not reflect the actual trading price of the units, the stock or warrants on any market that may develop.

The public offering price of the stock and warrants comprising our units was determined by negotiations between the representatives of the underwriters and us, based on numerous factors, including the trading price of our common stock, which we discuss in the Underwriting section of this prospectus. This price may not be indicative of the market price for our common stock either before or after this offering. The market price of our common stock and the units could be subject to significant fluctuations after this offering, and may decline below the public offering price. In addition, at the time the units are split into their separate components of common stock and warrants, the market price of each of these separate components may be less than the market price at which the units were trading prior to separation. You may not be able to resell your units at or above the offering price. The following factors could affect our unit price:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of research reports by analysts;
- speculation in the press or investment community;
- sales of significant shares of our common stock by stockholders who are not subject to lock-up agreements;
- actions by institutional investors;
- general market conditions, including fluctuations in commodity prices and;
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock and the units.

Purchasers of our securities in prior unregistered offerings could be entitled to rescission rights.

Subsequent to our initial public offering completed in March 2001, we have issued our common stock and warrants in several private transactions as a source of raising capital to fund our acquisitions and operations. It is possible, by reason of certain procedural or similar failures (i.e., the failure to file certain notices in connection with the sales) that a technical violation of some securities laws may have occurred at the time. If a holder of our securities was successful in claiming that the securities were issued to such holder without a valid exemption from registration, we believe that the remedy to such holder would be a rescission of the sale, pursuant to which the holder could be entitled to recover the amount paid for the security, plus interest (usually at a statutory rate prescribed by state law).

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

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

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control, which may include statements about our:

- business strategy;
- reserves;
- financial strategy;
- production;
- uncertainty regarding our future operating results;
- plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All statements, other than statements of historical fact included in this prospectus, 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 prospectus, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. All forward-looking statements speak only as of the date of this prospectus. 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 prospectus 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 prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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USE OF PROCEEDS

We estimate that the Company will receive net proceeds of approximately $7,430,895 million from the sale of the 1,450,000 units in this offering based upon an assumed offering price of $6.10 per unit, after deducting underwriting discounts and commissions and estimated offering expenses. We intend to use these proceeds to repay approximately $2 million of the debt incurred in connection with our recent acquisition of the East Hobbs Unit, and utilize the balance to fund the acquisition of additional properties. We anticipate that the portion of the proceeds allocated for acquisitions will be utilized during the next twelve months. At this time, we have under consideration several potential prospects, but we have no firm commitments for the acquisition of any specific properties.

It is our current intention to continue to focus our acquisition strategy on properties in our present areas of operation Oklahoma, Texas, New Mexico and Kansas. Our business strategy is to expand our base of proven properties until such time as we believe the existing production from such properties will be sufficient to fund further development. We cannot specifically predict when we will have achieved this critical mass (i.e., the time when our base of producing properties will generate sufficient cash flow to finance our further development activities), because of several factors, including: the fluctuation in oil and gas prices; the inability to exactly predict the acquisition prices of properties that we may find suitable to include in our portfolio; and, the inability to accurately forecast production characteristics of our existing properties as well as those that we may acquire in the future. However, we currently estimate that if we are able to find additional properties with anticipated production characteristics generally similar to those we currently own, we will achieve this critical mass with acquisitions of additional properties valued at approximately $6 million to $8 million.

Because of the inherent uncertainties associated with an acquisition program such as ours, it is possible that we may later determine that a portion of the proceeds of this offering would be better utilized to commence exploitation and development opportunities on properties we already own. Factors such as a significant increase in oil and natural gas prices (which could have the effect of driving the cost of new acquisitions above what we are willing to pay) could also lead to our determination that it is more economically feasible to begin a more aggressive drilling and exploration program sooner than we currently anticipate.

If the underwriters over-allotment option is exercised in full, we estimate that our net proceeds will be up to an additional $1,182,134. These additional net proceeds will also be allocated to fund acquisition costs for additional properties. We believe that with our current cash flow from existing properties and our bank facility, we will have sufficient working capital to carry on our intended operations.

DIVIDEND POLICY

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.

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CAPITALIZATION

The following table sets forth, as of March 31, 2004, the actual capitalization of Arena Resources, Inc., the pro forma capitalization to present the estimated effects of the financing transactions associated with the acquisition of the East Hobbs Unit on the financial position of the Company as if they had occurred on March 31, 2004 (see also our financial statements included herein beginning at page F-1), and the capitalization, on an as adjusted basis to reflect our receipt of the estimated net proceeds from the sale of units at an assumed offering price of $6.10, after deducting underwriting discounts and other estimated offering expenses. You should read this table in conjunction with our financial statements and the notes to those financial statements included elsewhere in this prospectus.

	March 31, 2004		
	Actual	Pro Forma	As Adjusted
Cash and cash equivalents	$ 1,238,282	$ 1,238,282	$ 6,914,982
Short-term debt	$	$ 2,000,000	$
Long-term debt	400,000	8,408,440	8,408,440
Total debt	400,000	10,408,440	8,408,440
Stockholders equity			
Common Stock: $0.001 par value, 100,000,000 shares authorized, 7,167,097 shares issued and outstanding (actual and pro forma); 8,617,097 shares issued and outstanding (as adjusted)[(1)]	7,167	7,167	8,617
Preferred Stock: $0.001 par value, 100,000,000 shares authorized, no shares issued or outstanding (actual and pro forma); no shares issued and outstanding (as adjusted)			
Additional paid-in capital	7,019,494	7,019,494	12,763,543
Options and warrants outstanding	810,340	810,340	2,495,881
Retained Earnings	552,820	552,820	552,820
Total stockholders equity	8,389,821	8,389,821	15,820,861
Total capitalization	$ 8,789,821	$ 18,798,261	$ 24,229,301

(1) The foregoing does not give effect to 2,430,723 shares of common stock issuable upon the exercise of outstanding options and warrants as of March 31, 2004, 1,450,000 shares of common stock issuable upon exercise of the warrants which are part of the units being offered hereby, 217,500 shares of common stock and 217,500 warrants issuable upon exercise of the underwriters over-allotment option for units, or 25,000 shares which have been issued pursuant to the exercise of warrants subsequent to March 31, 2004.

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PRICE RANGE OF 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 and one-half 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	$ 7.08	$ 5.85
2nd Quarter 2004	$ 9.65	$ 6.98
3rd Quarter 2004 (through August 9)	$ 7.46	$ 6.08

On August 9, 2004 the closing price of our common stock on the American Stock Exchange was $6.10

The units have been approved for listing, subject to issuance, under the symbol ARD.u . The units will be traded on the American Stock Exchange in that form until the earlier of one year from the date of this prospectus, or upon thirty days prior written notice from us. However, we will not allow separation of the units until the earlier to occur of 60 days immediately following this offering or the exercise by the underwriters of the entire over-allotment option. Our common stock is currently traded on the American Stock Exchange. We believe that if the units were capable of being separated immediately following the closing of this offering, it could have an artificial impact on the trading price of our currently outstanding shares of common stock. By not allowing the units to be immediately split, we hope to avoid any such potential market impact.

When each unit is separated into its components, we will issue (by book entry transfer for those units held in street name) to each unit holder of record, one share of common stock and one warrant to purchase one share of common stock. At that time each share of common stock and each warrant will be freely and separately tradeable on the American Stock Exchange under the symbols ARD and ARD.ws , respectively. The units will cease to exist at that time.

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SELECTED HISTORICAL FINANCIAL INFORMATION

The selected historical financial information set forth below should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and with our financial statements and the notes to those financial statements included elsewhere in this prospectus. The income statement information and cash flow statement information for the year ended December 31, 2001 was derived from our financial statements, that are not included herein.

	Year Ended December 31,			For the Three Months Ended March 31,	
	2001	2002	2003	2003	2004
	(dollars in thousands except per share data)				
Income Statement Information:					
Revenues and other income:					
Oil and gas revenues	$ 312	$ 1,657	$ 3,665	$ 807	$ 1,200
Gain from change in fair value of put options		37	48	5	
Total revenues	312	1,694	3,713	812	1,200
Costs and expenses:					
Lease operating	107	595	1,149	242	316
Production taxes	15	117	270	54	79
Depreciation, depletion and amortization	44	152	360	60	111
General and administrative expense	128	248	558	144	178
Interest expense		16	39	10	9
Accretion expense			32	5	12
Total costs and expenses	294	1,128	2,408	514	705
Income before income taxes	18	566	1,305	298	495
Provision for income taxes:					
Current					
Deferred		(179)	(484)	(111)	(185)
Total provision for income taxes		(179)	(484)	(111)	(185)
Income before cumulative effect of change in accounting principle	18	387	821	187	310
Cumulative effect of change in accounting principle			(12)	(12)	
Preferred stock dividends	(63)	(798)			
Net income (loss) attributable to common shares	$ (45)	$ (411)	$ 809	$ 175	$ 310
Basic Income (Loss) Per Common Share					
Before cumulative effect of change in accounting principle	$ (0.01)	$ (0.09)	$ 0.12	$ 0.03	$ 0.04
Cumulative effect of change in accounting principle					
Net Income (Loss) Attributable to Common Shares	$ (0.01)	$ (0.09)	$ 0.12	$ 0.03	$ 0.04
Diluted Income (Loss) Per Common Share					
Before cumulative effect of change in accounting principle	$ (0.01)	$ (0.09)	$ 0.11	$ 0.03	$ 0.04

Cumulative effect of change in accounting principle					
Net Income (Loss) Attributable to Common Shares	$ (0.01)	$ (0.09)	$ 0.11	$ 0.03	$ 0.04

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	As of December 31,		As of March 31, 2004	
	2002	2003	Actual	Pro Forma[1]
	(dollars in thousands)			
Balance Sheet Information:				
Total assets	$ 6,027	$ 9,973	$ 10,492	$ 20,662
Long-term liabilities	631	1,663	1,861	9,902
Stockholders equity	5,109	8,058	8,390	8,390

(1) On May 7, 2004 we acquired the East Hobbs Unit for approximately $10,000,000. Our unaudited pro forma balance sheet included with our financial statements herein (at page F-2) reflects the impact of this acquisition as if it had occurred as of March 31, 2004. The summary pro forma balance sheet information as of March 31, 2004 reflects only the effect of the acquisition and the related financing and does not include any of the potential effects from this offering.

	Year Ended December 31,			For the Three Months Ended March 31,	
	2001	2002	2003	2003	2004
	(dollars in thousands)				
Cash Flow Statement Information:					
Net cash provided by operating activities	$ 84	$ 571	$ 1,653	$ 278	$ 569
Net cash used in investment activities	(1,072)	(2,658)	(3,030)	(154)	(314)
Net cash provided by (used in) financing activities	1,414	2,439	1,657	295	(93)

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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 selected historical financial data and our accompanying financial statements and the notes to those financial statements included elsewhere in this prospectus. 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 prospectus, particularly in Risk Factors.

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 upside potential through further development.

We have increased our proved reserves to approximately 10.6 Boe since our inception in August 2000, with the recent $10 million investment in the East Hobbs Unit, and by investing approximately $4 million in acquisitions in 2003, following total capital expenditures of approximately $3.2 million in 2002 and approximately $1.6 million in 2001.

Our capital budget for the remainder of 2004 is approximately $6 million. This budget will be funded from a portion of the net proceeds from the sale of units in this offering, 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 for the acquisition of additional reserves in 2004. With our recent acquisition of the East Hobbs Unit, we are nearer to fulfilling our business plan of acquiring a sufficient base of producing properties to enable us to begin development activities funded from the cash flow from production. We believe the acquisition of additional properties utilizing our proposed capital budget for the remainder of this year will enable us to achieve our critical mass of producing properties. However, this is an estimate only, and could change depending on a variety of factors, including fluctuating oil and gas prices, increasing prices of acquisition targets, and the particular mix of reserves on properties that we may acquire. Therefore, 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 this offering was not successful and we are unable to obtain alternate sources of financing for such acquisition activities. 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 less than the development activities that we anticipate conducting assuming this offering (and the completion of our 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 (i.e., where unrelated third parties serve as the operators) 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 offer an attractive mix of producing properties and development potential. 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

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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 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. See Risk Factors for a more detailed discussion of these risks.

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 cause 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,			For the Three Months Ended March 31,	
	2001	**2002**	**2003**	**2003**	**2004**
Net production:					
Oil (Bbls)	12,895	58,717	117,646	23,590	33,783
Natural gas (Mcf)	4,776	46,819	67,329	10,912	19,323
Net sales:					
Oil	$ 302,424	$ 1,532,045	$ 3,418,480	$ 759,038	$ 1,123,034
Natural gas	9,309	124,992	246,997	47,983	77,366
Average sales price:					
Oil (per Bbl)	$ 23.45	$ 26.09	$ 29.06	$ 32.18	$ 33.24
Natural gas (per Mcf)	1.95	2.67	3.67	4.40	4.00
Production costs and expenses:					
Lease operating expenses	$ 106,927	$ 594,863	$ 1,149,136	$ 242,071	$ 316,290
Production taxes	14,797	117,164	269,563	53,950	78,707
Depreciation, depletion and amortization expense	44,148	151,197	360,282	59,747	111,120
General and administrative expenses	127,696	248,018	557,576	143,631	178,202

For the Three Months Ended March 31, 2004 Compared to March 31, 2003

Oil and natural gas sales. For the three months ended March 31, 2004, oil and natural gas sales revenue increased $393,379 to $1,200,400, compared to $807,021 for the same period during 2003. Oil sales increased $363,996 and natural gas sales increased $29,383. The increase in oil sales was the result of a sales volume increase of 10,193 barrels for the three months ended March 31, 2004 compared to the same period in 2003, and a 3% increase in the average realized per barrel oil price from $32.18 for the three months ended March 31, 2003 to $33.23 for the three months ended March 31, 2004. The increase in natural gas sales was the result of a sales volume increase of 8,411 Mcf for the three months ended March 31, 2004 compared to the same period in 2003, offset by a 9% decrease in the average realized natural gas price per Mcf from $4.40 for the three months ended March 31, 2003 to $4.00 for the three months ended March 31, 2004. The volume increase for crude oil and natural gas primarily resulted from $4 million of capital expenditures during 2003.

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Lease operating expenses. Our lease operating expenses increased from $242,071 or $9.53 per Boe for the three months ended March 31, 2003 to $316,290 or $8.54 per Boe for the three months ended March 31, 2004. 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 the three months ended March 31, 2003 and remained steady at 7% for the three months ended March 31, 2004. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states, and on the possibility that any state may raise its production tax.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased by $51,373 to $111,120 in the three months ended March 31, 2004, compared to the same period in 2003. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $2.35 per Boe during the three months ended March 31, 2003 to $3.00 per Boe during the three months ended March 31, 2004. The increased depreciation, depletion and amortization was the result of increased sales volume and an increase in estimated future development costs, which increases the per Boe depreciation, depletion and amortization rate.

General and administrative expenses. General and administrative expenses increased by $34,571 to $178,202 for the three months ended March 31, 2004. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer our growth, and $16,095 paid to our independent engineers for the preparation of our reserve analysis reports for the year ended December 31, 2003.

Interest expense (net of interest income). Interest expense decreased $750 to $9,113 for the three months ended March 31, 2004 when compared to the same period in 2003. The decrease was due to our earning interest on part of our available cash balance in order to offset a portion of the interest expense incurred.

Income tax expense. Our effective tax rate was 37% during the three months ended March 31, 2003 and remained steady at 37% for the three months ended March 31, 2004.

Net income. Net income increased from $174,506 for the three months ended March 31, 2003 to $309,641 for 2004. The primary reasons for this increase include higher crude oil prices between periods and an increase in volumes sold, partially offset by higher lease operating expense, income tax expense and general and administrative expenses due to our growth.

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 $4 million of capital expenditures during 2003.

Lease operating expenses. Our lease operating expenses increased from $594,863 or $8.94 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.

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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 $209,085 to $360,282 in 2003. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $2.27 per Boe during 2002 to $2.79 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 liability is discounted using a credit-adjusted risk-free rate of approximately 8.08%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted abandonment liability of $236,718, increased proved property cost by $217,878, and recognized a one-time cumulative effect charge of $11,813 (net of a related tax effect of $7,027). The effect of adopting this accounting principle was a $24,873 after tax decrease in net income during 2003.

Net income. Net income increased from $387,049 for 2002 before preferred stock dividends, to $809,498 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 11% increase in the average realized oil price from $23.45 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 37% increase in the average realized natural gas price from $1.95 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.

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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 $107,049 from $44,148 in 2001 to $151,197 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 $2.27 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 $(410,969) in 2002. The primary reasons were a $734,496 increase in preferred stock dividends and an $833,597 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 natural 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 (see, Certain Relationships and Related Transactions), our initial public offering of stock in 2001, and private equity offerings of our stock and warrants.

Credit Facility. On February 3, 2003, we established a $10,000,000 revolving credit facility with an initial borrowing base of $2,000,000. On December 31, 2003, we entered into an agreement that increased the revolving credit facility to $20,000,000 and increased the initial borrowing base to $4,000,000. On April 14, 2004, we changed financial institutions and canceled this credit facility.

On April 14, 2004, we established a new $15,000,000 credit facility with an $8,500,000 initial borrowing base. Any increases in the borrowing base are subject to written consent by the lender. The interest rate is a floating rate equal to the 30, 60 or 90 day LIBOR plus 2.25%, currently 3.42% per annum, and is payable monthly. Annual fees for the facility are 1/8 of one percent of the unused portion of the borrowing base. Amounts borrowed under the revolving credit facility are due in April 2007. The revolving credit facility is secured by our principal mineral interests. In order to obtain the revolving credit facility the $400,000 loans from our two officers were subordinated to the position of the lender. We are required under the terms of the credit facility to

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maintain a tangible net worth of $6,000,000, maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense and maintain a current asset to current liability ratio of 1-to-1 (not including the $2,000,000 bridge financing arrangement discussed below).

On May 7, 2004, we drew $8,008,440 under this revolving credit facility to fund the acquisition of the East Hobbs Unit. An additional $294,029 is reserved under the revolving credit facility as collateral for standby letters of credit issued to various states.

On April 14, 2004, we also entered into to a bridge financing arrangement for $2,000,000 from the same lender. On May 7, 2004, we borrowed $2,000,000 under the terms of the bridge financing arrangement to fund the acquisition of the East Hobbs Unit. The interest rate on the bridge financing arrangement is a floating rate equal to the 30, 60 or 90 day LIBOR plus 2.25%, currently 3.42% per annum, and is payable monthly. The bridge financing arrangement has been guaranteed by our Chairman and our President. Amounts borrowed under the bridge financing arrangement are to be paid on or before August 16, 2004.

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 partially 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 the remainder of 2004 are $6 million, to be used primarily for acquisitions to expand our property base. We expect to fund these expenditures from cash on hand, internally generated cash flow during the year 2004, from the proceeds of this offering and from borrowings under our credit facility, if required. In the event we are not successful in raising the anticipated funds from this offering, we nevertheless believe these capital expenditures 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 increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among others.

If we do not find suitable properties for acquisition, it is likely we will initiate further development of our existing properties. This development would be funded by internally generated cash flow, from a portion of the proceeds of this offering and from borrowings under our credit facility, if available. 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 somewhat 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 our refinancing activities associated with our acquisition of the East Hobbs Unit.

Year	Short-Term Debt	Long-Term Debt	Operating Lease	Total Cash Obligation
2004	$ 2,000,000	$	$ 15,300	$ 2,015,300
2005		400,000	20,400	420,400
2006				

2007		8,008,440		8,008,440
Total	$ 2,000,000	$ 8,408,440	$ 35,700	$ 10,444,140

Off-Balance Sheet Financing Arrangements

As of March 31, 2004 we had, and as of the date of this prospectus we have, no off-balance sheet financing arrangements.

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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 any 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.

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 1 to both our annual and interim financial statements included as a part of this prospectus.

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

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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 prospectus. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

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

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

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this prospectus 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 prospectus is based on estimates prepared by Lee Keeling and Associates, Inc., independent petroleum engineers, except for the Dodson Lease and the East Hobbs Unit which are based on our internal estimates. We have eliminated approximately 1.9 million BOE of reserves related to the Dodson lease which were classified as proved undeveloped in the December 31, 2003 estimate of reserves prepared by Lee Keeling and Associates, Inc. This revision was based upon a more comprehensive review of the engineering and geological data related to this lease currently available to us and the determination that until such data is supplemented (by information gathered from additional development activities on this lease or other sources), it is necessary to remove such reserves from the proved category. We have further eliminated approximately 3.6 million BOE of reserves which we had classified as proved upon our acquisition of the East Hobbs Unit in May 2004, for the same reasons.

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Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional properties are acquired. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made.

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

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

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

Effects of Inflation and Pricing

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

The amounts we have drawn under our current credit facility are subject to floating interest rates. Therefore, interest rate changes will impact future results of operations and cash flows.

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BUSINESS AND PROPERTIES

About Our Company

We are engaged in oil and natural gas exploitation, acquisition, development and exploration activities currently in the states of Oklahoma, Texas, New Mexico and Kansas. Our focus is on pursuing acquisitions of oil and gas properties that provide immediate cash flow as well as opportunities for further development, which we believe will generate attractive rates of return while maintaining a balanced portfolio of lower risk, long-lived oil and natural gas properties.

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 development 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 (present value of future net revenues before income taxes discounted at 10%) 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). On May 7, 2004, we completed the acquisition of an 82.2% working interest in a lease in Lea County, New Mexico (the East Hobbs Unit), with a net revenue interest of approximately 67.6%, with proved reserves of approximately 3.0 million Boe. With this acquisition, we estimate our total proved reserves to be approximately 10.6 million Boe. The acquisition cost of the East Hobbs Unit was approximately $10,000,000. With this acquisition, since our inception in August 2000, we have acquired leases on 11 producing properties at an aggregate cost of approximately $18.8 million, representing approximately 10.6 million Boe of proved reserves, and an average cost of $1.77 per Boe.

Following the acquisition of the East Hobbs Unit, we are closer to having a base of producing properties that we believe to be sufficient to fund the development phase of our business plan. However, we anticipate seeking one or two more acquisitions in 2004, prior to commencing a more aggressive development program.

We expect to further develop our properties through additional drilling. We have budgeted approximately $6 million for capital expenditures for the remainder of 2004, most of which is targeted for the acquisition of additional reserves. This budget will be financed from the proceeds of this offering, cash flow from operations and, if necessary, from drawing on our credit facility.

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 23% of our proved reserves are classified as proved developed producing properties. Approximately 1% of our proved reserves are classified as proved developed nonproducing, and approximately 76% are classified as proved undeveloped.

The following table summarizes our total net proved reserves and pre-tax PV10 value as of December 31, 2003. Additionally, the table summarizes the total net proved reserves and pre-tax PV10 value of the East Hobbs Unit, as of March 1, 2004.

Proved Developed and Undeveloped Reserves

Geographic Area	Oil (Bbl)	Natural Gas (Mcf)	Total (Boe)	Pre-Tax PV10 Value
Oklahoma	3,465,351	658,484	3,575,089	$ 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
East Hobbs San Andres Unit (New Mexico)	2,730,837	1,637,640	3,003,777	$ 38,702,806

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The Company currently leases its 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.

Business Strategy

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 14,273 gross (10,541 net) developed acres and operate essentially all of the net pre-tax PV10 value of our proved undeveloped reserves. In addition, as of May 7, 2004, we owned interests in approximately 2,615 gross undeveloped acres (2,106 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 these future exploitation activities from the cash flow generated by production. Our current strategy is to attempt to acquire approximately $6 million to $8 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.

If we are not successful in raising the anticipated funds in this offering, we may not be able to secure sufficient capital (from borrowings or otherwise) to acquire $6 million to $8 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 such 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. From August 2000 through May 2004, we acquired 11 producing leases at an aggregate cost of approximately $18.8 million, representing approximately 10.6 million Boe of proved reserves (at an average cost of $1.77 per Boe).

Focusing on Operated Properties with Additional Development Potential. We have historically acquired properties which have existing production and which are capable of supporting additional development, exploitation and exploration potential. In pursuing such acquisitions, our focus has been on acquiring properties we can operate so that we can better control the timing and implementation of capital spending associated with such additional development. We intend to continue to acquire both operated and non-operated interests to the extent they meet 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 (which includes only oil and gas production costs) per

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Boe averaged $8.92 and general and administrative costs averaged $4.33 per Boe produced. For the three months ended March 31, 2004, our lease operating expense per Boe averaged $8.54 and general and administrative costs averaged $4.82 per Boe.

Proposed Acquisition Activity

Assuming the successful completion of this offering, we will have a capital budget of approximately $6 million for the remainder of 2004. We expect to budget this amount for the acquisition of additional oil and natural gas properties. In addition to utilizing a portion of the proceeds from this offering, we anticipate using a portion of our cash flow from operations, and potentially to draw on our credit facility, if necessary, for these acquisitions.

It is our current intention to continue to focus our acquisition strategy on properties in our present areas of operation Oklahoma, Texas, New Mexico and Kansas. Our business strategy is to expand our base of proven properties until such time as we believe the existing production from our current properties and new acquisitions will be sufficient to fund further development. We believe the acquisition of additional properties utilizing our proposed capital budget for the remainder of this year will enable us to achieve our critical mass of producing properties. However, this is an estimate only, and could change depending on a variety of factors, including fluctuating oil and gas prices, increasing prices of acquisition targets, and the particular mix of reserves on properties that we may acquire. While it is our goal to acquire these properties during the remainder of 2004, and thereafter initiate our development program by utilizing cash flow from producing properties so acquired, if we are not successful in finding properties that satisfy our acquisition criteria, it is possible that we may later determine that a larger portion of the proceeds of this offering would be better utilized to commence exploitation and development opportunities on properties we already own. Factors such as a continued significant increase in oil and natural gas prices (which could have the effect of driving the cost of new acquisitions above what we are willing to pay) may also lead to our determination that it is more economically feasible to begin our drilling and exploration program (although possibly at a somewhat reduced level) sooner than we currently anticipate.

Proved Reserves as of December 31, 2003

Our 7,618,283 Boe of proved reserves as of December 31, 2003, which consist of approximately 92% oil and 8% natural gas, are summarized below, 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, 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 23% 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 1% and 76%, 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, 21.5% or $14.4 million of which is associated with the PDP reserves. An additional $852,000 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. While our reserve report includes $13.6 million of capital expenditures for development activity, it is our intent to defer undertaking extensive additional development activity until such time that we have expanded our portfolio of producing properties, so that we will be able to utilize our cash flow from existing production to finance such future development activities. We presently anticipate that we will be in a position to begin such development activities from internally generated cash flow in the first quarter of 2005, and to fully develop our interests over the ensuing 18 to 24 months.

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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 (000 s)	Future Capital Expenditures (000 s)
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

On May 7, 2004, we completed the acquisition of the East Hobbs Unit in New Mexico. The proved reserves associated with this acquisition, as of March 1, 2004, are described in the following table:

	Oil (Bbl)	Natural Gas (Mcf)	Total (Boe)	% of Total Proved[(1)]	Pre-Tax PV-10 (000 s)	Future Capital Expenditures

						(000 s)
PDP	509,486	447,839	584,126	19%	$ 8,574	$
PDNP	339,365	236,436	378,771	13%	5,179	66
PUD	1,881,986	953,365	2,040,880	68%	24,950	4,286
	2,730,837	1,637,640	3,003,777	100%	$ 38,703	$ 4,352

(1) This percentage is computed only for the East Hobbs Unit, and is not combined with our proved reserves as of December 31, 2003, since our reserve estimate for the East Hobbs Unit is as of March 1, 2004.

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

As of the date of this prospectus we have not converted any of our reserves that are classified as proved undeveloped to proved developed producing . The approximate $1.6 million we have spent in development activities to date have been spent on existing wells or on further development of properties already classified as

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developed and producing. The following table indicates projected reserves (including estimated reserves on the East Hobbs Unit) that we currently estimate will be converted from proved undeveloped to proved developed, as well as the estimated costs per year involved in such development. The timing of our development schedule represented below may differ from our reserve reports as of December 31, 2003, due primarily to our utilization of capital resources in connection with the acquisition of the East Hobbs Unit, that would have otherwise been potentially available for development operations.

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

Year	Estimated Oil Reserves Developed (Bbls)	Estimated Gas Reserves Developed (Mcf)	Total BOE	Estimated Development Costs
2004	169,681	117,907	189,332	$ 502,648
2005	3,128,978	1,739,397	3,418,878	$ 6,575,858
2006	4,052,973	892,077	4,201,642	$ 10,881,785
	7,351,632	2,749,381	7,809,852	$ 17,960,291

Production

Our estimated average daily production for the month of March, 2004, is summarized below. This table indicates the percentage of our estimated March, 2004 average daily production of 406 Boe/d attributable to each state and to oil versus natural gas production. The table does not include production from the East Hobbs Unit which we acquired in May 2004.

Average Daily Production (March 2004): 406 Boe/d

State	Average Daily Production	Oil	Natural Gas
Oklahoma	43.49%	39.33%	4.16%
Texas	26.34%	24.90%	1.44%
New Mexico	30.17%	26.96%	3.21%
Kansas	%	%	%
Total	100%	91.19%	8.81%

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 this 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.

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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. There was no production from this lease in March, since it has been shut-in since December. 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. In March 2004, we produced 2,088 Boe from this lease.

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. In March 2004, we produced 2,367 Boe from this lease.

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. In March 2004, we produced 737 Boe from these leases. 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. In March 2004 this lease produced 283 Boe.

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

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the displaced oil to adjacent production wells. This potential waterflood project (and the estimated $1 million cost thereof) is included as PUD in our reserve 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. In March 2004, we produced 2,108 Boe from this lease.

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. In March 2004 we produced 120 Boe from this property.

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 Holdings, 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. In March 2004, we produced 1,207 Boe from this lease.

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. In March 2004, we produced 2,757 Boe from this lease.

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. In March 2004, we produced 1,040 Boe from this lease.

The North Benson Queen Unit Waterflood will require additional volumes of injection 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 of 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

.East Hobbs San Andres Unit Lea County, New Mexico. On May 7, 2004, we acquired an 82.2% working interest and a 67.6% net revenue interest in this lease consisting of approximately 920 acres, which currently has 20 operating wells. The remaining working interest is owned by unaffiliated parties. We acquired this interest from Enerquest Resources, LLC, an unaffiliated company. We currently anticipate this lease can support up to 12 additional wells, to further develop remaining primary reserves and as a part of the development of the future secondary recovery project. The lease is currently held by production. In March 2004, this lease produced 6,369 Boe.

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

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interest (80% of the net revenue interest) in the well and related oil and gas until payout of all costs of drilling, equipping, completing 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.

In January 2004 we drilled and completed a second well on this acreage at a cost of approximately $113,000. The well was successful and is pending connection to the pipeline, and we believe one additional well may be drilled on this property, which is included in our estimate of PUD.

In 2004 we also leased an additional 480 acres that offset this property. Of the original 800 acres and additional 480 acres under lease, 640 acres are held by production and the lease of the remaining 640 acres expires in May 2007, unless then held by production. There was no production from this lease in March 2004.

Beals Prospect Comanche County, Kansas. In July 2003 we acquired a 100% working interest and an 80.5% net revenue interest in this lease, consisting of 1,560 acres. This lease was acquired from 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. There was no production from this lease in March 2004. This lease will expire in April of 2006 if not then held by production.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at May 7, 2004 (including the East Hobbs Unit), 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	4,960	3,418	39	32	4,999	3,450

Kansas	160	128	2,200	1,773	2,360	1,901
Total	14,273	10,541	2,615	2,106	16,888	12,647

Production History

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

	Year Ended December 31,			For the Three Months Ended March 31,
	2001	**2002**	**2003**	**2004[1]**
Oil production (Bbls)	12,895	58,717	117,646	33,783
Natural gas production (Mcf)	4,776	46,819	67,329	19,323
Total production (Boe)	13,691	66,520	128,868	37,003
Daily production (Boe/d)	38	182	353	407
Average sales prices[2]:				
Oil (per Bbl)	$ 23.45	$ 26.09	$ 29.06	$ 33.24
Natural gas (per Mcf)	1.95	2.67	3.67	4.00
Total (per Boe)	22.77	24.91	28.44	32.44
Average production cost (per Boe)	$ 7.81	$ 8.94	$ 8.92	$ 8.54

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(1) This amount includes production from wells existing as of March 31, 2004. It does not include any production for the East Hobbs Unit in New Mexico.
(2) We do not undertake any hedging activities that would impact the pricing reflected.

In December 2003, we temporarily shut-in a well on the Casey lease in Oklahoma that accounted for approximately 11% of our natural gas production in 2003. This well was shut-in because it was no longer economical to produce from that formation. We plan to explore two new formations in this well in 2004. The remaining natural gas production comes from our wells that are primarily oil producers.

Productive Wells

The following table presents our ownership at May 7, 2004, in productive oil and natural gas wells by region (a net well is our percentage ownership of a gross well).

	Oil Wells		Natural Gas Wells (1)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oklahoma	23	16.53			23	16.53
Texas	25	20.00			25	20.00
New Mexico	84	56.94			84	56.94
Kansas						
Total	132	93.47			132	93.47

(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 but is shut-in pending a pipeline connection, 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 but is shut-in pending a pipeline connection. In 2003 we participated in drilling one gross well (0.8 net well) in Kansas, which was plugged and abandoned as a dry hole. In January 2004 we drilled and completed a well (0.8 net well) in Kansas, which was successful and is pending connection to the pipeline.

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 costs capitalized during the years ended December 31, 2001, 2002 and 2003 related to our oil and natural gas producing activities are shown below.

	For the Years Ended December 31,			For the Three Months Ended March 31,	
	2001	2002	2003	2003	2004
Acquisition of proved properties	$ 1,032,786	$ 2,659,832	$ 2,470,821	$	$
Acquisition of unproved properties			147,000		
Exploration costs			326,410		
Development costs	551,859	579,153	849,864	50,219	296,620
Acquisition of support and office equipment		29,388			
Asset retirement costs recognized upon adoption of SFAS No. 143			221,218		
Total Costs Incurred	$ 1,584,645	$ 3,268,373	$ 4,015,313	$ 50,219	$ 296,620

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Reserve Quantity Information

Our estimates of proved reserves and related valuations as of December 31, 2003 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, and the East Hobbs Unit in Lea County, New Mexico, which were based on our internal estimates, all in accordance with the provisions of SFAS 69, Disclosures About Oil and Gas Producing Activities. We have eliminated approximately 1.9 million BOE of reserves related to the Dodson lease which were classified as proved undeveloped in the December 31, 2003 estimate of reserves prepared by Lee Keeling and Associates, Inc. This revision was based upon a more comprehensive review of the engineering and geological data related to this lease currently available to us and the determination that until such data is supplemented (by information gathered from additional development activities on this lease or other sources), it is necessary to remove such reserves from the proved category. We have further eliminated approximately 3.6 million BOE of reserves which we had classified as proved upon our acquisition of the East Hobbs Unit in May 2004, for the same reasons. 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	1,636,145
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	4,113,936	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

The estimates shown above as of December 31, 2003 do not include the reserve estimates associated with the East Hobbs Unit we recently acquired. Total estimated reserves associated with the East Hobbs Unit as of March 1, 2004 were 2,730,837 barrels of oil, and 1,637,640 Mcf of gas. These reserves were estimated by us and are not included in the report of our independent engineer referred to above.

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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	750,463	1,580,521
Undeveloped	352,452	3,363,473	5,469,646
Total	494,823	4,113,936	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	3,701,326	5,768,972
Total	988,219	4,645,230	7,618,283

The proved oil and natural gas reserves associated with the East Hobbs Unit as of March 1, 2004 are shown below.

Oil (Bbls):	
Developed	848,851
Undeveloped	1,881,986
Total	2,730,837
Natural Gas (Mcf):	
Developed	684,275
Undeveloped	953,365
Total	1,637,640
Total (Boe):	
Developed	962,897
Undeveloped	2,040,880
Total	3,003,777

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)	(8,786,870)
End of the Year	$ 27,997,824	$ 45,006,097

Marketing and 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, Plains Marketing, L.P., Navajo Refining Company and Sunoco, Inc., (all unaffiliated parties) were responsible for generating 81% or more of our total oil and natural gas sales. However, we believe that the loss of any one of these customers would not materially impact our business, because we could readily find other purchasers for our oil and gas as produced.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Our credit facility is also secured by a first lien on substantially all of our assets. We do not believe that any of these burdens materially interferes with the use of our properties in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel or have title reviewed by certified landmen only when we acquire producing properties or before commencement of drilling operations.

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Competition

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

Current competitive factors in the domestic oil and gas industry are unique. The actual price range of crude oil is largely established by major international producers. Pricing for natural gas is more regional. Because the current domestic demand for oil and gas exceeds supply, we believe there is little risk that all our 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 currently committed to use the services of the existing gathering companies in our present areas of production. This potentially gives such gathering companies certain short-term relative monopolistic powers to set gathering and transportation costs, because obtaining the services of an alternative gathering company would require substantial additional costs (since an alternative gathering company would be required to lay new pipeline and/or obtain new rights of way to any lease from which we are selling production).

Regulation

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. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. 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

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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. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act. The Decontrol Act removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

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. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. 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.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect. While most major aspects of Order No. 637 have been upheld on judicial review, certain issues such as capacity segmentation and right of first refusal are pending further consideration by the FERC. We cannot predict what action the FERC will take on these matters in the future, or whether the FERC s actions will survive further judicial review.

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. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. 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.

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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 Regulations

General. 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 (EPA). 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 EPA and other governmental agencies that would govern significant spills, blow-outs, or uncontrolled emissions. In Oklahoma, Texas, New Mexico and Kansas specific oil and gas regulations apply to the drilling, completion and operations of wells, and the disposal of waste oil and salt water. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency.

All of these laws and regulations often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties or may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit project siting, construction or drilling activities on certain lands laying within wilderness, wetlands, ecologically sensitive and other protected areas, require remedial action to prevent pollution from former operations, such as plugging abandoned wells or closing pits, and impose substantial liabilities for pollution resulting from our operations. The EPA and analogous state agencies may delay or refuse the issuance of required permits or otherwise include onerous or limiting permit conditions that may have a significant adverse impact on our ability to conduct operations. The regulatory burden on the oil and natural gas industry increases the cost of doing business and consequently affects its profitability.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general. While we believe that we are in substantial compliance with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future.

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The environmental laws and regulations which have the most significant impact on the oil and natural gas exploration and production industry are as follows:

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as CERCLA or Superfund, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of a disposal site or sites where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. A liability is joint and several where more than one party is responsible for the damage, and the responsible parties may be sued (and any ultimate recovery collected) either separately from any responsible party or collectively from more than one responsible party, at the option of the injured party. This means any single responsible party could be liable for the entire amount of damage (although such party may have a right against other responsible parties for their proportionate part of any damages). In the course of our ordinary operations, we may generate waste that may fall within CERCLA s definition of a hazardous substance. Consequently, we may be jointly and severally liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed or released.

We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under, or from the properties owned or leased by us or on, under, or from other locations where these wastes have been taken for disposal. In addition, many of these owned and leased properties have been operated by third parties whose management and disposal of hydrocarbons and wastes were not under our control. Similarly, the waste disposal facilities where wastes are sent are also often operated by third parties whose waste treatment and disposal practices may not be adequate. While we only use what we consider to be reputable disposal facilities, we might not know of a potential problem if the disposal occurred before we acquired the property. Our properties, adjacent affected properties, the disposal sites, and the waste itself may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators or other third parties;
- to clean up contaminated property, including contaminated groundwater; or
- to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are associated with any Superfund site and we have not been notified of any claim, liability or damages under CERCLA.

Oil Pollution Act. The Oil Pollution Act of 1990, also known as OPA, and regulations issued under OPA impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA s financial responsibility and other operating requirements will not have a material adverse effect on us.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, also known as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a generator or transporter of hazardous waste or an owner or operator of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy and thus we are not required to comply with a substantial portion of RCRA s requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or state agencies as solid waste. In addition, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes, and waste compressor oils, may be regulated as hazardous waste. Although we do not believe the current costs of managing our wastes as they are presently classified to be significant, any repeal or modification of the oil and natural gas exploration and production exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses.

Clean Air Act. The Clean Air Act, also known as CAA, restricts the emission of air pollutants from many sources, including oil and natural gas operations. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. In addition, more stringent regulations governing emissions of toxic air pollutants are being developed by the EPA, and may increase the costs of compliance for some facilities. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold or have applied for all necessary permits for our operations.

Clean Water Act. The Federal Water Pollution Control Act of 1972, or the Clean Water Act, imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. In furtherance of the Clean Water Act, the EPA promulgated the Spill Prevention, Control, and Countermeasure, or SPCC, regulations, which require certain oil containing facilities to prepare plans and meet construction and operating standards. The SPCC regulations were revised in 2002 and will require updated SPCC plans beginning in early 2004. We believe that we have all permits required and our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution and that updating of our SPCC plans will not have a significant impact on our operations.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the re-injection of brine produced and separated from oil and natural gas production. In our industry, underground injection not only allows us to economically dispose of produced water, but if injected into an oil bearing zone, it can increase the oil production from such zone. The Safe Drinking Water Act of 1974 establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. (If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed at an approved hazardous waste facility.) We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

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Endangered Species Act. Certain flora and fauna that have officially been classified as threatened or endangered are protected by the Endangered Species Act. This law prohibits any activities that could take a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed, or expensive mitigation might be required.

Migratory Bird Act. If migratory birds are injured or killed because of improper facility construction or maintenance methods that result in such birds being exposed to oil or other related substances, the operator of that facility is subject to substantial fines. We frequently inspect the properties we operate to make sure that the screens covering open top tanks and pits are in good condition and that any oil film on the water contained in them is promptly removed.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the National Environmental Policy Act, require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The National Environmental Policy Act requires the Department of Interior and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement.

Abandonment Costs. One of the responsibilities of owning and operating oil and natural gas properties is paying for the cost of abandonment. Effective January 1, 2003, companies are required to reflect abandonment costs as a liability on their balance sheets in the period in which it is incurred. See Management s Discussion and Analysis of Financial Condition and Results of Operations New Accounting Policies.

Employees

As of March 31, 2004, we had eight 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.

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.

Environmental and Safety

In the opinion of our management, our operations comply in all material respects with applicable environmental legislation and regulations. We believe that compliance with existing federal, state, and local laws, rules, and regulations regulating the discharge of materials into the environment or otherwise relating to the protection of the environment will not have any material effect upon our capital expenditures, earnings or competitive position.

There have been no safety-related violations, or worker s compensation claims in 2002 or 2003. In addition, there have been minimal vehicle insurance claims during the last two years.

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MANAGEMENT

Executive Officers and Directors

The following table sets forth information regarding our executive officers, certain other officers and directors as of March 31, 2004:

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. Specifically, in August 2000 Mr. Rochford co-founded Arena Resources, Inc. Prior to that, from June, 1997 until founding Arena, Mr. Rochford primarily devoted his time to individual oil and gas acquisitions and development. From 1990 until June 1997 Mr. Rochford served as a director and officer of a public company known as Magnum Petroleum, Inc. (Magnum) which is listed on the New York Stock Exchange. Mr. Rochford was a co-founder of Magnum. Between Magnum s founding in 1990 until August 1995, Mr. Rochford was a director and CEO of Magnum. In August 1995 Magnum acquired Hunter Resources, Inc., and Mr. Rochford served as Chairman of the Board of the combined companies from that time until June, 1997.

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

Mr. McCabe, 71, co-founded Arena with Mr. Rochford in August 2000. Between January 1997 and forming Arena, Mr. McCabe was involved as an independent investor and developer of oil and natural gas properties. From 1990 through December 1996 Mr. McCabe served as an officer and director of Magnum Petroleum, Inc., which he co-founded with Mr. Rochford. When Magnum acquired Hunter Resources, Inc. in August 1995, Mr. McCabe also served as a director of that company until December 1996.

William R. Broaddrick Vice President and Chief Financial Officer.

Mr. Broaddrick, 26, joined Arena as chief accountant in September 2001, and effective February 1, 2002, assumed responsibilities as Vice President and Chief Financial Officer. Prior to joining us, Mr. Broaddrick was employed in 2000 by Duke Energy Field Services, LLC, performing state production tax functions. From 1997 to 2000 Mr. Broaddrick was employed by Amoco Production Company, performing lease revenue accounting and state production tax regulatory reporting functions.

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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

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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 under the rules of the SEC adopted pursuant to requirements of the Sarbanes-Oxley Act of 2002 (see the biographical information for each of Messrs. Kemendo and Woodrum, infra, in this Management section). 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.

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. Except as set forth in the table below, no other compensation was paid to such officers.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation		Long-Term Compensation Awards
		Salary ($)(1)	Bonus ($)	Securities Underlying Options(2)
Lloyd T. Rochford	2001	$ 24,500		
	2002	$ 36,000		
President and Chief Executive Officer	2003	$ 36,000		$ 229,742
Stanley M. McCabe	2001	$ 24,500		
	2002	$ 36,000		
Chairman of the Board	2003	$ 36,000		$ 229,742
William R. Broaddrick	2001	$ 16,334	$ 3,000	
	2002	$ 45,000	$ 6,000	
Vice President, Chief Financial Officer	2003	$ 47,927		$ 459,484

(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.

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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%	$ 3.70	$ 4.35	10/1/08
Charles M. Crawford	50,000	5%	$ 3.70	$ 4.35	10/1/08
Chris V. Kemendo, Jr.	50,000	5%	$ 3.70	$ 4.35	10/1/08
Clayton E. Woodrum	50,000	5%	$ 4.80	$ 5.64	2/12/09
Phillip W. Terry	250,000	25%	$ 3.70	$ 4.35	10/1/08
Raymond H. Estep	100,000	10%	$ 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. In addition, no options have been exercised as of the date of this prospectus. 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 fill the vacant board position.

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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 ($)	Number of Unexercised Securities Underlying Options/SARs at FY-End (#) Exercisable/ Unexercisable	Value of Unexercisable In-The-Money Options/SARs at FY-End ($) 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 the securities authorized for issuance under 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	-0-

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STOCK OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth, as of the date hereof, 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 Prior to this Offering		Shares of Common Stock Beneficially Owned After this Offering	
Name	**Number**	**Percent**	**Number**	**Percent**
Lloyd T. Rochford	1,312,600(1)	18.3%	1,312,600(1)	15.2%
Stanley M. McCabe	1,163,000(2)	16.2%	1,163,000(2)	13.5
William R. Broaddrick	54,500(3)	*	54,500(3)	*
Charles M. Crawford	10,000(4)	*	10,000(4)	*
Chris V. Kemendo, Jr.	10,100(5)	*	10,100(5)	*
Clayton E. Woodrum	10,000(6)	*	10,000(6)	
All directors and executive officers as a group (6 persons)	2,560,200(7)	35.6%	2,560,200	29.7%

(1) Includes 25,000 shares issuable upon the exercise of stock options that are currently exercisable.
(2) Includes 25,000 shares issuable upon the exercise of stock options that are currently exercisable.
(3) Includes 50,000 shares issuable upon the exercise of stock options that are currently exercisable.
(4) Includes 10,000 shares issuable upon the exercise of stock options that are currently exercisable.
(5) Includes 10,000 shares issuable upon the exercise of stock options that are currently exercisable.
(6) Includes 10,000 shares issuable upon the exercise of stock options that are exercisable within 60 days.
(7) Includes 130,000 shares issuable upon the exercise of stock options that are currently exercisable or 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 7,192,097 shares of our common stock outstanding immediately prior to the completion of this offering, and the issuance of 1,450,000 shares as a part of the units as a result of this offering. In addition, the underwriters have an option to purchase up to 217,500 additional units (consisting of 217,500 shares and warrants to acquire an additional 217,500 shares) to cover over-allotments, if any, incurred in connection with this offering. None of such shares have been taken into account in the calculation of shares beneficially owned after the offering. The percentage ownership calculations above also assume that no officer or director acquires any units in the offering. However, there is no prohibition on any officer or director acquiring units as a part of the public offering. Each of the officers and directors listed above has agreed, not to sell or transfer any of our common stock for 12 months after the date of this prospectus. See, Shares Eligible for Future Sale.

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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 interest 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 July 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). Messrs. Rochford and McCabe have also guaranteed our $2 million bridge loan we negotiated in connection with the acquisition of the East Hobbs Unit.

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 our 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 a member of our board and forfeited all stock options (none of which had vested) which he had been granted by reason of his position as a board member.

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DESCRIPTION OF SECURITIES

The following is a summary of all material characteristics of our capital stock and articles of incorporation and by-laws. However, the summary does not purport to be complete and is qualified in its entirety by reference to the provisions of Nevada corporate law and to our articles of incorporation and by-laws, which are filed as exhibits to the registration statement of which this prospectus is a part.

Units

We will issue 1,450,000 units, with each unit consisting of one share of our common stock and one warrant to purchase one share of our common stock. The units will have no rights (i.e., voting, redemption, etc.) independent of the rights existing in the common stock and warrants which form the unit. Until the units are divided into their separate components of one share of common stock and one warrant, only the units will trade on the American Stock Exchange (together with our currently issued shares of common stock that trade on the American Stock Exchange). Each unit will be divided into its separate component of one share of common stock and one warrant upon the earlier of one year from the date of this prospectus, or upon thirty (30) days prior written notice from us. However, we will not allow separation of the units until the earlier to occur of 60 days immediately following this offering or the exercise by the underwriters of the entire over-allotment option. Following the separation of the units, the shares of common stock will trade on the American Stock Exchange (and will be indistinguishable from our common stock currently trading on such exchange), and the warrants will trade separately from the common stock on such exchange. The units will cease to exist at that time.

Common Stock

We are authorized to issue up to 100,000,000 shares of our common stock, $0.001 par value. There are 7,192,097 shares of our common stock issued and outstanding as of the date of this prospectus. All shares of our common stock have equal voting rights and, when validly issued and outstanding, have one vote per share in all matters to be voted upon by stockholders. The shares of common stock have no preemptive, subscription, conversion or redemption rights and may be issued only as fully paid and non-assessable shares. Cumulative voting in the election of directors is not allowed, which means that the holders of a majority of the outstanding shares represented at any meeting at which a quorum is present will be able to elect all of the directors if they choose to do so and, in such event, the holders of the remaining shares will not be able to elect any directors. On liquidation, each common stockholder is entitled to receive a pro rata share of the assets available for distribution to holders of common stock

We have no stock option plan or similar plan which may result in the issuance of stock options, stock purchase warrants, or stock bonuses other than our executive stock option plan. Our executive stock option plan was approved in 2003, pursuant to which an aggregate of 1,000,000 shares of common stock have been reserved for issuance. Currently, we have granted options for all 1,000,000 shares to our officers, directors and key employees under this plan. The average exercise price of the options is $3.76 per share.

We currently have outstanding warrants entitling the holders of the warrants to purchase up to 1,405,723 shares of common stock. 195,800 of theses warrants have an exercise price of $1.75 and expire June 28, 2005, another 50,000 warrants have an exercise price of $3.00 and expire July 15, 2006, and the remaining 1,159,923 warrants have an exercise price of $5.00 and expire September 30, 2005.

Warrants

Each warrant to be issued as a part of a unit pursuant to this offering will entitle the holder to purchase one share of common stock at an exercise price of $7.32 (120% of the public offering price of the unit) for a period of four years from the date hereof, subject to our redemption rights described below. The warrants will be issued pursuant to the terms of a warrant agreement between the warrant agent, Atlas Stock Transfer, Inc. and us. We

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have authorized and reserved for issuance the shares of common stock issuable on exercise of the warrants. The warrants are exercisable to purchase a total of 1,450,000 shares of our common stock unless the underwriters over-allotment option relating to the warrants is exercised, in which case the warrants are exercisable to purchase a total of 1,667,500 shares of common stock.

The warrant exercise price and the number of shares of common stock purchasable upon exercise of the warrants are subject to adjustment in the event of, among other events, a stock dividend on, or a subdivision, recapitalization or reorganization of, the common stock, or the merger or consolidation of us with or into another corporation or business entity.

Commencing one year from the date of this prospectus and until the expiration of the warrants, we may redeem all outstanding warrants, in whole but not in part, upon not less than 30 days notice, at a price of $.10 per warrant, provided that the closing bid price of our common stock equals or exceeds $9.76 (160% of the offering price of the units) for 20 consecutive trading days. The redemption notice must be provided not more than five business days after conclusion of the 20 consecutive trading days in which the closing bid price of the common stock equals or exceeds 160% of the offering price of the units. In the event we exercise our right to redeem the warrants, the warrants will be exercisable until the close of business on the date fixed for redemption in such notice. If any warrant called for redemption is not exercised by such time, it will cease to be exercisable and the holder thereof will be entitled only to the redemption price.

We must have on file a current registration statement with the SEC pertaining to the common stock underlying the warrants in order for a holder to exercise the warrants or in order for the warrants to be redeemed by us. The shares of common stock underlying the warrants must also be registered or qualified for sale under the securities laws of the states in which the warrant holders reside. We intend to use our best efforts to keep the registration statement current, but there can be no assurance that such registration statement (or any other registration statement filed by us covering shares of common stock underlying the warrants) can be kept current. In the event the registration statement covering the underlying common stock is not kept current, or if the common stock underlying the warrants is not registered or qualified for sale in the state in which a warrant holder resides, the warrants may be deprived of any value.

We are not required to issue any fractional shares of common stock upon the exercise of warrants or upon the occurrence of adjustments pursuant to anti-dilution provisions. We will pay to holders of fractional shares an amount equal to the cash value of such fractional shares based upon the then-current market price of a share of common stock.

The warrants may be exercised upon surrender of the certificate representing such warrants on or prior to the expiration date (or earlier redemption date) of such warrants at the offices of the warrant agent with the form of Election to Purchase on the reverse side of the warrant certificate completed and executed as indicated, accompanied by payment of the full exercise price in cash or by official bank or certified check payable to the order of us for the number of warrants being exercised. Shares of common stock issued upon exercise of warrants for which payment has been received in accordance with the terms of the warrants will be fully paid and nonassessable.

The warrants do not confer on the warrantholder any voting or other rights of our stockholders. Upon notice to the warrantholders, we have the right to reduce the exercise price or extend the expiration date of the warrants. Although this right is intended to benefit warrantholders, to the extent we exercise this right when the warrants would otherwise be exercisable at a price higher than the prevailing market price of the common stock, the likelihood of exercise, and the resultant increase in the number of shares outstanding, may impede or make more costly a change in our control.

Preferred Stock

We are authorized to issue up to a total of 10,000,000 shares of Class A preferred stock, $0.001 par value. The preferred shares are non-voting. The preferred shares are entitled to priority over the common shares in the

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payment of dividends and to distributions in liquidation. The rights, preferences and limitations of separate series of preferred stock may differ with respect to (i) the rate of dividends, (ii) terms of redemption or (iii) conversion rights as may be determined by our Board of Directors.

In 2001 and 2002 we sold 1,886,359 shares of our Class A preferred stock in a private offering. The Class A preferred stock was convertible into common shares from the date of issuance on a 1-for-1 ratio. The Class A preferred shares were automatically convertible into common shares if the closing price of the common shares was equal to or greater than $4.00 for 20 consecutive days. After one year, the Class A preferred shares were redeemable by the Company, subject to a 30-day notice, at $1.84 per share plus payment of any accrued dividends. The Class A preferred shares accrued dividends at the rate of $0.175 per share annually and were payable quarterly. The Class A preferred shares were non-voting and were entitled to priority over the common shares in the payment of dividends and in liquidation.

On July 30, 2002, our common stock was priced at or above $4.00 per share for the twentieth consecutive day. Accordingly, the 1,886,359 shares of Class A preferred stock were automatically converted into 1,886,359 shares of common stock on July 30, 2002. Therefore, there are currently no shares of preferred stock issued or outstanding, and we have no present plans to issue any shares of preferred stock.

Nevada Anti-Takeover Law and Charter and By-law Provisions

Depending on the number of residents in the state of Nevada who own our shares, we could be subject to the provisions of Sections 78.378 *et seq.* of the Nevada Revised Statutes which, unless otherwise provided in a company s articles of incorporation or by-laws, restricts the ability of an acquiring person to obtain controlling interest in the company in certain situations. Our articles of incorporation and by-laws do not contain any provision which would currently keep the change of control restrictions of Section 78.378 from applying to us.

We are subject to the provisions of Sections 78.411 *et seq.* of the Nevada Revised Statutes. In general, this statute prohibits a publicly held Nevada corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination or the transaction by which the person became an interested stockholder is approved by the corporation s board of directors and/or stockholders in a prescribed manner, or the person owns at least 85% of the corporation s outstanding voting stock after giving effect to the transaction in which the person became an interested stockholder. The term business combination includes mergers, asset sales and other transactions resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an interested stockholder is a person who, together with affiliates and associates, owns, or within three years did own, 10% or more of the corporation s voting stock. A Nevada corporation may opt out from the application of Section 78.411 *et seq.* through a provision in its articles of incorporation or by-laws. We have not opted out from the application of this section.

Apart from Nevada law, however, our articles of incorporation and by-laws do not contain any provisions which are sometimes associated with inhibiting a change of control from occurring (i.e., we do not provide for a staggered board, or for super-majority votes on major corporate issues).

Liability and Indemnification of Officers and Directors

Our articles of incorporation and by-laws provide that our directors and officers shall not be personally liable to us or our stockholders for damages for breach of fiduciary duty as a director or officer, except for liability for (a) acts of omissions which involve intentional or reckless conduct, fraud or a knowing violation of law, or (b) the payment of distributions in violation of Section 78.300 of the Nevada Revised Statutes.

Moreover, the provisions would apply to claims against a director for violations of certain laws, including federal securities laws. Our articles of incorporation and by-laws also contain provisions to indemnify our directors and officers to the fullest extent permitted by Nevada law. In addition, we may enter into indemnification agreements with our directors and officers. These provisions and agreements may have the practical effect in certain cases of eliminating the ability of stockholders to collect monetary damages from directors and officers. We believe that these contractual agreements and the provisions in our articles of incorporation and by-laws are necessary to attract and retain qualified persons as directors and officers.

Transfer Agent and Registrar

The transfer agent and registrar for our securities is Atlas Stock Transfer, Inc., 5899 South State St., Salt Lake City, Utah, 84107, telephone (801) 266-7151.

SHARES ELIGIBLE FOR FUTURE SALE

General

Upon completion of the offering, we will have outstanding 8,642,097 shares of our common stock, assuming the issuance of 1,450,000 units pursuant to the offering. Until each unit is divided into its separate component of one share of common stock and one warrant (which will occur on the earlier of one year from the date of this prospectus or upon thirty (30) days prior written notice from us), the units themselves will be freely tradable without restriction by persons other than our affiliates, as that term is defined under Rule 144 under the Securities Act of 1933 (the 1933 Act). Persons who may be deemed affiliates generally include individuals or entities that control, are controlled by or are under common control with us and may include our officers, directors and significant stockholders. After the units separate into common stock and warrants, each component will be freely tradable without restrictions (other than the same restrictions on affiliates, noted above).

Of the 8,642,097 shares of common stock outstanding after this offering (which include the 1,450,000 shares of common stock issued as a part of the units offered hereby), 2,299,300 shares will be freely tradable without restriction in the public market. The 1,450,000 shares included as part of the units will be freely tradable as a part of the units, until separated, after which such shares will be freely tradable apart from the warrants. The remaining 6,342,797 shares may be sold publicly only if registered under the 1933 Act or sold in accordance with an exemption from the registration requirements of the 1933 Act, such as Rule 144.

Under Rule 144, a stockholder, including an affiliate, who has beneficially owned our shares for at least one year, is entitled to sell, within any three-month period, a number of restricted shares not exceeding the greater of: (a) one percent of the then outstanding shares of our common stock (or approximately 86,000 shares expected to be outstanding immediately after this offering); or (b) the average weekly trading volume in our common stock during the four calendar weeks preceding the filing of the notice reporting the sale. Sales under Rule 144 are subject to limitations on the manner in which they may be sold, notice requirements and the availability of current public information about us. Rule 144(k) provides that a person who is not deemed our affiliate and who has beneficially owned our shares for at least two years, is entitled to sell such shares at any time under Rule 144 without regard to the limitations described above. We estimate that approximately 2,048,752 outstanding shares of our common stock fall in the category of shares that could be currently sold pursuant to the provisions of Rule 144(k). These shares do not include any of the shares which are subject to the lock-up agreements described below. In addition, we estimate that approximately 1,865,045 outstanding shares of our common stock may be sold in the future, under the provisions of Rule 144.

As of the date of this prospectus, there were options outstanding to purchase 1,000,000 shares of common stock. Options for 950,000 shares of common stock are exercisable upon the payment of the option price of $3.70 per share, and the remaining 50,000 options are exercisable at the option price of $4.80. All of the options vest at the rate of 20% per year from their issue date. Currently, options covering 190,000 of such shares are exercisable. Options covering an additional 10,000 shares are exercisable within the next 60 days. As of the date of this prospectus we also had warrants outstanding to purchase 1,405,723 shares of our common stock with a weighted average exercise price of $4.47.

Sales of substantial amounts of common stock in the open market, or the perception that those sales could occur, could adversely affect prevailing market prices and could impair our ability to raise capital in the future through the sale of our equity securities.

Our officers and directors and persons owning 5% or more of our outstanding common stock have agreed, pursuant to lock-up agreements relating to the transfer of shares of our common stock, that they will not sell, transfer, hypothecate or convey any of the 2,425,600 shares of common stock they now own or shares of our common stock underlying derivative securities they currently own, by registration or otherwise, for a period of 12 months from the date of this prospectus, without the prior written consent of the representatives of the underwriters. The representatives of the underwriters have informed us that they have no current intentions of releasing any shares subject to the aforementioned lock-up agreements. Any determination by the representatives of the underwriters to release any shares subject to the lock-up agreements would be based on a number of factors at the time of determination, including the market price and trading volumes of the common stock, the liquidity of the trading market for the common stock, general market conditions, the number of shares proposed to be sold, and the timing, purpose and terms of the proposed sale.

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UNDERWRITING

Subject to the terms and conditions of the underwriting agreement, the underwriters named below, for which Neidiger, Tucker, Bruner, Inc. and Lane Capital Markets are acting as the underwriters co-representatives, have agreed to purchase from us the number of units set forth opposite their names, and will purchase the units at the public offering price, less the underwriting discount set forth on the cover page of this prospectus:

Underwriter	Number of Units
Neidiger, Tucker, Bruner, Inc	385,000
Lane Capital Markets	385,000
vFinance Investments, Inc.	200,000
SW Bach & Company	120,000
JP Turner & Company	80,000
Maxim Group LLC	80,000
Investors Capital Corporation	80,000
Capital West Securities, Inc.	40,000
Pali Capital, Inc.	40,000
Source Capital Group, Inc.	40,000
Total	1,450,000

Lane Capital Markets was formed in June 2001. Lane Capital Markets was registered with the NASD and the SEC as a broker-dealer in February 2002. Its principal business functions include providing advice on mergers, acquisitions, private placements and underwriting initial and secondary public offerings. Lane Capital Market s managing partner, John D. Lane, has been involved in the securities industry in various capacities since 1969. Mr. Lane participated in the 1993 initial public offering of securities by Magnum Petroleum, Inc. (which was co-founded by Messrs. Rochford and McCabe). In addition, Mr. Lane personally owns 25,000 shares of our common stock. The underwriting agreement provides that the underwriters obligations are subject to conditions precedent and that the underwriters are committed to purchase all units offered hereby (other than those covered by the over-allotment option described below) if the underwriters purchase any units. Among the conditions that must be satisfied before the underwriters are obligated to purchase the units, are: (i) the registration statement (of which this prospectus is a part) shall have been declared effective under the Securities Act of 1933; (ii) we shall have received a favorable opinion of our counsel regarding certain corporate matters, including the due issuance of the units and underlying common stock and warrants, and approval for listing the units on the American Stock Exchange; and (iii) all of the representations and warranties which we provide in the underwriting agreement are true and accurate.

The representatives have advised us that the underwriters propose to offer the units directly to the public at the public offering price set forth on the cover page of this prospectus, and that they may allow to certain dealers that are members of the National Association of Securities Dealers, Inc., concessions not in excess of $0.24. After the initial public distribution, the prices of the units may change as a result of market conditions. No change in the terms will change the amount of proceeds to be received by us as set forth on the cover page of this prospectus. The representatives have further advised us that the underwriters do not intend to confirm sales to any accounts over which any of them exercise discretionary authority.

The representatives of the underwriters have informed us that they do not intend to use any means of distributing or delivering this prospectus other than by hand or the mail. They do not intend to make any delivery of the prospectus by electronic means, and further we do not intend to use any form of prospectus other than this printed form (i.e., we will not utilize CD-ROM, videos or other means to display this prospectus). Additionally, apart from retrieval via the SEC s EDGAR system, we do not intend to make this prospectus available on our web-site or any third-party website over the Internet.

We have agreed to pay the representatives an aggregate nonaccountable expense allowance of 2.9% of the aggregate public offering price of the units offered, including the price of units sold on exercise of the

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over-allotment option. We have paid $70,000 of the nonaccountable expense allowance to the representatives. We have also agreed to pay all expenses in connection with qualifying the units offered hereby for sale under the laws of such states as the representatives may designate.

We have granted the underwriters options, exercisable for 60 days after the date of this prospectus, to purchase up to 217,500 additional units (entitling the underwriters to purchase up to 217,500 shares of common stock and to 217,500 additional warrants) at the same prices as the initial units are offered. The underwriters may purchase the units solely to cover over-allotments, if any, in connection with the sale of units offered hereby. If the over-allotment options are exercised in full, the total public offering price, underwriting discounts, and expense allowance and proceeds to us will be $10,171,750, $1,108,721 and $9,063,029, respectively. The expenses of this offering are estimated to be $450,000.

Our underwriters may engage in over-allotments, stabilizing transactions, syndicate short covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934. Stabilizing transactions permit bids to purchase our securities so long as the stabilizing bids do not exceed a specified maximum. Penalty bids permit our underwriters to reclaim a selling concession from a syndicate member when our securities originally sold by such selling group member are repurchased in the open market by the underwriters.

Over-allotments, or short sales, consist of sales by underwriters of a greater number of securities than they are required to purchase in an offering. In connection with this offering, our underwriters may make over-allotments, or short sales, of the units and may engage in syndicate short covering transactions, consisting of purchases of units on the open market, to cover positions created by short sales.

Covered short sales are sales made in an amount not greater than any over-allotment options for the underwriters to purchase additional securities in an offering. Underwriters may close out any covered short position by either exercising an over-allotment option or purchasing securities in the open market. In determining the source of securities to close out a covered short position in an offering, underwriters will consider, among other things, the price of the securities available for purchase in the open market as compared to the price at which they may purchase the securities through an over-allotment option.

Naked short sales are short sales of securities in excess of over-allotment options. Underwriters must close out any naked short positions by engaging in syndicate short covering transactions, purchasing securities in the open market. Underwriters are more likely to create naked short positions if they are concerned that, after pricing, there may be downward pressure on the open market price of the securities, thus adversely affecting investors who purchased in the offering.

Similar to other purchase transactions, syndicate short covering transactions, in which underwriters purchase securities in the open market to cover short sales, may have the effect of raising or maintaining the market price of securities or preventing or retarding a decline in the market price of securities.

In this offering, any syndicate short covering transactions, stabilizing transactions and penalty bids in which the underwriters engage may cause the price of the units to be higher than they would otherwise be in the absence of such transactions. These transactions may be effected on the American Stock Exchange or otherwise and, if commenced, may be discontinued at any time.

Neither we nor the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the prices of the units. In addition, neither we nor any of the underwriters makes any representation that the underwriters will engage in such transactions or that such transactions, once commenced, will not be discontinued without notice.

Our officers, directors and beneficial holders of 5% or more of our outstanding shares of common stock have agreed, pursuant to lock-up agreements relating to the transfer of shares of our common stock, that they will not sell, transfer, hypothecate or convey any of our shares of common stock by registration or otherwise for a period of 12 months from the date of this prospectus without the prior written consent of the representatives of the underwriters.

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We will sell to the representatives on completion of the offering, for a total purchase price of $145, representatives options entitling the representatives or their assigns to purchase 145,000 units consisting of options to purchase 145,000 shares of common stock and options to purchase 145,000 warrants. The warrants will entitle them to purchase an additional 145,000 shares of common stock. The representatives options will be exercisable commencing 180 days from the date of this prospectus and will expire five years from the date of this prospectus. The representatives options will contain certain anti-dilution provisions and provide for the cashless exercise of the representatives options utilizing our securities. The exercise price of the representatives options to purchase the 145,000 shares of common stock is 150% of the $6.00 public offering price of the common stock or $9.00 per share. The exercise price of the representative s options to purchase the 145,000 warrants is 165% of the $0.10 public offering price of the warrants or $0.165 per warrant. The exercise price of the 145,000 shares of common stock underlying the warrants is 120% of the public offering price of the units or $7.32 per share of common stock.

We will set aside and at all times have available a sufficient number of shares of common stock and warrants to be issued upon exercise of the representatives options and warrants. The representatives options and warrants and underlying securities will be restricted from sale, transfer, assignment or hypothecation for a period of 180 days after the date of this prospectus, except to officers of the representatives, co-underwriters, selling group members and their officers or partners. Thereafter, the representatives options and warrants and underlying securities will be transferable provided such transfer is in accordance with the provisions of the Securities Act. Subject to certain limitations and exclusions, we have agreed, at the request of the representatives, to register for sale the common stock and warrants issuable upon exercise of the representatives options and the underlying shares of common stock issuable upon exercise of the warrants included in the representatives options.

For a period of three years after the date hereof, the representatives have the right to designate an observer to our board of directors. Such observer will be reimbursed for his or her reasonable expenses for attending meetings of our board of directors and will receive compensation excluding any grants of options, equal to that received by the highest compensated outside director but will have no voting rights.

At the closing of the offering, we will enter into a consulting agreement retaining Neidiger, Tucker, Bruner, Inc. and Lane Capital Markets as financial consultants at an aggregate of $3,000 per month for a 24 month period; provided, however, the total amount under the consulting agreement of $72,000, less $18,000 previously paid by us to the consultants, shall be paid upon execution of the consulting agreement.

While prior to this offering, there has been a public market for our common stock on the American Stock Exchange, the public offering price of the units, and the common stock and warrants comprising the units, offered by this prospectus has been determined by arm s-length negotiation between the representatives and us. There is no direct relation between the offering price of the units and the historical trading price of our common stock on the American Stock Exchange, our assets, book value or net worth. Among the most significant factors considered by us and the representatives in pricing the units, and the underlying common stock and warrants (including the exercise price of the warrants) was the recent trading prices of our common stock on the American Stock Exchange. Other factors that were considered include our results of operations, our current financial condition and our future prospects, the experience of management, the amount of ownership to be retained by present stockholders, the general condition of the economy and the securities markets and the demand for securities of companies considered comparable to us.

In connection with this offering, the underwriters and we have agreed to indemnify each other against certain liabilities, including liabilities under the Securities Act of 1933 and if such indemnification is unavailable or insufficient, we and the underwriters have agreed to damage contribution arrangements based upon relative benefits received from this offering and relative fault resulting in such damage.

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American Stock Exchange Listing

The units have been approved for listing on the American Stock Exchange under the symbol ARD.u , subject to official notice of issuance. Our common stock is currently traded on the American Stock Exchange under the symbol ARD . Until the units are divided into their separate components of one share of common stock and one warrant, the units will trade separately on the American Stock Exchange (concurrently with our presently issued shares of common stock that trade on the American Stock Exchange). Each unit will be divided into its separate component of one share of common stock and one warrant upon the earlier of one year from the date of this prospectus, or upon thirty (30) days prior written notice from us. However, we will not allow separation of the units until the earlier to occur of 60 days immediately following this offering or the exercise by the underwriters of the entire over-allotment option. Following the separation of the units, the shares of common stock will trade on the American Stock Exchange (and will be indistinguishable from our common stock currently trading on such exchange), and the warrants will trade separately from the common stock on such exchange, under the symbol ARD.ws . The units will cease to exist at such time.

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LEGAL MATTERS

The validity of the shares of common stock issued in this offering will be passed upon for us by the law firm of Johnson, Jones, Dornblaser, Coffman & Shorb, P.C. Certain legal matters in connection with this offering will be passed upon for the underwriters by the law firm of Jones & Keller, P.C.

EXPERTS

The balance sheets of Arena Resources, Inc. as of December 31, 2003 and 2002, and the statements of operations, stockholders equity, and cash flows for the years then ended, have been included in this prospectus and elsewhere in the registration statement in reliance on the report of Hansen, Barnett & Maxwell, independent certified public accountants, given on authority of that firm as experts in accounting and auditing.

The statements of oil and gas revenues and direct operating costs of the East Hobbs San Andres Property interests acquired by Arena Resources, Inc. for the years ended December 31, 2003 and 2002 have been included in this prospectus and elsewhere in the registration statement in reliance on the report of Hansen, Barnett & Maxwell, independent certified public accountants, given on authority of that firm as experts in accounting and auditing.

The estimated reserve evaluations and related calculations for reserves of Lee Keeling and Associates, Inc., independent petroleum engineering consultants have been referenced in this prospectus in reliance on the authority of said firm as experts in petroleum engineering.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC under the Securities Act a registration statement on Form SB-2 in connection with this offering. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other document are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit.

For further information pertaining to us and the units offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330.

In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed through the SEC s EDGAR System, including our registration statement and the exhibits filed with the registration statement. The web site can be accessed at *http://www.sec.gov*.

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ARENA RESOURCES, INC.

INDEX TO FINANCIAL STATEMENTS

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ARENA RESOURCES, INC.

CONDENSED BALANCE SHEETS

(UNAUDITED)

	Pro Forma March 31, 2004 - Note 1	March 31, 2004 (As Restated - Note 1)
ASSETS		
Current Assets		
Cash	$ 1,238,282	$ 1,238,282
Accounts receivable	611,736	424,515
Short-term investments	25,234	25,234
Prepaid expenses	32,526	32,526
Total Current Assets	1,907,778	1,720,557
Property and Equipment, Using Full Cost Accounting		
Oil and gas properties subject to amortization	18,849,527	8,866,225
Drilling advances	244,795	244,795
Equipment	48,480	48,480
Office equipment	36,424	36,424
Total Property and Equipment	19,179,226	9,195,924
Less: Accumulated depreciation and amortization	(670,349)	(670,349)
Net Property and Equipment	18,508,877	8,525,575
Deferred Offering Costs	245,660	245,660
Total Assets	$ 20,662,315	$ 10,491,792
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts payable	$ 296,002	$ 194,366
Accrued liabilities	71,413	43,413
Put option	2,905	2,905
Short-term note payable	2,000,000	
Total Current Liabilities	2,370,320	240,684
Long-Term Liabilities		
Notes payable	8,008,440	
Notes payable to related parties	400,000	400,000
Asset retirement liability	651,943	619,496
Deferred income taxes	841,791	841,791

Total Long-Term Liabilities	9,902,174	1,861,287
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; 7,167,097 shares outstanding	7,167	7,167
Additional paid-in capital	7,019,494	7,019,494
Options and warrants outstanding	810,340	810,340
Retained earnings	552,820	552,820
Total Stockholders Equity	8,389,821	8,389,821
Total Liabilities and Stockholders Equity	$ 20,662,315	$ 10,491,792

See the accompanying notes to unaudited condensed financial statements.

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ARENA RESOURCES, INC.

CONDENSED STATEMENTS OF OPERATIONS

(UNAUDITED)

For the Three Months Ended March 31,	2004	2003
	(As Restated - Note 1)	
Oil and Gas Revenues	$ 1,200,400	$ 807,021
Costs and Operating Expenses		
Oil and gas production costs	316,290	242,071
Oil and gas production taxes	78,707	53,950
Depreciation, depletion and amortization	111,120	59,747
General and administrative expense	178,202	143,631
Total Costs and Operating Expenses	684,319	499,399
Other Income (Expense)		
Gain from change in fair value of put options		4,775
Accretion expense	(12,295)	(4,782)
Interest expense	(9,113)	(9,863)
Net Other Expense	(21,408)	(9,870)
Income Before Provision for Income Taxes and Cumulative Effect of Change in Accounting Principle	494,673	297,752
Provision for Deferred Income Taxes	185,032	111,433
Income Before Cumulative Effect of Change in Accounting Principle	309,641	186,319
Cumulative Effect of Change in Accounting Principle		(11,813)
Net Income	$ 309,641	$ 174,506
Basic Income Per Common Share		
Before cumulative effect of change in accounting principle	$ 0.04	$ 0.03
Net Income	0.04	0.03
Diluted Income Per Common Share		
Before cumulative effect of change in accounting principle	$ 0.04	$ 0.03
Net Income	0.04	0.03

See the accompanying notes to unaudited condensed financial statements.

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ARENA RESOURCES, INC.

CONDENSED STATEMENTS OF CASH FLOWS

(UNAUDITED)

For the Three Months Ended March 31,	2004	2003
	(As Restated - Note 1)	
Cash Flows From Operating Activities		
Net income	$ 309,641	$ 174,506
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	111,120	59,747
Gain from change in fair value of put option		(4,776)
Cumulative effect of change in accounting principle		11,813
Accretion of discounted liabilities	12,295	4,782
Changes in assets and liabilities:		
Accounts receivable	(35,605)	(5,454)
Prepaid expenses	(3,591)	(1,000)
Accounts payable and accrued liabilities	(10,182)	(72,784)
Deferred income taxes	185,032	111,431
Net Cash Provided by Operating Activities	568,710	278,265
Cash Flows from Investing Activities		
Purchase of oil and gas properties	(296,620)	(153,715)
Purchase of office equipment	(17,446)	
Net Cash Used in Investing Activities	(314,066)	(153,715)
Cash Flows From Financing Activities		
Proceeds from issuance of common stock and warrants, net of offering costs	(114,788)	183,739
Proceeds from exercise of warrants	21,750	
Collection of common stock subscription receivable		157,500
Payment of accrued dividends to preferred stockholders		(46,384)
Net Cash Provided by (Used in) Financing Activities	(93,038)	294,855
Net Increase in Cash	161,606	419,405
Cash at Beginning of Period	1,076,676	796,915
Cash at End of Period	$ 1,238,282	$ 1,216,320
Supplemental Cash Flows Information		
Cash paid for interest	$ 9,863	$ 9,866

See the accompanying notes to unaudited condensed financial statements.

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS

MARCH 31, 2004

NOTE 1 BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Condensed Financial Statements The accompanying condensed financial statements have been prepared by the Company and are unaudited. In the opinion of management, the accompanying unaudited financial statements contain all adjustments necessary for fair presentation, consisting of normal recurring adjustments, except as disclosed herein.

The accompanying unaudited interim financial statements have been condensed pursuant to the rules and regulations of the Securities and Exchange Commission; therefore, certain information and disclosures generally included in financial statements have been condensed or omitted. The condensed financial statements should be read in conjunction with the Company s annual financial statements included in its annual report on Form 10-KSB as of December 31, 2003. The financial position and results of operations for the three months ended March 31, 2004 are not necessarily indicative of the results to be expected for the full year ending December 31, 2004.

Nature of Operations The Company owns interests in oil and gas properties located in Oklahoma, Texas, Kansas and New Mexico. The Company is engaged primarily in the acquisition, exploration and development of oil and gas properties and the production and sale of oil and gas.

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

Pro Forma Balance Sheet On May 7, 2004, the Company acquired a working interest in the East Hobbs San Andres Property mineral lease as described more fully in Note 3. In order to facilitate the closing of the acquisition, on May 7, 2004, the Company borrowed $8,008,440 under the terms of a long-term revolving credit facility and borrowed $2,000,000 under the terms of a short-term bridge financing arrangement; the terms of which are both described in Note 4. The accompanying pro forma condensed balance sheet as of March 31, 2004 has been prepared to present the estimated effects of the acquisition and these financing transactions on the financial position of the Company as if they had occurred on March 31, 2004.

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

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves and estimated future costs of abandonment and 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. The Company evaluates oil and gas properties for impairment at least quarterly. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Amortization expense for the three months ended March 31, 2004 was $111,120 based on depletion at the rate of $3.00 per barrel of oil equivalent compared to $59,747 based on depletion at the rate of $2.35 per barrel of oil equivalent for the three months ended March 31, 2003. These amounts include $3,299 and $2,376 of depreciation on equipment during the three months ended March 31, 2004 and 2003, respectively.

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS (Continued)

MARCH 31, 2004

In addition, capitalized costs are subject to a ceiling test which limits such costs to the estimated present value of future net revenues from proved reserves, discounted at a 10-percent interest rate, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties. Consideration received from sales or transfers of oil and gas property is accounted for as a reduction of capitalized costs. Revenue is not recognized in connection with contractual services performed in connection with properties in which the Company holds an ownership interest.

Income Per Common Share Basic income per common share is computed by dividing net income by the weighted-average number of common shares outstanding during the period. Diluted income per share reflects the potential dilution that could occur if all contracts to issue common stock were converted into common stock, except for those that are anti-dilutive.

Concentration of Credit Risk and Major Customer The Company currently has cash in excess of federally insured limits at March 31, 2004. During the three months ended March 31, 2004, sales to three customers represented 47%, 24% and 17% of total sales, respectively. At March 31, 2004, these three customers made up 39%, 29% and 15% of accounts receivable, respectively.

Stock-Based Employee Compensation The Company applies the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations in accounting for its stock-based compensation awards to employees. Under APB 25, no stock-based compensation expense was charged to earnings, as all options granted had an exercise price equal to or greater than the adjusted fair value of the underlying common stock on the grant date.

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

For the Three Months Ended March 31,	**2004**	**2003**
Net income, as reported	$ 309,641	$ 174,506
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(127,099)	
Pro Forma Net Income	$ 182,542	$ 174,506
Income per Common Share		
Basic, as reported	$ 0.04	$ 0.03

Basic, pro forma	0.03	0.03
Diluted, as reported	0.04	0.03
Diluted, pro forma	0.02	0.03

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS (Continued)

MARCH 31, 2004

Restatement The Company revised its estimates of oil and gas reserves and estimated future development costs. The revision of those estimates resulted in an increase in depreciation, depletion and amortization for the three months ended March 31, 2004 and 2003. The accompanying financial statements have been restated as a result of the change in depreciation, depletion and amortization. The effects of the restatement were as follows:

	As Previously Reported	Effect of Restatement	As Restated
For the Three Months Ended March 31, 2004			
Depreciation and amortization	$ 97,555	$ 13,565	$ 111,120
Income before provision for income taxes	508,238	(13,565)	494,673
Provision for deferred income taxes	189,508	(4,476)	185,032
Net income	318,730	(9,089)	309,641
Basic income per common share	0.04		0.04
Diluted income per common share	0.04		0.04
For the Three Months Ended March 31, 2003			
Depreciation and amortization	$ 51,091	$ 8,656	$ 59,747
Income before provision for income taxes and cumulative effect of change in accounting principle	306,408	(8,656)	297,752
Provision for deferred income taxes	114,289	(2,856)	111,433
Income before cumulative effect of change in accounting principle	192,119	(5,800)	186,319
Net income	180,306	(5,800)	174,506
Basic income per common share	0.03		0.03
Diluted income per common share	0.03		0.03
As of March 31, 2004			
Property and equipment, net	$ 8,584,615	$ (59,040)	$ 8,525,575
Total assets	10,550,832	(59,040)	10,491,792
Deferred income taxes	861,273	(19,482)	841,791
Total long-term liabilities	1,880,769	(19,482)	1,861,287
Retained earnings	592,378	(39,558)	552,820
Total stockholders equity	8,429,379	(39,558)	8,389,821

NOTE 2 EARNINGS PER SHARE INFORMATION

For the Three Months Ended March 31,	2004	2003
Income before cumulative effect of change in accounting principle	$ 309,641	$ 186,319
Cumulative effect of change in accounting principle		(11,813)

Net Income	$ 309,641	$ 174,506
Basic Weighted-Average Common Shares Outstanding	7,163,734	6,327,609
Effect of dilutive securities		
Warrants	429,739	133,482
Stock options	258,552	
Diluted Weighted-Average Common Shares Outstanding	7,852,025	6,461,091
Basic Income Per Common Share		
Income before cumulative effect of change in accounting principle	$ 0.04	$ 0.03
Net income	0.04	0.03
Diluted Income Per Common Share		
Income before cumulative effect of change in accounting principle	$ 0.04	$ 0.03
Net Income	0.04	0.03

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS (Continued)

MARCH 31, 2004

NOTE 3 ACQUISITION OF OIL AND GAS PROPERTIES

On May 7, 2004, the Company acquired an 82.24% working interest, 67.60% net revenue interest, in the East Hobbs San Andres Property mineral lease (East Hobbs) located in Lea County, New Mexico. Although the Purchase and Sales Agreement transferred the revenue and the related operating costs from East Hobbs to Arena beginning March 1, 2004, Arena did not control the property interest until May 7, 2004. As a result, the acquisition date for accounting purposes was May 7, 2004 and the operations of East Hobbs operations will be included in the results of operations of Arena from May 7, 2004. Revenues and operating costs for the months of March and April have been estimated and treated as adjustments to the purchase price. Those estimates are subject to adjustment when actual information is available; thus, the purchase price and the allocation of the purchase price are subject to refinement.

East Hobbs is comprised of 20 operating oil and gas wells that were unitized into one lease prior to the acquisition. The Company purchased East Hobbs for its current production and cash flow, as well as for the drilling and secondary recovery opportunities from the property. The purchase price was $10,036,440 and consisted of $10,008,440 of cash and $28,000 of estimated acquisition costs. The acquisition was funded through the use of a credit facility and bridge financing described more fully in Note 4. The purchase price was allocated to the assets acquired and the liabilities assumed as follows:

Accounts receivable	$ 187,221
Oil and gas properties subject to amortization	9,983,302
Total Assets Acquired	10,170,523
Accounts payable	(101,636)
Asset retirement obligation	(32,447)
Total Liabilities Assumed	(134,083)
Net Assets Acquired	$ 10,036,440

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

For the Three Months Ended March 31,	2004	2003
Oil and Gas Revenues	$ 1,813,406	$ 1,481,834
Income from Operations Before Cumulative Effect of Change in Accounting Principle	447,818	373,446
Net Income	447,818	361,633

Basic Income Per Common Share				
Income before cumulative effect of change in accounting principle	$	0.06	$	0.06
Net income		0.06		0.06
Diluted Income Per Common Share				
Income before cumulative effect of change in accounting principle	$	0.06	$	0.06
Net income		0.06		0.06

NOTE 4 NOTES PAYABLE

On February 3, 2003, the Company established a $10,000,000 revolving credit facility with a bank with an initial borrowing base of $2,000,000. On December 31, 2003, the Company entered into an agreement that increased the revolving credit facility to $20,000,000 and increased the initial borrowing base to $4,000,000. On April 14, 2004, the Company changed financial institutions and thereby canceled this credit facility.

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS (Continued)

MARCH 31, 2004

On April 14, 2004, the Company established a new $15,000,000 credit facility from a bank with an $8,500,000 initial borrowing base. Any increases in the borrowing base are subject to written consent by the financial institution. The interest rate is a floating rate equal to the 30, 60 or 90 day LIBOR plus 2.25%, currently 3.42% per annum, and is payable monthly. Annual fees for the facility are 1/8 of one percent of the unused portion of the borrowing base. Amounts borrowed under the revolving credit facility are due in April 2007. The revolving credit facility is secured by the Company s principal mineral interests. In order to obtain the revolving credit facility, loans from two officers were subordinated to the position of the bank. The Company is required under the terms of the credit facility to maintain a tangible net worth of $6,000,000, maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense and maintain a current asset to current liability ratio of 1-to-1, not including the $2,000,000 bridge financing arrangement discussed below. On May 7, 2004, the Company drew $8,008,440 under this revolving credit facility to fund the acquisition of the East Hobbs San Andres Property interests An additional $294,029 is reserved under the revolving credit facility as collateral for standby letters of credit issued to various states.

On April 14, 2004, the Company also entered into to a bridge financing arrangement for $2,000,000 from a bank. On May 7, 2004, the Company borrowed $2,000,000 under the terms of the bridge financing arrangement to fund the acquisition of the East Hobbs San Andres Property interests. The interest rate on the bridge financing arrangement is a floating rate equal to the 30, 60 or 90 day LIBOR plus 2.25%, currently 3.42% per annum, and is payable monthly. The bridge financing arrangement has been guaranteed by two of the Company s officers. Amounts borrowed under the bridge financing arrangement are due June 30, 2004.

On April 13, 2004, the Board of Directors agreed to an extension of the notes payable from two of its officers to July 1, 2005, under the same terms as the original notes.

NOTE 5 ASSET RETIREMENT OBLIGATION

The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The reconciliation of the asset retirement obligation for the three months ended March 31, 2004 is as follows:

Balance, January 1, 2004	$ 607,200
Accretion expense	12,295
Balance, March 31, 2004	$ 619,495

NOTE 6 STOCKHOLDERS EQUITY

Warrants exercised During the three months ended March 31, 2004, the Company issued 5,000 shares of common stock from the exercise of warrants. Of the 5,000 warrants, 1,000 had an exercise price of $1.75 per share and 4,000 had an exercise price of $5.00 per share; therefore, the Company received $21,750 from the exercise.

NOTE 7 CONTINGENCIES AND COMMITMENTS

Standby Letters of Credit A commercial bank has issued standby letters of credit on behalf of the Company to the states of Texas, Oklahoma and New Mexico totaling $294,029 to allow the Company to do business in those states. The standby letters of credit are valid through May 2005 and are collateralized by the revolving credit facility with the bank. The Company intends to renew the standby letters of credit for as long as the Company does business in those states. No amounts have been drawn under the standby letters of credit.

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED CONDENSED FINANCIAL STATEMENTS (Continued)

MARCH 31, 2004

NOTE 8 SUBSEQUENT EVENTS

Subsequent to March 31, 2004, the Company has received $108,750 from exercise of 5,000 warrants that had an exercise price of $1.75 per share and the exercise of 20,000 warrants that had an exercise price of $5.00 per share.

On April 14, 2004, the Company changed financial institutions and established a new revolving credit facility and a bridge financing agreement as of that same date, as further disclosed in Note 4.

On May 7, 2004, the Company closed the acquisition of the East Hobbs San Andres Property interest as further discussed in Note 3.

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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.

As discussed in Note 1, the accompanying financial statements have been restated for the effects of changing estimated depletion, depreciation and amortization.

HANSEN, BARNETT & MAXWELL

Salt Lake City, Utah

January 20, 2004

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ARENA RESOURCES, INC.

BALANCE SHEETS

(As Restated - Note 1)

December 31,	2003	2002
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,076,676	$ 796,915
Accounts 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	559,229	195,608
Net Property and Equipment	8,322,629	4,725,662
Deferred Offering Costs	130,872	
Long-Term Deposits		76,502
Total Assets	$ 9,973,256	$ 6,027,143
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	656,759	179,488

Total Long-Term Liabilities	1,663,959	630,092
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)	243,179	(566,319)
Total Stockholders Equity	8,058,430	5,109,192
Total Liabilities and Stockholders Equity	$ 9,973,256	$ 6,027,143

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

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ARENA RESOURCES, INC.

STATEMENTS OF OPERATIONS

(As Restated - Note 1)

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	360,282	151,197
General and administrative expense	557,576	248,018
Total Costs and Operating Expenses	2,336,557	1,111,242
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	1,305,609	566,537
Provision for Deferred Income Taxes	(484,298)	(179,488)
Income Before Cumulative Effect of Change in Accounting Principle	821,311	387,049
Cumulative Effect of Change in Accounting Principle	(11,813)	
Net Income	809,498	387,049
Preferred Stock Dividends		(798,018)
Income (Loss) Attributable to Common Shares	$ 809,498	$ 410,969
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		
Net Income (Loss) Attributable to Common Shares	$ 0.12	$ (0.09)
Diluted Income (Loss) Per Common Share		
Before cumulative effect of change in accounting principle	$ 0.11	$ (0.09)
Cumulative effect of change in accounting principle		

Net Income (Loss) Attributable to Common Shares	$ 0.11	$ (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

(As Restated - Note 1)

	Preferred Stock		Common Stock		Additional	Options and	Receivable	Retained	Total
					Paid-in	Warrants	from	Earnings	Stockholders
	Shares	Amount	Shares	Amount	Capital	Outstanding	Shareholders	(Deficit)	Equity
Balance, December 31, 2001	857,573	$ 1,274,021	3,604,500	$ 3,605	$ 817,811	$ 103,600	$ (5,733)	$ (155,350)	$ 2,037,954
Issuance for cash	1,028,786	1,214,582			114,402	254,889			1,583,873
Issuance for cash to a related party			70,000	70	88,130				88,200
Issuance for property acquisitions			149,885	150	525,260				525,410
Preferred stock beneficial conversion dividends		114,402						(114,402)	
Preferred stock cash dividends accrued								(274,589)	(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)			130,876
Issuance for cash			286,000	286	493,535	108,315			602,136
Issuance for services			11,000	11	22,539				22,550
Collection of receivable from shareholder							5,733		5,733
Net Income								387,049	387,049
Balance, December 31, 2002			6,282,056	6,282	5,287,189	382,040		(556,319)	5,109,192
Issuance for cash			790,294	790	1,274,256	436,154			1,711,200
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				75,040
Warrant exercise			19,400	19	54,883	(20,952)			33,950
Issuance in property acquisitions			57,000	57	319,493				319,550
Net Income								809,498	809,498

Balance, December 31, 2003		$	7,162,097	$ 7,162	$ 6,994,925	$ 813,164	$		$ 243,179	$ 8,058,430

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

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ARENA RESOURCES, INC.

STATEMENTS OF CASH FLOWS

(As Restated - Note 1)

For the Years Ended December 31,	2003	2002
Cash Flows From Operating Activities		
Net income	$ 809,498	$ 387,049
Adjustments to reconcile net income to net cash provided by operating activities:		
Shares issued for services	75,040	
Depreciation and amortization	360,282	151,197
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	74,787	127,583
Deferred income taxes	484,298	179,488
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

Supplemental Cash Flows Information		
Cash paid for interest	$ 38,798	$ 17,425
Non-Cash Investing and Financing Activities		
Common stock issued for properties less call options granted	$ 319,550	$ 525,410
Asset retirement obligations incurred	559,488	
Accrual of preferred stock dividends		274,589
Receivable from shareholders related to stock offerings		157,500
Preferred stock dividends paid with common stock		409,027
Beneficial conversion feature on convertible preferred stock		114,402
Value of put option included in cost to acquire properties		87,269

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

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS

DECEMBER 31, 2003 AND 2002

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

Cash Equivalents and Short-term investments Cash and cash equivalents include investments in highly-liquid debt instruments with original maturities of three months or less. The Company has deposits with a bank that are $976,676 in excess of federally insured limits at December 31, 2003. Short-term investments consist of certificates of deposit totaling $25,234 which are assigned as collateral under standby letters of credit.

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

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves and estimated future costs of site restoration, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent engineers. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined or until impairment occurs. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Depletion and amortization expense for the year ended December 31, 2003, was $360,282, based on depletion at the rate of $2.79 per barrel-of-oil-equivalent and for the year ended December 31, 2002, was $151,197, based on depletion at the rate of $2.27 per barrel-of-oil-equivalent.

In addition, capitalized costs are subject to a ceiling test, which limits such costs to the aggregate of the estimated present value, discounted at a 10-percent interest rate of future net revenues from proved reserves, based on current economic and operating conditions, plus the lower of cost or fair market value of unproved properties.

Support and Office Equipment Depreciation of support and office equipment is computed using the straight-line method over the estimated useful life of the assets which is currently seven years. Depreciation expense was $9,950 and $3,456 for the years ended December 31, 2003 and 2002, respectively.

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

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

Basic and Diluted Income (Loss) Per Share Basic income (loss) per common share is computed by dividing income (loss) attributable to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted income (loss) per share is calculated to give effect to potentially issuable common shares except during loss periods when those potentially issuable common shares would decrease loss per common share. There were 507,200 warrants outstanding at December 31, 2002 that were excluded from the calculation of diluted loss per common share during the year ended December 31, 2002 because they were anti-dilutive.

Major Customers During the year ended December 31, 2003, sales to three customers represented 51%, 19% and 11% of total sales, respectively. At December 31, 2003, these three customers made up 46%, 16% and 17% of accounts receivable, respectively. During the year ended December 31, 2002, sales to two customers represented 47% and 31% of total sales. At December 31, 2002, these customers made up 56% and 19% of accounts receivable, respectively.

Stock-Based Employee Compensation On April 1, 2003 and on August 12, 2003, the Company issued stock options to directors and employees, which are described more fully in Note 7. The Company applies the recognition and measurement principles of Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations in accounting for its stock-based compensation awards to employees. Under APB 25, no stock-based compensation expense was charged to earnings, as all options granted had an exercise price equal to or greater than the adjusted fair value of the underlying common stock on the grant date.

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

For the Years Ended December 31,	**2003**	**2002**
Net income, as reported	$ 809,498	$ 387,049
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(391,683)	
Pro Forma Net Income	$ 417,815	$ 387,049
Income (Loss) per Common Share		
Basic, as reported	$ 0.12	$ (0.09)
Basic, pro forma	$ 0.06	$ (0.09)
Diluted, as reported	$ 0.11	$ (0.09)
Diluted, pro forma	$ 0.06	$ (0.09)

The pro forma estimated after-tax stock-based compensation expense under SFAS 123 for the years ending December 31, 2004, 2005 and 2006 relating to options outstanding at December 31, 2003, will be approximately $362,000, $214,000 and $126,000, respectively.

Cumulative Effect of Change in Accounting Principle The Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, on January 1, 2003. In accordance with the transition provisions of SFAS No. 143, on that date the Company recorded asset retirement costs and liabilities and recorded an adjustment for

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

the cumulative effect on prior years of adopting SFAS No. 143 in the amount of $11,813 as a reduction in earnings, which had no effect on basic or diluted income per common share.

Recent Accounting Pronouncements In July 2002, the FASB issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal activities*. The statement requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The Company has not been involved in any exit or disposal activities; therefore the adoption of the statement on January 1, 2003 did not have an impact on the Company s financial position or results of operations.

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 of the Company s accounting policy with respect to stock-based employee compensation.

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. The Company does not have an interest in a variable interest entity and the adoption of the statement did not have an impact on the Company s 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 the Company 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. The Company 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 the Company s financial statements.

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

Restatement of Financial Statements The Company revised its estimates of oil and gas reserves and estimated future development costs. The revision of those estimates resulted in an increase in depreciation, depletion and amortization for the years ended December 31, 2003 and 2002. The accompanying financial statements have been restated as a result of the change in depreciation, depletion and amortization. The effects of the restatement were as follows:

	As Previously Reported	Effect of Restatement	As Restated
For the Year Ended December 31, 2003			
Depreciation and amortization	$ 338,157	$ 22,125	$ 360,282
Income before provision for income taxes and cumulative effect of change in accounting principle	1,327,734	(22,125)	1,305,609
Provision for deferred income taxes	491,599	(7,301)	484,298
Income before cumulative effect of change in accounting principle	836,135	(14,824)	821,311
Net income	824,322	(14,824)	809,498
Basic income per common share	0.12		0.12
Diluted income per common share	0.12	(0.01)	0.11
For the Year Ended December 31, 2002			
Depreciation and amortization	$ 127,847	$ 23,350	$ 151,197
Income before provision for income taxes	589,887	(23,350)	566,537
Provision for deferred income taxes	187,193	(7,705)	179,488
Net income	402,694	(15,645)	387,049
Basic loss per common share	(0.09)		(0.09)
Diluted loss per common share	(0.09)		(0.09)
As of December 31, 2003			
Property and equipment, net	$ 8,368,104	$ (45,475)	$ 8,322,629
Total assets	10,018,731	(45,475)	9,973,256
Deferred income taxes	671,765	(15,006)	656,759
Total long-term liabilities	1,678,965	(15,006)	1,663,959
Retained earnings	273,648	(30,469)	243,179
Total stockholders equity	8,088,899	(30,469)	8,058,430
As of December 31, 2002			
Property and equipment, net	$ 4,749,012	$ (23,350)	$ 4,725,662
Total assets	6,050,493	(23,350)	6,027,143
Deferred income taxes	187,193	(7,705)	179,488
Total long-term liabilities	637,797	(7,705)	630,092
Retained earnings	(550,674)	(15,645)	(566,319)
Total stockholders equity	5,124,837	(15,645)	5,109,192

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

NOTE 2 EARNING PER SHARE INFORMATION

For the Years Ended December 31,	2003	2002
Income before cumulative effect of change in accounting principle	$ 821,311	$ 387,049
Less: Preferred stock dividends		(798,018)
Income (loss) before cumulative effect of change in accounting principle	821,311	(410,969)
Cumulative effect of change in accounting principle	(11,813)	
Income (Loss) Attributable to Common Shares	$ 809,498	$ (410,969)
Basic weighted-average common shares outstanding	6,759,858	4,553,232
Effect of dilutive securities		
Warrants	231,476	
Stock options	250,342	
Diluted Weighted-Average Common Shares Outstanding	7,241,676	4,553,232
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		
Net Income (Loss) Attributable to Common Shares	$ 0.12	$ (0.09)
Diluted Income (Loss) Per Common Share		
Before cumulative effect of change in accounting principle	$ 0.11	$ (0.09)
Cumulative effect of change in accounting principle		
Net Income (Loss) Attributable to Common Shares	$ 0.11	$ (0.09)

NOTE 3 ACQUISITION OF OIL AND GAS PROPERTIES

Koehn Property On March 12, 2002, the Company entered into a farm-out agreement relating to certain oil and gas property in Haskell and Gray Counties, Kansas referred to as the Koehn Property. Under the terms of the agreement, the Company agreed to drill one well and could drill additional wells on the property. In exchange for each well drilled, the Company 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, completing and operating the well. After payout, the Company s working interest in the wells and related oil and gas will decrease to 75% (60% of the net revenue interest). The Company successfully drilled one well at a cost of approximately $127,000. The well found proved gas reserves but is currently shut-in pending a pipeline connection.

On March 20, 2002, the Company entered into an agreement with Petro Consultants, Inc. (Petro), a related-party shareholder of the Company, which agreement created a joint venture between the two companies 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, the Company issued 70,000 shares of common stock to Petro to repurchase the 27% working interest in the well. The transactions with Petro have been recognized as a financing arrangement and have been accounted for as the issuance of 70,000 shares of common stock for $88,200 in cash, or $1.26 per share, without other rights to the property.

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

Dodson On April 26, 2002, the Company purchased a working interest in a mineral lease located in Montague County, Texas in exchange for a cash payment of $200,000. In addition, the Company issued 25,000 shares of common stock to Petro as a finder s fee, valued at $2.50 per share, or $62,500, based on the market value of the common stock on the date issued. The finder s fee was capitalized as a cost of the mineral lease.

Ona Morrow On June 18, 2002, the Company purchased a working interest in a mineral lease located in Texas County, Oklahoma for a cash payment of $735,000.

Eva South On July 16, 2002, the Company purchased a working interest in a mineral lease located in Texas County, Oklahoma in exchange for a cash payment of $827,500. In addition, the Company issued 25,000 shares of common stock to Petro as a finder s fee, valued at $4.00 per share, or $100,000, based on the market value of the common stock on the date issued. The finder s fee was capitalized as a cost of the mineral lease.

Midwell, Appleby, Smalts and Hanes On August 23, 2002, the Company entered into an agreement to purchase a working interest in mineral leases located in Cimarron County, Oklahoma. The cost of mineral interests acquired was $550,179 with the consideration given consisting of a cash payment of $100,000, the issuance of 99,885 shares of common stock valued at $399,540 or $4.00 per share based on the market value of the common stock on the date issued, the issuance of a put option to the seller valued at $87,269, less a call option received from the seller valued at $36,630.

Under the terms of the put option, the seller has the right on September 1, 2004, to require the Company to repurchase the 99,885 common shares at $4.00 per share. The issuance of the put option was recorded as a liability based on the holder s ability to require the Company to pay cash to redeem the common stock and was recorded at its fair value of $87,269 on the date issued. The fair value of the put option was computed using the Black-Scholes option pricing model with the following assumptions: 2.2% risk-free interest rate; 43% expected volatility; two years expected life and 0% dividend yield.

The call option received by the Company granted the Company the option to repurchase 50,000 of the common shares at $5.00 per share from the date issued through September 11, 2004. The call option is exercisable at the Company s discretion and was therefore recorded as a reduction of additional paid-in capital based on its fair value of $36,630 on the date received. The fair value of the call option was determined using the Black-Scholes option pricing model with the following assumptions: 2.2% risk-free interest rate; 43% expected volatility; two year expected life and 0% dividend yield. The call option is part of permanent equity and will not be revalued at any future date.

Seven Rivers Queen Unit - On April 4, 2003, the Company entered into an agreement to purchase a 70.60% working interest, representing a 56.48% net revenue interest, in the Seven Rivers Queen Unit mineral lease located in Lea County, New Mexico. Total consideration provided by the Company was a cash payment of $900,000. The Company also issued 10,000 shares of common stock as a finder s fee relating to this acquisition to an unrelated third party, which were valued at $5.20 per share, or $52,000. The value of the shares was based on the market value of the Company s common stock on the date issued.

Beals Prospect - On July 2, 2003, the Company entered into an agreement to purchase a 100% working interest, representing a 80.5% net revenue interest, in the Beals Prospect mineral lease located in Comanche County, Kansas. Total consideration provided by the Company was a cash payment of $60,000 and the issuance of 15,000 shares of common stock as a finder s fee to an unrelated third party, which were valued at $5.80 per share, or $87,000. The value of the shares was based on the market value of the Company s common stock on the date issued. The prospect was unproven, undeveloped acreage. The Company entered into an agreement with Petro Consultants, Inc., a shareholder of the Company, whereby Petro paid the Company $180,000 for a 35%

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

working interest in an explorative well that the Company agreed to drill on the prospect. The cost of the well and the carrying value of the property were reduced by the proceeds received from Petro. When the well was drilled, it was unsuccessful and was plugged and abandoned.

North Benson Queen Unit Effective October 1, 2003, the Company acquired a 100% working interest, representing a 78.15% net revenue interest, in the North Benson Queen Unit in Eddy County New Mexico. Total consideration provided by the Company was a cash payment of $500,000 and the issuance of 25,000 shares of common stock as a finder s fee to an unrelated third party, which were valued at $5.64 per share, or $141,000. The value of the shares was based on the market value of the Company s common stock on the date issued.

West San Andres Unit Effective October 1, 2003, the Company acquired a 100% working interest, representing a 79.60% net revenue interest, in the West San Andres Unit in Yoakum County, Texas. Total consideration provided by the Company was a cash payment of $500,000 and the issuance of 7,000 shares of common stock as a finder s fee to an unrelated third party, which were valued at $5.65 per share, or $39,550. The value of the shares was based on the market value of the Company s common stock on the date issued.

NOTE 4 NOTES PAYABLE AND PUT OPTION

On February 3, 2003, the Company established a $10,000,000 revolving credit facility with a bank with an initial borrowing base of $2,000,000. The interest rate is a floating rate equal to the JP Morgan Chase prime rate plus 1% with interest payable monthly. Annual fees for the facility are $^{1}/2$ of one percent of the unused portion of the borrowing base. Amounts borrowed under the revolving credit facility will be due in February 2005. The revolving credit facility is secured by the Company s principal mineral interests. In order to obtain the revolving credit facility, loans from two officers were subordinated to the position of the bank and the credit facility was guaranteed by two of the Company s officers. The Company is required under the terms of the credit facility to maintain a tangible net worth of $4,000,000, maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense and maintain a current asset to current liability ratio of 1-to-1. The Company is presently current on its undertakings to the bank necessary to maintain this credit facility. As of December 31, 2003, no amounts are owed under this credit facility.

On December 31, 2003, the Company entered into an agreement that increased it s revolving credit facility to $20,000,000 and increased the initial borrowing base to $4,000,000. Additionally, the agreement extended the maturity date to December 31, 2005, annual fees for the facility have been decreased to $^{1}/4$ of 1% of the unused portion of the borrowing base, the Company is now required to maintain a tangible net worth of $6,000,000 and the personal guaranties of the two Company officers are released. All other terms and conditions of the credit facility remain unchanged.

On July 1, 2002, the Board of Directors authorized the Company to borrow up to $500,000 from its officers. On July 26, 2002, the Company borrowed $400,000 from two of its officers. The related notes payable bear interest at 10% per annum payable monthly with principal and interest due December 31, 2002. The notes are secured by all mineral interests, rights and equipment of the Company but have been subordinated to the bank revolving credit facility. On December 30, 2002, the Company and the officers agreed to an 18 month extension to the notes payable, extending the maturity date to June 30, 2004. On August 1, 2003, the Board of Directors and the officers agreed to an additional extension of the notes to January 1, 2005, under the same terms as the original notes. Based on the borrowing rates available to the Company for bank loans, the fair value of the notes payable to officers was $400,000 at both December 31, 2003 and 2002.

The Company granted a put option in connection with the acquisition of oil and gas properties in August 2002. Under the terms of the put option, the seller has the right on September 1, 2004, to require the Company to

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repurchase the 99,885 common shares at $4.00 per share. The put option is a derivative and as such, the liability has been revalued to its fair value at each balance sheet date with adjustments to fair value being recognized as gain on change in fair value of put options. At December 31, 2003 and 2002, the fair value of the liability was $2,905 and $50,604, respectively, calculated using the Black-Scholes option pricing model with the following assumptions: 1.1% and 1.8% risk-free interest rate; 32% and 36% volatility; 0.67 years and 1.7 years expected life; and 0% and 0% dividend yield.

NOTE 5 ASSET RETIREMENT OBLIGATION

Effective January 1, 2003, the Company adopted SFAS No. 143, *Accounting for Asset Retirement Obligations*, which requires entities to record the fair value of a liability for an asset retirement obligation when it is incurred which, for the Company, is typically when an oil or gas well is drilled or purchased. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the asset. The Company s asset retirement obligations relate primarily to the obligation to plug and abandon oil and gas wells and support wells at the conclusion of their useful lives.

SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. When the liability is initially recorded, the related cost is capitalized by increasing the carrying amount of the related oil and gas property. Over time, the liability is accreted upward for the change in its present value each period until the obligation is settled. The initial capitalized cost is amortized as a component of oil and gas properties as described in Note 1.

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

The following present pro forma net income and basic and diluted income (loss) per common share as if SFAS No. 143 had been applied retroactively for the year ended December 31, 2003 and 2002:

For the Years Ended December 31,	**2003**	**2002**
Net Income	$ 809,498	$ 377,396
Income (Loss) Per Common Share		
Basic	$ 0.12	$ 0.08
Diluted	$ 0.11	$ 0.08

The pro forma amount of the liability for the asset retirement obligation was $80,140 at December 31, 2001 and $236,718 at December 31, 2002. The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The reconciliation of the asset retirement obligation for the year ended December 31, 2003 is as follows:

Balance, January 1, 2003	$ 236,718
Liabilities incurred	338,270
Accretion expense	32,212
Balance, December 31, 2003	$ 607,200

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ARENA RESOURCES, INC.

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DECEMBER 31, 2003 AND 2002

NOTE 6 STOCKHOLDERS EQUITY

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

Preferred Stock In June 2001, Arena commenced a Private Placement Offering of 10% convertible preferred shares to accredited investors to raise between $525,000 and $3,500,000 for drilling and completions, as well as additional acquisitions. The offering closed June 30, 2002 with gross proceeds of $3,301,128 and net proceeds of $2,961,495, after cash offering costs totaling $339,633.

During the year ended December 31, 2002, the Company collected $5,733 of subscriptions receivable that were outstanding at December 31, 2001. From January 1, 2002 through July 1, 2002, the Company issued 1,028,786 shares of Class A convertible preferred stock at $1.75 per share under the terms of the private placement offering and realized gross proceeds during that period of $1,800,376 before cash offering costs of $216,503. Offering costs included a 10% cash commission paid to the placement agents on shares they placed. The Company issued the placement agents warrants to purchase 236,786 shares of common stock at $1.75 per share for a period of three years. The Company valued the warrants issued to the placement agents at $254,889 and accounted for the warrants as an additional offering cost. The fair value of the warrants was determined using the Black-Scholes option-pricing model with the following weighted-average assumptions: risk free interest rate of 3.4%, volatility of 47%, expected life of 3 years and expected dividend yield of 0%.

The Company determined that the issuance of Class A preferred stock issued in 2002 resulted in the related shareholders receiving a beneficial conversion option at the dates the preferred stock was issued. This beneficial conversion option was valued at $114,402 based on the difference between the effective conversion price and the market value of the Company s common stock on the dates issued. Since the preferred shares were immediately convertible into common stock, the Company recognized the beneficial conversion option as preferred stock dividends on the dates the preferred stock was issued.

The Class A preferred stock was convertible into common shares from the date of issuance on a 1-for-1 ratio. The Class A preferred shares were automatically convertible into common shares if the price of the common shares was equal to or greater than $4.00 for 20 consecutive days. After one year, the Class A preferred shares were redeemable by the Company, subject to a 30-day notice, at $1.84 per share plus payment of any accrued dividends. The Class A preferred shares accrued dividends at the rate of $0.175 per share annually and were payable quarterly. The Class A preferred shares were non-voting and were entitled to priority over the common shares in the payment of dividends and in liquidation.

On July 30, 2002, the Company s common stock was priced at or above $4.00 per share for the twentieth consecutive day. Accordingly, the 1,886,359 shares of Class A preferred stock were converted into 1,886,359 shares of common stock on July 30, 2002.

The provisions of the preferred stock dictate that dividends will be paid up to the date of conversion or for one year from the date of issuance, whichever is later; accordingly, the Company accrued all remaining cash dividends that were payable in connection with the Series A preferred stock conversion on July 30, 2002. The total Series A preferred stock 2002 dividends payable in cash were $274,589. The Company paid $114,685 in preferred dividends during the year ended December 31, 2003 and $196,048 during the same period of 2002. All accrued dividends have been paid.

On October 1, 2002, the Company offered all former Class A preferred shareholders additional restricted common shares equal to 10% of the common shares issued upon conversion of the preferred stock in exchange

ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

for their agreement and consent not to engage in any sales, assignments or rights related to the common stock issued for a period of twelve months from the earliest date the common stock could otherwise be traded under existing restricted stock agreements or federal securities regulations. Under that offer, the Company issued 181,387 common shares to the former Class A preferred shareholders. In addition, the Company issued the placement agents 18,139 common shares as compensation for obtaining the related lock up agreements. The Company recognized the common shares issued as preferred stock dividends and valued them at $409,027 or $2.05 per share based on the market value of the common stock on the dates the offer was accepted.

Common Stock On August 22, 2002, the Company initiated a $3,000,000 private placement offering of the Company s common stock at $2.50 per share with a detachable warrant exercisable at $5.00 per share through September 30, 2005. Through December 31, 2002, the Company had issued 286,000 shares of common stock and warrants under the terms of the private placement offering for gross proceeds of $715,000 before cash offering costs of $112,864 and were allocated to the common stock issued and the warrants based upon their relative fair value. Accordingly, $493,821 was allocated to the 286,000 shares of common stock, and $108,315 was allocated to the 286,000 warrants. Although the amount allocated to the warrants was less than their fair value, the fair value of the warrants was $278,015 determined using the Black-Scholes option pricing model with the following assumptions: risk free interest rate of 1.8%, expected dividend yield of 0%, volatility of 36.5%, and expected lives of 2.8 years.

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

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

During the years ended December 31, 2003 and 2002, warrant holders exercised 19,400 warrants for $33,950 or $1.75 per share and exercised 74,786 warrants for $130,876 or $1.75 per share, respectively. Additionally, the Company issued 70,847 shares of common stock for services, which the Company valued at an aggregate total of $394,590 or 5.57 per share. The Company capitalized as part of oil and gas properties $319,550 and the remaining $75,040 was charged to expense.

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

Stock purchase warrants issued and exercised during the years ended December 31, 2003 and 2002 are summarized as follows:

	2003		2002	
	Warrants	Weighted-Average Exercise Price	Warrants	Weighted-Average Exercise Price
Outstanding at beginning of year	507,200	$ 3.58	59,200	$ 1.75
Issued	947,923	4.89	522,786	3.53
Exercised	(19,400)	1.75	(74,786)	1.75
Outstanding at End of Year	1,435,723	$ 4.47	507,200	$ 3.58

Stock purchase warrants outstanding at December 31, 2003 are as follows:

Warrants Outstanding	Exercise Price	Weighted-Average Remaining Contractual Life
201,800	$ 1.75	1.5 years
50,000	3.00	2.5
1,183,923	5.00	1.7
1,435,723		

Call Option The Company received a call option in August 2002 in connection with the purchase of oil and gas properties. The option permits the Company to repurchase 50,000 shares of its common stock at $5.00 per share through September 11, 2004. The call option is exercisable at the Company s discretion and was recorded as a reduction of additional paid-in capital based on its fair value of $36,630 on the date received. The fair value of the call option was determined using the Black-Scholes option pricing model with the following assumptions: 2.2% risk-free interest rate; 43% expected volatility; two year expected life and 0% dividend yield. The call option is part of permanent equity and will not be revalued.

NOTE 7 EMPLOYEE STOCK OPTIONS

On April 1, 2003 and on August 12, 2003, the Company granted nonqualified stock options to directors and employees to purchase 1,000,000 shares and 50,000 shares of common stock at $3.70 per share and $4.80 per share through April 1, 2008 and August 12, 2008, respectively. Effective July 31, 2003, 50,000 of the options with an exercise price of $3.70 per share were forfeited. The options vest at the rate of 20% each year over five years beginning one year from the date granted. The exercise price was 85% of the market value of the Company s common stock on the dates issued. In accordance with FASB Interpretation No. 44, *Accounting for Certain Transactions Involving Stock Compensation*, the 15% discount from the market price of the Company s common stock used in determining the fair value of the common stock is considered reasonable and the options are not compensatory. Accordingly, the Company did not recognize any compensation expense from the grant of these stock options. A summary of the status of the stock options as of December 31, 2003 and changes during the year then ended is as follows:

	Options	**Weighted-Average Exercise Price**
Granted	1,050,000	$ 3.75
Forfeited	(50,000)	3.70
Outstanding at End of Year	1,000,000	$ 3.76
Options exercisable at end of year		

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

The fair value of the options granted, net of forfeitures, was $1,862,864, or $1.86 per share, and was estimated on the dates granted using the Black-Scholes option-pricing model with the following weighted-average assumptions: dividend yield of 0% percent, 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 stock options at December 31, 2003 was 4.2 years.

NOTE 8 RELATED PARTY TRANSACTIONS

In July 2002, the Company borrowed $400,000 from two of its officers under the terms of secured, 10% promissory notes, as more fully described in Note 4.

In 2002, the Company issued common stock to Petro Consultants, Inc. for cash and as compensation for finding and arranging for the purchase of oil and gas properties, as described in Note 3. Petro Consultants, Inc. was a related party shareholder of the Company due to an officer of Petro Consultants, Inc. serving as a director and a consultant to the Company from July 1, 2002 to July 2003. Due to the resignation from that position and relationship, Petro Consultants, Inc. is no longer considered a related party. In August 2003, the Company sold an interest in an explorative well to Petro Consultants, Inc for $180,000 as described in Note 3.

NOTE 9 COMMITMENTS

Operating Leases Effective January 1, 2004, the Company entered into a two-year extension to an existing operating lease agreement for office space. Under terms of the lease, the Company pays $1,700 per month through December 31, 2005. The Company incurred lease expense of $10,640 for the year ended December 31, 2003. The future minimum lease payments under the operating lease agreement as of December 31, 2003 consist of $20,400 due during the year ending December 31, 2004 and $20,400 due during the year ending December 31, 2005.

Standby Letters of Credit A commercial bank has issued standby letters of credit on behalf of the Company to the states of Texas, Oklahoma and New Mexico totaling $256,529 to allow the Company to do business in those states. The standby letters of credit are collateralized by an assignment of certificates of deposit totaling $25,000 and by the credit facility with a bank. The Company intends to renew the standby letters of credit for as long as the Company does business in those states. No amounts have been drawn under the standby letters of credit.

NOTE 10 INCOME TAXES

The provision for income taxes consisted of the following:

For the Years Ended December 31,	2003	2002
Current before benefit of operating loss carry forwards	$ 83,686	$
Current benefit of operating loss carry forwards	(83,686)	
Deferred	484,298	179,488
Provision for Income Taxes	$ 484,298	$ 179,488

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ARENA RESOURCES, INC.

NOTES TO FINANCIAL STATEMENTS (Continued)

DECEMBER 31, 2003 AND 2002

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

For the Years Ended December 31,	**2003**	**2002**
Tax at federal statutory rate (34%)	$ 443,907	$ 192,623
Income not subject to tax	(17,364)	(22,168)
State tax, net of federal benefit	57,255	19,700
Benefit of operating loss carry forwards		(10,667)
Provision for Income Taxes	$ 484,298	$ 179,488

As of December 31, 2003, the Company had net operating loss carry forwards for federal income tax reporting purposes of $39,471 which, if unused, will expire in 2022. The net deferred tax liability consisted of the following:

December 31,	**2003**	**2002**
Deferred tax liabilities		
Depreciation and amortization	$ 41,152	$ (7,705)
Intangible drilling costs	648,126	264,851
Asset retirement costs	208,690	
Total deferred tax liabilities	897,968	257,146
Deferred tax assets		
Asset retirement liability	226,486	
Operating loss carry forwards	14,723	77,658
Total deferred tax assets	241,209	77,658
Net Deferred Income Taxes	$ 656,759	$ 179,488

NOTE 11 SUBSEQUENT EVENTS

Subsequent to December 31, 2003, the Company has drilled and completed the Rexford #1-30 well in Haskell County, Kansas, on the acreage covered by the farm-out agreement entered into on March 12, 2002 as part of the Koehn lease. The well was successful, but has not yet been connected. It is anticipated to be connected later this year.

Subsequent to December 31, 2003, warrants to acquire 5,000 shares of common stock, have been exercised (unaudited).

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ARENA RESOURCES, INC.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES

(Unaudited)

Capitalized Costs Relating to Oil and Gas Producing Activities

December 31,	2003	2002
Unproved oil and gas properties	$ 128,694	$
Proved oil and gas properties	8,334,706	4,884,804
Drilling advances on uncompleted projects	351,000	
Support and office equipment	67,458	36,466
Total capitalized costs	8,881,858	4,921,270
Less accumulated depreciation and amortization	(559,229)	(195,608)
Net Capitalized Costs	$ 8,322,629	$ 4,725,662

Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31,	2003	2002
Acquisition of proved properties	$ 2,470,821	$ 2,659,832
Acquisition of unproved properties	147,000	
Exploration costs	326,410	
Development costs	849,864	579,153
Acquisition of support and office equipment		29,388
Asset retirement costs recognized upon adoption of SFAS No. 143	221,218	
Total Costs Incurred	$ 4,015,313	$ 3,268,373

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

For the Years Ended December 31,	2003	2002

Oil and gas revenues	$ 3,665,477	$ 1,657,037
Production costs	(1,149,136)	(594,863)
Production taxes	(269,563)	(117,164)
Depreciation and amortization	(360,282)	(151,197)
General and administrative expense	(557,576)	(248,018)
Results before income taxes	1,328,920	545,795
Provision for income taxes	(484,298)	(179,488)
Results of Oil and Gas Producing Operations	$ 844,622	$ 366,307

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

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

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ARENA RESOURCES, INC.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (Continued)

(Unaudited)

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

	2003		**2002**	
For the Years Ended December 31,	**Oil [1]**	**Gas [1]**	**Oil [1]**	**Gas [1]**
Proved Developed and Undeveloped Reserves				
Beginning of year	4,113,936	3,187,757	494,823	2,960,373
Purchases of minerals in place	3,175,357	570,924	3,597,156	1,676,706
Improved recovery	18,066	229,626		
Production	(117,646)	(67,329)	(58,717)	(46,819)
Revision of previous estimates	(139,546)	(512,224)	80,674	(1,402,503)
End of Year	7,050,167	3,408,754	4,113,936	3,187,757
Proved Developed Reserves at End of Year	1,580,531	1,612,738	750,464	1,151,985

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

Standardized Measure of Discounted Future Net Cash Flows

December 31,	**2003**	**2002**
Future cash inflows	$ 218,026,254	$ 109,145,883
Future production costs	(64,157,199)	(28,850,909)
Future development costs	(13,609,384)	(6,218,000)
Future income taxes	(45,778,941)	(23,701,042)
Future net cash flows	94,480,730	50,375,932
10% annual discount for estimated timing of cash flows	(49,474,633)	(22,378,108)
Standardized Measure of Discounted Future Net Cash Flows	$ 45,006,097	$ 27,997,824

Changes in the Standardized Measure of Discounted Future Net Cash Flows

For the Years Ended December 31,	2003	2002
Beginning of the year	$ 27,997,824	$ 5,203,372
Purchase of minerals in place	21,333,720	34,477,311
Extensions, discoveries and improved recovery, less related costs	691,469	
Development costs incurred during the year	320,102	215,433
Sales of oil and gas produced, net of production costs	(2,302,405)	(1,057,366)
Accretion of discount	3,012,793	3,525,683
Net changes in prices and production costs	8,222,075	6,456,827
Net change in estimated future development costs	39,219	(142,491)
Revision of previous quantity estimates	(53,908)	(2,497,666)
Revision in estimated timing of cash flows	(5,468,732)	
Net change in income taxes	(8,786,869)	(18,183,279)
End of the Year	$ 45,006,097	$ 27,997,824

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ARENA RESOURCES, INC.

EAST HOBBS SAN ANDRES PROPERTY INTERESTS ACQUIRED

UNAUDITED PRO FORMA FINANCIAL INFORMATION

On May 7, 2004, the Company consummated a transaction pursuant to which it acquired an 82.24% working interest, 67.60% net revenue interest, in the East Hobbs San Andres Property mineral lease (East Hobbs) located in Lea County, New Mexico. The East Hobbs lease was acquired from Enerquest Oil and Gas, Ltd., an unaffiliated company. Although the Purchase and Sales Agreement transferred the revenue and the related operating costs from East Hobbs to Arena beginning March 1, 2004, Arena did not control the property interests until May 7, 2004. As a result, the acquisition date for accounting purposes was May 7, 2004 and the operations of East Hobbs operations will be included in the results of operations of Arena from May 7, 2004. Revenues and operating costs for the months of March and April have been estimated and treated as adjustments to the purchase price. Those estimates are subject to adjustment when actual information is available; thus, the purchase price and the allocation of the purchase price are subject to refinement.

East Hobbs is comprised of 20 operating oil and gas wells that were unitized into one lease prior to the acquisition. The Company purchased East Hobbs for its current production and cash flow, as well as for the drilling and secondary recovery opportunities from the property. The purchase price was $10,036,440 and consisted of $10,008,440 of cash and $28,000 of estimated acquisition cots. The acquisition was funded through the use of a credit facility and bridge financing, secured from MidFirst Bank.

The following unaudited pro forma condensed balance sheet has been prepared as though the acquisition of East Hobbs and the related financing had occurred on March 31, 2004 and the unaudited pro forma condensed statements of operations have been prepared to present the operations of the Company for the three months ended March 31, 2004 and for the year ended December 31, 2003 as though the acquisition of East Hobbs and the related financing had occurred at the beginning of each of those periods. The unaudited pro forma financial information is illustrative of the effects of the acquisition on operations of the Company and does not necessarily reflect the results of operations that would have resulted had the acquisition actually occurred at those dates. In addition, the pro forma financial information is not necessarily indicative of the results that may be expected for the year ending December 31, 2004, or any other period.

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ARENA RESOURCES, INC.

UNAUDITED PRO FORMA CONDENSED BALANCE SHEET

MARCH 31, 2004

	Arena Historical	East Hobbs Property	Pro Forma
ASSETS			
Current Assets			
Cash	$ 1,238,282		$ 1,238,282
Accounts receivable	424,515	187,221(1)	611,736
Short-term investments	25,234		25,234
Prepaid expenses	32,526		32,526
Total Current Assets	1,720,557	187,221	1,907,778
Property and Equipment, Using Full Cost Accounting			
Oil and gas properties subject to amortization	8,866,225	9,983,302(1)	18,849,527
Drilling advances	244,795		244,795
Equipment	48,480		48,480
Office equipment	36,424		36,424
Total Property and Equipment	9,195,924	9,983,302	19,179,226
Less: Accumulated depreciation and amortization	(670,349)		(670,349)
Net Property and Equipment	8,525,575	9,983,302	18,508,877
Deferred Offering Costs	245,660		245,660
Total Assets	$ 10,491,792	$ 10,170,523	$ 20,662,315
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current Liabilities			
Accounts payable	$ 194,366	$ 101,636(1)	$ 296,002
Accrued liabilities	43,413	28,000(1)	71,413
Put option	2,905		2,905
Short-term note payable		2,000,000(1)	2,000,000
Total Current Liabilities	240,684	2,129,636	2,370,320
Long-Term Liabilities			
Notes payable		8,008,440(1)	8,008,440
Notes payable to related parties	400,000		400,000
Asset retirement liability	619,496	32,447(1)	651,943
Deferred income taxes	841,791		841,791
Total Long-Term Liabilities	1,861,287	8,040,887	9,902,174
Stockholders' Equity			
Common stock	7,167		7,167

Additional paid-in capital	7,019,494		7,019,494
Options and warrants outstanding	810,340		810,340
Retained earnings	552,820		552,820
Total Stockholders' Equity	8,389,821		8,389,821
Total Liabilities and Stockholders' Equity	$ 10,491,792	$ 10,170,523	$ 20,662,315

See the accompanying notes to unaudited pro forma condensed financial information.

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ARENA RESOURCES, INC.

UNAUDITED PRO FORMA CONDENSED STATEMENT OF OPERATIONS

FOR THE THREE MONTHS ENDED MARCH 31, 2004

	Arena Historical	East Hobbs Property	Pro Forma
Oil and Gas Revenues	$ 1,200,400	$ 613,006(2)	$ 1,813,406
Costs and Operating Expenses			
Oil and gas production costs	316,290	129,533(2)	445,823
Oil and gas production taxes	78,707	57,035(2)	135,742
Depreciation, depletion and amortization	111,120	83,584(3)	194,704
General and administrative expense	178,202		178,202
Total Costs and Operating Expenses	684,319	270,152	954,471
Other Income (Expense)			
Accretion expense	(12,295)	(772)(4)	(13,067)
Interest expense	(9,113)	(86,562)(5)	(95,675)
Net Other Expense	(21,408)	(87,334)	(108,742)
Income Before Provision for Income Taxes	494,673	255,520	750,193
Provision for Deferred Income Taxes	185,032	117,343(6)	302,375
Net Income	$ 309,641	$ 138,177	$ 447,818
Basic Income Per Common Share	$ 0.04		$ 0.06
Diluted Income Per Common Share	$ 0.04		$ 0.06
Basic Weighted-Average Common Shares Outstanding	7,163,734		7,163,734
Effect of dilutive securities:			
Warrants	429,739		429,739
Stock options	243,441		243,441
Diluted Weighted-Average Common Shares Outstanding	7,836,914		7,836,914

See the accompanying notes to unaudited pro forma condensed financial information.

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ARENA RESOURCES, INC.

UNAUDITED PRO FORMA CONDENSED STATEMENT OF OPERATIONS

FOR THE YEAR ENDED DECEMBER 31, 2003

	Arena Historical	East Hobbs Property	Pro Forma
Oil and Gas Revenues	$ 3,665,477	$ 2,289,659(2)	$ 5,955,136
Costs and Operating Expenses			
Oil and gas production costs	1,149,136	588,692(2)	1,737,828
Oil and gas production taxes	269,563	195,473(2)	465,036
Depreciation, depletion and amortization	360,282	395,351(3)	755,633
General and administrative expense	557,576		557,576
Total Costs and Operating Expenses	2,336,557	1,179,516	3,516,073
Other Income (Expense)			
Gain from change in fair value of put options	47,699		47,699
Accretion expense	(32,212)	(2,852)(4)	(35,064)
Interest expense	(38,798)	(354,813)(5)	(393,611)
Net Other Expense	(23,311)	(357,665)	(380,976)
Income from Operations Before Provision for Income Taxes and Cumulative Effect of Change in Accounting Principle	1,305,609	752,478	2,058,087
Provision for Deferred Income Taxes	(484,298)	(251,404)(6)	(735,702)
Income from Operations Before Cumulative Effect of Change in Accounting Principle	$ 821,311	$ 501,075	$ 1,322,386
Income from Operations Before Cumulative Effect of Change in Accounting Principle per Share			
Basic	$ 0.12		$ 0.20
Diluted	$ 0.11		$ 0.18
Basic Weighted-Average Common Shares Outstanding	6,759,858		6,759,858
Effect of dilutive securities:			
Warrants	231,476		231,476
Stock options	250,342		250,342
Diluted Weighted-Average Common Shares Outstanding	7,241,676		7,241,676

See the accompanying notes to unaudited pro forma condensed financial information.

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ARENA RESOURCES, INC.

NOTES TO UNAUDITED PRO FORMA CONDENSED FINANCIAL INFORMATION

(1) To record the acquisition of the East Hobbs, consisting of recognition of the accounts receivable, accounts payable, asset retirement obligation, properties subject to amortization and the notes payable as discussed in item 5 below.

(2) To record the operating revenues and oil and natural gas production expenses from East Hobbs.

(3) To record amortization of oil and gas properties based on the oil and gas production occurring during the period.

(4) To record accretion of the asset retirement obligation.

(5) To record interest on Arena s revolving credit facility and bridge financing arrangement, both used to acquire East Hobbs. On April 14, 2004, the Company established a $15,000,000 revolving credit facility from MidFirst Bank with an $8,500,000 initial borrowing base. On May 7, 2004, the Company borrowed $8,008,440 under the terms of the revolving credit facility to fund the acquisition of East Hobbs. The interest rate on the revolving credit facility is a floating rate equal to the 30, 60 or 90 day LIBOR rate plus 2.25%, currently 3.42% per annum, and is payable monthly. Amounts borrowed under the revolving credit facility are due April 2007. The revolving credit facility is secured by the Company s principal mineral interests.

On April 14, 2004, Arena entered into to a bridge financing arrangement for $2,000,000 from MidFirst Bank. On May 7, 2004, the Company borrowed $2,000,000 under the terms of the bridge financing arrangement to fund the acquisition of East Hobbs. The interest rate on the bridge financing arrangement is a floating rate equal to the 30, 60 or 90 day LIBOR rate plus 2.25%, currently 3.42% per annum, and is payable monthly. The bridge financing has been guaranteed by two of the Company s officers. Amounts borrowed under the bridge financing arrangement are due June 30, 2004.

(6) To record income taxes on the pro forma income from East Hobbs.

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REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

To the Board of Directors

Arena Resources, Inc.

We have audited the accompanying statements of oil and gas revenues and direct operating costs of the East Hobbs San Andres Property interests acquired for the years ended December 31, 2003 and 2002 (the financial statements). The financial statements present only the revenues and direct operating costs of the East Hobbs San Andres Property interests acquired by Arena Resources, Inc. on May 7, 2004. The financial statements are the responsibility of Crown Quest Operating LLC s management, the operator of the East Hobbs San Andres Property through May 7, 2004. Our responsibility is to express an opinion on the 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 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 oil and gas revenues and direct operating costs of the East Hobbs San Andres Property interests acquired, in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1, the financial statements are not a complete presentation of the operations of the East Hobbs San Andres Property interests acquired.

HANSEN, BARNETT & MAXWELL

Salt Lake City, Utah

April 23, 2004

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ARENA RESOURCES, INC.

EAST HOBBS SAN ANDRES PROPERTY INTERESTS ACQUIRED

STATEMENTS OF OIL AND GAS REVENUES AND DIRECT OPERATING COSTS

	For the Three Months Ended March 31,	For the Years Ended December 31,	
	2004	2003	2002
	(Unaudited)		
Oil and Gas Revenues	$ 613,006	$ 2,289,659	$ 2,250,821
Direct Operating Costs			
Oil and gas production costs	129,533	588,692	573,055
Oil and gas production taxes	57,035	195,473	192,213
Total Direct Operating Costs	186,568	784,165	765,268
Direct Operating Profit	$ 426,438	$ 1,505,494	$ 1,485,553

NOTE TO STATEMENTS OF OIL AND GAS REVENUES AND

DIRECT OPERATING COSTS

Basis of Presentation The accompanying financial statements present only the oil and gas revenues and direct operating costs of the East Hobbs San Andres Property interests acquired by Arena Resources, Inc. on May 7, 2004.

Oil and gas revenues are recognized when sold and delivered to third parties. Direct operating costs are recognized when incurred and include lease operating costs and production taxes directly related to the property interests acquired. Direct operating costs exclude costs associated with acquisition, exploration, and development of oil and gas properties, geological and geophysical expenditures and costs of drilling and equipping productive and non-productive wells. Depreciation and amortization of the oil and gas property interests, general and administrative expense, interest and accretion expense, income taxes and other indirect expenses have been excluded from direct operating profit because their historical amounts would not be comparable to those resulting from future operations; accordingly, the accompanying financial statements are not a complete presentation of the operations of the East Hobbs San Andres Property interests acquired.

ARENA RESOURCES, INC.

EAST HOBBS SAN ANDRES PROPERTY INTERESTS ACQUIRED

SUPPLEMENTAL INFORMATION ON OIL AND GAS RESERVES

(UNAUDITED)

The following estimates of proved reserve quantities and related standardized measure of discounted net cash flow relate only to the East Hobbs San Andres Property interests acquired. They are estimates only and do not purport to reflect realizable values or fair market values. Reserve estimates are inherently imprecise and estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the reserves are located in the United States of America.

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

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ARENA RESOURCES, INC.

EAST HOBBS SAN ANDRES PROPERTY INTERESTS ACQUIRED

SUPPLEMENTAL INFORMATION ON OIL AND GAS RESERVES (Continued)

(UNAUDITED)

For the Years Ended December 31,	2003		2002	
	Oil[1]	Gas[1]	Oil[1]	Gas[1]
Proved Developed and Undeveloped Reserves				
Beginning of year	2,809,907	1,739,601	2,893,091	1,847,814
Production	(68,415)	(89,497)	(83,184)	(108,213)
End of Year	2,741,492	1,650,104	2,809,907	1,739,601
Proved Developed Reserves at End of Year	520,141	460,303	588,556	549,800

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

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

December 31,	2003	2002
Future cash inflows	$ 103,475,255	$ 88,550,403
Future production costs	(22,725,550)	(23,147,938)
Future development costs	(4,352,064)	(4,352,064)
Future income taxes	(25,975,198)	(20,757,136)
Future net cash flows	50,422,443	40,293,265
10% annual discount for estimated timing of cash flows	(24,962,683)	(20,729,656)
Standardized Measure of Discounted Future Net Cash Flows	$ 25,459,760	$ 19,563,609

Changes in the Standardized Measure of Discounted Future Net Cash Flows

For the Years Ended December 31,	2003	2002
Beginning of the year	$ 19,563,608	$ 15,136,842
Sales of oil and gas produced, net of production costs	(1,505,494)	(1,485,553)
Accretion of discount	1,929,789	1,477,045
Net changes in prices and production costs	8,509,268	6,715,730
Net change in income taxes	(3,037,411)	(2,280,456)
End of the Year	$ 25,459,760	$ 19,563,608

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GLOSSARY OF OIL AND NATURAL GAS TERMS

We are engaged in the business of exploring for and producing oil and natural gas. Oil and gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and gas industry. The following glossary clarifies certain of these terms you that may be encountered while reading this Form SB-2 Registration Statement:

acquisition costs of properties means the costs incurred to obtain rights to production of oil and gas. These costs include the costs of acquiring oil and gas leases and other interests. These costs include lease costs, finder s fees, brokerage fees, title costs, legal costs, recording costs, options to purchase or lease interests and any other costs associated with the acquisitions of an interest in current or possible production.

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

Boe Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

completion The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

development costs are costs incurred to drill, equip, or obtain access to proved reserves. They include costs of drilling and equipment necessary to get products to the point of sale and may entail on-site processing.

exploration costs are costs incurred, either before or after the acquisition of a property, to identify areas that may have potential reserves, to examine specific areas considered to have potential reserves, to drill test wells, and drill exploratory wells. Exploratory wells are wells drilled in unproven areas. The identification of properties and examination of specific areas will typically include geological and geophysical costs, also referred to as G&G , which include topological studies, geographical and geophysical studies, and costs to obtain access to properties under study. Depreciation of support equipment, and the costs of carrying unproved acreage, delay rentals, ad valorem property taxes, title defense costs, and lease or land record maintenance are also classified as exploratory costs.

farmout involves an entity s assignment of all or a part of its interest in or lease of a property in exchange for consideration such as a royalty.

future net revenue, before income taxes means an estimate of future net revenue from a property, based on the production of the proven reserves of oil and natural gas believed to be recoverable at a specified date, after deducting production and ad valorem taxes, future capital costs and operating expenses, before deducting income taxes. Future net revenue, before income taxes, should not be construed as being the fair market value of the property.

future net revenue, net of income taxes means an estimate of future net revenue from a property, based on the proven reserves of oil and natural gas believed to be recoverable at a specified date, after deducting production and ad valorem taxes, future capital costs and operating expenses, net of income taxes. Future net revenues, net of income taxes, should not be construed as being the fair market value of the property.

gross oil or gas well or gross acre is a well or acre in which we have a working interest.

Mcf One thousand cubic feet of natural gas.

Mcf/d One Mcf per day.

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

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net oil and gas wells or net acres are determined by multiplying gross wells or acres by our percentage interest in such wells or acres.

Net revenue interest is the owner s percentage share of the monthly income realized from the sale of the 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 burden on the well. When land is leased for drilling, the mineral owner is paid a cash consideration and provided a free interest (royalty interest) in all wells drilled on the leased acreage. There also may be additional royalty interests (overriding royalty interests) reserved in assignments or subleases associated with a property. Royalty interests and overriding royalty interests are negotiable, but usually in combination they range on the order of 20% to 25%. These royalty interests are free and clear of all monthly operational expenses. Therefore, on a lease where the mineral owner gets a carried 12.5% royalty interest, and there exists a 12.5% overriding royalty interest, the lease working interest would be 100%, with a net revenue interest of 75% (100% 25%). This means that the working interest owner(s) pay(s) 100% of all monthly operational expenses, but receives 75% of the monthly income, with the remaining 25% of the income going to the mineral owner and holder of the overriding royalty.

oil and gas lease or lease means an agreement between a mineral owner, the lessor, and a lessee which conveys the right to the lessee to explore for and produce oil and gas from the leased lands. Oil and gas leases usually have a primary term during which the lessee must establish production of oil and or gas. If production is established within the primary term, the term of the lease generally continues in effect so long as production occurs on the lease. Leases generally provide for a royalty to be paid to the lessor from the gross proceeds from the sale of production.

plugging and abandonment Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

present value of future net revenue, before income taxes or *pre-tax PV10%* means future net revenue, before income taxes, discounted at an annual rate of 10% to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties.

present value of future net revenue, net of income taxes means future net revenue, net of income taxes discounted at an annual rate of 10% to determine their present value. The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Also known as the Standardized Measure of Discounted Future Net Cash Flows if SEC pricing assumptions are used.

production costs means operating expenses and severance and ad valorem taxes on oil and gas production.

prospect means a location where both geological and economical conditions favor drilling a well.

proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic recovery by production is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can reasonably be judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

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

proved undeveloped oil and gas reserves are those proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves attributable to any acreage do not include production for which an application of fluid injection or other improved recovery technique is required or contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

PDNP Proved developed nonproducing reserves.

PDP Proved developed producing reserves.

PUD Proved undeveloped reserves.

royalty interest is a right to oil, gas, or other minerals that is not burdened by the costs to develop or operate the related property. Seismic option generally means an agreement in which the mineral owner grants the right to acquire seismic data on the subject lands and grants an option to acquire an oil and gas lease on the lands at a predetermined price.

reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Waterflood 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. Potential problems associated with waterflood techniques include inefficient recovery due to variable permeability, or similar conditions affecting fluid transport within the reservoir.

working interest The interest in an oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith. Stated another way, *working interest* is an interest in an oil and gas property that is burdened with the costs of development and operation of the property

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1,450,000 Units

Each Unit Consisting of One Share of Common Stock

and

One Warrant to Acquire One Share of Common Stock

PROSPECTUS

Neidiger, Tucker, Bruner, Inc. **Lane Capital Markets**

vFinance Investments, Inc.

August 10, 2004