# FORM 10−K

## WARREN RESOURCES INC − WRES

**Filed: March 17, 2005 (period: December 31, 2004)**

Annual report which provides a comprehensive overview of the company for the past year

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# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**
# Form 10−K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the Fiscal Year Ended December 31, 2004**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**COMMISSION FILE NUMBER 000−33275**

# Warren Resources, Inc.
*(Exact name of registrant as specified in its charter)*

| | |
|---|---|
| **Maryland**<br>*(State or other jurisdiction of incorporation or organization)* | **11−3024080**<br>*(I.R.S. Employer Identification Number)* |
| **489 Fifth Avenue, New York, NY**<br>*(Address of principal executive offices)* | **10017**<br>*(Zip Code)* |

**Registrant's telephone number, including area code:**
**(212) 697−9660**
**Securities registered pursuant to Section 12(b) of the Act:**
**None**
**Securities registered pursuant to Section 12(g) of the Act:**
**Common Stock, $.0001 par value per share**
*(Title of Class)*

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S−K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10−K or any amendment to this Form 10−K. ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b−2 of the Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by non−affiliates of the registrant, as of June 30, 2004: There was no publicly quoted market value for the registrant's voting common stock on such date. The registrant has no non−voting common stock.

The number of shares outstanding of each of the registrant's classes of common stock as of March 15, 2005 was 34,619,204 shares of common stock, all of one class.

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**DOCUMENTS INCORPORATED BY REFERENCE:**

Certain portions of the registrant's definitive proxy statement to be filed with the Securities and Exchange Commission pursuant to Regulation 14A, not later than April 29, 2005 in connection with the registrant's 2005 Annual Meeting of Stockholders, are incorporated herein by reference into Part III of this Annual Report on Form 10−K.

**WARREN RESOURCES, INC.**
**FORM 10−K**
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Warren’s logo is a trademark or service mark of Warren. Other trademarks or service marks appearing herein are the property of their respective holders.

As used in this document, “Warren,” “we”, “us” and “our” refer to Warren Resources, Inc. and its subsidiaries. The term “Warren E&P” refers to our wholly owned subsidiary Warren E&P, Inc. (formerly known as Petroleum Development Corporation).

For abbreviations or definitions of certain terms used in the oil and gas industry and in this annual report, please refer to the section entitled “Glossary of Abbreviations and Terms” beginning on page 23.

## PART I

## CAUTIONARY NOTE REGARDING FORWARD−LOOKING STATEMENTS

The statements contained in this annual report on Form 10−K that are not historical are “forward−looking statements,” as that term is defined in Section 21E of the Exchange Act, that involve a number of risks and uncertainties.

These forward−looking statements include, among others, the following:

- our growth strategies;
- our reserve estimates;
- our ability to successfully and economically explore for and develop oil and gas resources;
- anticipated trends in our business;
- our future results of operations;
- our liquidity and ability to finance our exploration and development activities;
- market conditions in the oil and gas industry;
- our ability to make and integrate acquisitions; and
- the impact of environmental and other governmental regulation.

These statements may be found under “Risk Factors”, “Management’s Discussion and Analysis of Financial Condition and Results of Operation”, “Business and Properties” and other sections of this annual report. Forward−looking statements are typically identified by use of terms such as “may”, “will”, “could”, “should”, “expect”, “plan”, “project”, “intend”, “anticipate”, “believe”, “estimate”, “predict”, “potential”, “pursue”, “target” or “continue”, the negative of such terms or other comparable terminology, although some forward−looking statements may be expressed differently.

The forward−looking statements contained in this annual report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. Management cautions all readers that the forward−looking statements contained in this annual report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward−looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward−looking statements due to a number of factors, including:

- the failure to obtain sufficient capital resources to fund our operations;
- an inability to replace our reserves through exploration and development activities;
- unsuccessful drilling activities;
- a decline in oil or natural gas production or oil or natural gas prices;
- incorrect estimates of required capital expenditures;
- increases in the cost of drilling, completion and gas gathering or other costs of production and operations;
- impact of environmental and other governmental regulation;
- hazardous and risky drilling operations; and
- an inability to meet growth projections.

You should also consider carefully the statements under “Management’s Discussion and Analysis of Financial Conditions and Results of Operation — Risk Factors” and other sections of this annual report, which address additional factors that could cause our actual results to differ from those set forth in the forward−looking statements.

All forward−looking statements speak only as of the date of this annual report. We do not intend to publicly update or revise any forward−looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward−looking statements attributable to us or persons acting on our behalf.

**Items 1 and 2:** ***Business and Properties***

**Overview**

We are a growing independent energy company engaged in the exploration and development of domestic onshore natural gas and oil reserves. We focus our efforts primarily on the exploration and development of CBM properties located in the Rocky Mountain region and on our waterflood oil recovery program in the Wilmington Townlot Unit, or the Wilmington unit, in the Wilmington field within the Los Angeles Basin of California. Our CBM operations are located in two core areas: the Washakie Basin, which comprises approximately the southeast one−third of the Greater Green River Basin in southwestern Wyoming, and the Powder River Basin in northeastern Wyoming. We also own conventional production principally in Texas, New Mexico and North Dakota. As of December 31, 2004, we owned natural gas and oil leasehold interests in approximately 267,234 gross (147,984 net) acres, 94% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains. We have identified approximately 1,164 drilling locations on our acreage, primarily on 80−acre and 160−acre well spacing.

In the Washakie Basin, we have assembled a large, predominantly undeveloped CBM leasehold, which we believe positions us for significant long−term growth. Our operations in the Washakie Basin consist of the Atlantic Rim project located along the Basin’s eastern rim and the Pacific Rim project located along its western rim. As of December 31, 2004, we had 252,884 gross (142,182 net) acres prospective for CBM development in this area, of which 135,925 are net undeveloped acres. This acreage contains approximately 1,049 identified CBM drilling locations. We own a 56% average working interest in this acreage.

Our Atlantic Rim project comprises approximately 217,205 gross (114,177 net) acres. As of December 31, 2004, we had participated in the drilling of 72 CBM wells in this project. These wells included 35 producing wells and 37 wells that are awaiting completion of production facilities, all of which we believe are capable of commercial production. Based on geological and seismic data, we previously drilled 26 geological test wells, 11 of which we believe are capable of commercial production. As of December 31, 2004, the estimated proved reserves for the 35 producing wells and for their 38 proved undeveloped offset locations average 0.9 Bcfe per gross well on 80−acre and 160−acre spacing, based upon the reserve report prepared by Williamson Petroleum Consultants, Inc., an independent petroleum engineering firm. In 2004, we entered into an agreement to jointly construct, own and operate compression facilities and a pipeline in the Atlantic Rim with Anadarko Petroleum Corporation. During 2005, we plan to increase our drilling activity in the Atlantic Rim by participating in the drilling of 40 gross (11.4 net) additional wells in this area.

During the last half of 2003, we established our Pacific Rim project which consists of approximately 35,679 gross (28,005 net) acres prospective for CBM development. As of December 31, 2004, we had drilled 19 CBM wells and acquired four previously drilled wells in this project, on 80 and 160−acre spacing. Nine of these wells commenced pumping in June 2004 and we expect the remaining wells to be pumping early in 2005. During 2005, we also plan to increase our drilling activity in the Pacific Rim by participating in the drilling of 19 gross (9.9 net) additional wells in this area.

Our Wilmington unit comprises approximately 1,440 gross (1,242 net) acres and is located in the Wilmington field within the Los Angeles Basin of California. Our Wilmington unit oil reserves are primarily proved undeveloped, or PUDs. We seek to develop these reserves using directional and horizontal drilling and secondary recovery techniques, such as a waterflood recovery program. Estimated proved reserves as of

December 31, 2004 were 23 MMbbls gross (14 MMbbls net), of which 97% are PUDs principally in the Upper Terminal zone. The Wilmington unit contains three additional oil zones that may be prospective for secondary oil recovery operations. As of December 31, 2004, there were 31 gross (15.0 net) producing wells. In November 2004, we entered into an Purchase and Sale Agreement and a Settlement Agreement and Release with Magness Petroleum. Under the Purchase and Sale Agreement we paid $14.8 million and in return we increased our working interest in the Wilmington unit to approximately 98.5%. As a result of the settlement with and acquisition from Magness Petroleum, our estimated total proved natural gas and oil reserves, as of December 31, 2004, adjusted as if the acquisition had occurred on December 31, 2004, would be approximately 128.9 Bcfe and the PV−10 value of these reserves would be approximately $307 million, an increase of approximately 25.3 Bcfe and approximately $65 million PV−10.

As of December 31, 2004, we had estimated net proved reserves of 103.6 Bcfe, with a PV−10 value of $242.3 million, based on the reserve report prepared by Williamson Petroleum Consultants. These estimated net proved reserves are located on approximately 6% of our net acreage. Based on our preliminary results to date, we believe that a substantial amount of our remaining undeveloped CBM acreage in the Washakie Basin has commercial potential.

We currently have interests in 203 gross (80.3 net) producing wells and are the operator of record for 54% of these wells. Through our joint venture agreements, we actively participate in operating activities for most of the wells for which we are not operator of record. On December 31, 2004, total daily production from these wells was 16.7 MMcfe/d gross (4.6 MMcfe/d net). For 2005, we have a total capital expenditure budget of approximately $37.6 million to participate in the drilling of 100 gross (55.9 net) wells.

From our inception in 1990 through 2003, we functioned principally as the sponsor of privately placed drilling programs and joint ventures. During that period, we sponsored 31 drilling programs that raised an aggregate of approximately $228 million. Under these programs, we contribute drilling locations, pay tangible drilling costs and provide turnkey drilling services, natural gas marketing services and well services to the drilling programs and retain an interest in the wells drilled. The programs utilized these funds to pay for intangible drilling costs on properties for which we had assembled the acreage and designated the drilling prospects. On behalf of the drilling programs, we have participated in the drilling of approximately 510 conventional, horizontal and CBM wells, of which approximately 90% were completed as commercial producing wells. At December 31, 2004, we had deferred income from turnkey drilling contracts of approximately $11.9 million related to the drilling programs, which was paid in advance in return for our obligation to drill the corresponding wells on behalf of our drilling programs. The drilling programs will participate with us on a pro rata basis in our drilling activities until the turnkey contracts have been completed, which we expect to occur by the fourth quarter of 2005. We plan to participate with our drilling programs in 2 net wells within the Wilmington unit during 2005. After we have performed our obligations under the turnkey drilling contracts we intend to participate with greater working interests in the wells we drill in the future in order to accelerate our growth in production and reserves. We anticipate that future drilling activities with third parties will consist of joint ventures and similar arrangements. As of December 31, 2004, we had distributed $64.1 million in cash and $60.2 million in our securities to these programs.

In 2004, we raised approximately $41 million through the private placement of 5,875,000 shares of our common stock, together with warrants to purchase 2,937,500 shares of our common stock primarily to five institutional investors managed by a large Boston−based investment advisor and also to five unrelated institutional investors.

Our registration statement filed on Form S−1 (SEC File No. 333−118535) for our initial public offering became effective on December 16, 2004. Our common stock commenced trading on the Nasdaq National Market on December 17, 2004 under the trading symbol “WRES”. On December 16, 2004, we sold 9,500,000 shares of common stock in the initial public offering for aggregate gross proceeds of $71.25 million. After deducting the underwriters’ commission and offering expenses, we received net proceeds of $65.3 million. On December 22, 2004, the underwriters exercised their over−allotment option for an additional 1,425,000 shares of our common stock for additional gross proceeds of $10.7 million, net proceeds of $9.9 million after deducting the underwriters’ commission and offering expenses.

**Business Strategy**

The principal elements of our business strategy are designed to generate growth in oil and gas reserves, production volumes and cash flows at a positive return on invested capital. We plan to focus on the following:

- *Exploit Existing Properties Through the Drillbit.* We intend to increase our proved reserves by drilling numerous locations identified on our Rocky Mountain CBM properties and on our Wilmington unit. As of December 31, 2004, we have identified a total of 1,164 drilling locations, of which we plan to participate in the drilling of 100 gross wells during 2005.

- *Increase Our Working Interest in Future Wells.* We plan to increase our level of participation in future wells by investing more of our own capital to drilling operations in our high growth areas. We believe this will enable us to accelerate our growth in production, reserves and cash flows.

- *Pursue Selective Acquisitions and Joint Ventures.* We believe we are well positioned, given our asset base and technical expertise, to pursue selected acquisitions and attract industry joint venture partners. We expect to pursue further acquisitions of natural gas and oil properties in areas where we have specific technical knowledge and experience. We also plan to enter into additional joint ventures to increase our CBM acreage and develop our reserves.

- *Reduce Costs Through Economies of Scale and Efficient Operations.* As we continue to increase our production and develop our existing properties, we expect that our unit cost structure will benefit from economies of scale. With respect to our CBM operations, we anticipate reducing unit costs by greater utilization of our existing infrastructure over a larger number of wells. We seek to exert more control over costs and timing in our exploration, development and production activities through our operating activities and relationships with our joint venture partners.

**Competitive Strengths**

As a result of the following strengths, we believe we are well positioned to execute our business strategy:

- *Substantial Rocky Mountain Undeveloped CBM Acreage Position.* We believe that the Rocky Mountain region is one of the few remaining high potential CBM natural gas provinces in North America. We have assembled a substantial undeveloped acreage position in the Rocky Mountains of 241,244 gross (135,925 net) acres containing 1,061 identified drilling locations. In the Rocky Mountains, our estimated total net proved reserves of 13.9 Bcf are located on less than 1% of our net acreage.

- *Technical Expertise.* Since the beginning of our CBM operations in 1996, we have gained considerable expertise in advanced CBM drilling, completion and re−entry techniques. We also have expertise in directional and horizontal drilling relating to our waterflood recovery program in the Wilmington unit.

- *Experienced Management Team.* Our management team has 25 years of experience on average in the oil and gas industry, and our technical professionals have 17 years of experience on average in oil and gas operations. Our personnel have extensive experience in managing large−scale operations in each of our areas of concentration. Most members of our senior management have been with us since the mid−1990s.

- *Incentivized Management Ownership.* The equity ownership of our management team is strongly aligned with that of our stockholders. As of March 15, 2005, our 14 directors and executive officers beneficially owned 6,491,344 shares of our common stock, which includes exercisable options to purchase 2,312,285 shares of our common stock.

**Areas of Exploration and Development Activities**

Our exploration and development activities are focused primarily on CBM projects in the Rocky Mountain region and also on waterflood oil recovery in the Wilmington unit in California. The table below highlights our main areas of activity:

| Area | Gross Acres | Net Acres | Planned Gross Wells in 2005 |
|---|---|---|---|
| Washakie: | | | |
| Atlantic Rim | 217,205 | 114,177 | 40 |
| Pacific Rim | 35,679 | 28,005 | 19 |
| Powder River | 5,110 | 2,570 | 12 |
| Wilmington | 1,440 | 1,242 | 29 |
| Other(1) | 7,800 | 1,990 | — |
| Total | 267,234 | 147,984 | 100 |

(1) Includes conventional oil and gas properties located primarily in New Mexico, Texas and North Dakota.

**Rocky Mountain CBM Projects**

*Washakie Basin*

The Washakie Basin is located in the southeast one−third of the Greater Green River Basin in southwestern Wyoming and represents our largest acreage position. As of December 31, 2004, we had assembled 252,884 gross (142,182 net) acres prospective for CBM development in this area, of which 135,925 are net undeveloped. This area contains approximately 1,049 identified drilling locations primarily on 80−acre and 160−acre well spacing. The report prepared by Williamson Petroleum Consultants as of December 31, 2004 estimates that the gross recoverable proved reserves for the 35 wells drilled and their 38 well offsets in our first two pilot programs in this basin were 67.5 Bcfe on 80−acre and 160−acre spacing. We own a 56% average working interest in this acreage.

Commercial CBM production in the Washakie Basin was initially established in 2002 on the eastern rim of the Washakie Basin both by us and by Double Eagle Petroleum Co., an independent energy company. The Washakie Basin is generally characterized by shallow Mesa Verde coalbeds. The Mesa Verde coalbeds in this area differ from those found in the Powder River Basin in that they are thinner zones but have significantly higher gas content, much like the coalbeds found in the Drunkard’s Wash field in the Uinta Basin of Utah. CBM field development in the Washakie Basin is usually accomplished by grouping wells into “pods” of 10 to 24 wells, complete with associated infrastructure, including water disposal wells, gathering and compression. The productive pods are typically grouped into individual federal units of up to 25,000 acres each, which facilitates development operations.

***Atlantic Rim Project***

Our Atlantic Rim project comprises approximately 217,205 gross (114,177 net) acres on the eastern rim of the Washakie Basin. We have drilled a total of 34 CBM wells in the Atlantic Rim project in 2004, for a total of 98 wells. Additionally, upon completion of an ongoing environmental impact study being conducted on the Atlantic Rim area by the Rawlins Office of the Bureau of Land Management, or BLM, covering approximately 310,000 acres, we plan to significantly increase drilling activities in the Atlantic Rim project. We believe this study should be completed in 2005. We are jointly developing all of our Atlantic Rim projects within the area of mutual interest, or AMI, with Anadarko. Anadarko is the operator of record for the Atlantic Rim project, and under the Anadarko agreements, our personnel and Anadarko’s personnel have equal input in decision−making for most decisions, including budgets and drilling.

*Sun Dog Unit*

Our initial pod, the Sun Dog unit, is a 10−well pilot program drilled on 80−acre spacing. In 2004 we drilled an additional 2 CBM gross (0.3 net) wells and a second water injection well. We expect production to commence from these additional wells in April 2005. The Sun Dog unit commenced production in April 2002 at a gross rate of approximately 200 Mcf/d of gas and 6,000 Bbls/d of water. Since April 2002, production rates from the Sun Dog unit wells have increased steadily to over 3,770 Mcf/d of gas and 13,000 Bbls/d of water. As of December 31, 2004, the wells have continued to exhibit a typical CBM negative decline curve, increasing daily gas production with relative water production rates decreasing as a percentage of gas production. Based on a report from Williamson Petroleum Consultants, as of December 31, 2004, estimated gross ultimate recoverable proved reserves for the 10 producing wells and 10 undrilled offset locations in the Sun Dog unit average 1.1 Bcfe per well. We currently own a working interest of approximately 29.1% in the wells drilled in the initial pod of the Sun Dog unit. Our working interest in the unit will be approximately 39.67% if the existing unit is fully drilled and developed.

*Blue Sky Unit*

Our second producing pod in the Atlantic Rim project, the Blue Sky unit, is a 12−well pilot program drilled on 160−acre spacing. This program commenced production in August 2003 and as of December 31, 2004, was producing 255 Mcf/d of natural gas and approximately 17,000 Bbls/d of water. Based on prior desorption, permeability, pressure build−up and other tests, we believe that as the wells dewater, the Blue Sky unit wells should exhibit daily production rates and a CBM negative decline curve similar to other CBM wells. In the first half of 2004, we drilled a second water injection well in the Blue Sky unit in order to reduce the water pressure on the producing wells to potentially accelerate gas production from these wells. Based on a report from Williamson Petroleum Consultants, as of December 31, 2004, estimated gross ultimate recoverable proved reserves for the 12 producing wells and 13 undrilled offset locations in the Blue Sky unit average 1.0 Bcfe per well. We currently own an approximate 9.9% working interest in the wells drilled in the initial pod of the Blue Sky unit. Our working interest in the unit will be approximately 39.76% if the existing unit is fully drilled and developed.

*Red Rim Unit*

We are currently developing our first pod in the Red Rim unit. This pod consists of 16 wells on 160−acre spacing. We completed eight CBM wells and one water injection well during 2003 and another eight wells during 2004. The installation of a gathering system and facilities for the entire 16 well project is currently in progress and should be completed early on the second quarter of 2005. We currently own a working interest of approximately 12.25% in the wells drilled in the initial pod of the Red Rim unit. Our working interest in the unit will be approximately 45.46% if the existing unit is fully drilled and developed.

*Doty Mountain Unit*

The first pod in the Doty Mountain unit consists of 24 wells on 80−acre spacing. The 24 producing wells plus one water injection well were drilled and completed in 2004. We plan to commence production from these wells during the first quarter of 2005. We currently own an approximate 8.25% working interest in the wells drilled in the initial pod of the Doty Mountain unit. Our working interest in the unit will be approximately 39.62% if the existing unit is fully drilled and developed.

*Jolly Roger Unit*

We are currently developing our first pod in the Jolly Roger unit. This pod consists of 24 planned wells on 160−acre spacing. We drilled eight wells and one water injection well in 2002, and we expect to participate in the drilling of the remaining 16 wells by the end of 2005. We currently own a working interest of approximately 11.8% in the wells drilled in the initial pod of the Jolly Roger unit. Our working interest in the unit will be approximately 42.97% if the existing unit is fully drilled and developed.

*Muddy Mountain Unit*

We are currently planning to develop the Muddy Mountain unit, our sixth pilot program in the Atlantic Rim, by the end of 2005. This program consists of 24 planned wells on 160−acre spacing and two water injection wells. Additionally, we drilled four test wells adjacent to this pod in 2000, which we believe are capable of commercial production. To the extent they are successfully drilled and completed, we plan to commence production from these 24 CBM wells by the end of 2005. We currently own a working interest of approximately 42.3% in the wells drilled in the initial pod in the Muddy Mountain unit.

***Pacific Rim Project***

Since 2003, we have been acquiring our Pacific Rim acreage located on the western rim of the Washakie Basin, 60 miles west of our Atlantic Rim project. At December 31, 2004, our Pacific Rim project comprised approximately 35,679 gross (28,005 net) acres. We are the operator of record for the Pacific Rim project, which is not subject to the AMI or joint venture agreements with Anadarko. This property includes four previously drilled CBM test wells from which we obtained technical test data, similar in many respects to the data from our Atlantic Rim wells.

In April 2004, we entered into an agreement to acquire an existing 6 1/2−mile gas pipeline that connects the Pacific Rim project to a 20−inch main gas pipeline. This pipeline connects to the Kern River pipeline, which carries gas to Bakersfield, California.

We plan to significantly increase our drilling activity in the Pacific Rim project by up to 120 CBM wells. We received approval of an environmental assessment submitted by us to the Rock Springs, Wyoming office of the BLM in the third quarter of 2004.

*Pacific Isle Unit*

We are currently developing our first pod in the Pacific Isle unit. This pod consists of fifteen wells, two of which we acquired with the property, seven of which we drilled in late 2003 and six that were drilled in 2004. We also drilled a water injection well on this unit in late 2003. Nine of these wells commenced pumping in June 2004 and we expect the remaining six wells to be pumping in early 2005. We currently own an approximate 20% working interest in the wells drilled in the initial pod of the Pacific Isle unit. Our working interest in the unit will be approximately 80% if the existing unit is fully drilled and developed.

*Rifes Rim Unit*

We are currently developing our first pod in the Rifes Rim unit. This pod consists of five planned wells, one of which we acquired with the property, and four of which were drilled in the fourth quarter of 2004. We currently own a working interest of approximately 17.9% in the wells drilled in the initial pod of the Rifes Rim unit. Our working interest in the unit will be approximately 71.83% if the existing unit is fully drilled and developed.

*Chicken Springs Unit*

We are currently developing our first pod in the Chicken Springs unit. This pod consists of four planned wells, one of which we drilled in the second quarter of 2004. We intend to participate in the drilling of the three remaining wells in 2005. We currently own an approximate 15% working interest in the wells drilled in the initial pod of the Chicken Springs unit. Our working interest in the unit will be approximately 60% if the existing unit is fully drilled and developed.

***Powder River Basin***

At December 31, 2004, we owned and operated interests in 117 gross (58.1 net) producing CBM wells on approximately 5,110 gross (2,570 net) acres in the Powder River Basin near Gillette, Wyoming. At December 31, 2004, these wells were producing approximately 5,859 Mcf/d gross (2,594 Mcf/d net). At December 31, 2004, our total estimated net proved reserves in this portion of the Powder River Basin were

7.4 Bcf gross (3.1 Bcf net). Since 2003, we have deepened and recompleted 21 gross (7.2 net) wells in the LX−Bar field in the Powder River Basin to a lower coal seam. At December 31, 2004, gross production from these formerly non−producing wells was 3,600 Mcf/d gross (1,400 Mcf/d net).

**Wilmington Townlot Unit**

Our Wilmington unit is located in the Wilmington field within the Los Angeles Basin of California. The Wilmington field has produced over 2.5 billion barrels of oil since its discovery in the 1920s. Since that time, the Wilmington unit, a unitized oil field consisting of 1,440 gross (1,242 net) acres, has produced more than 149 million barrels of oil from primary production. All the working interests in the Wilmington unit are subject to the terms and provisions of a unit operating agreement.

Our Wilmington unit oil reserves are primarily proved undeveloped, or PUDs. We seek to develop these reserves using directional and horizontal drilling and secondary recovery techniques, such as a waterflood recovery program. As of December 31, 2004, we had 411 Bbls/d gross (218 Bbls/d net) production, compared to 470 Bbls/d gross (137 Bbls/d net) production as of December 31, 2003. In addition, estimated proved reserves as of December 31, 2004 were 23 MMbbls gross (14 MMbbls net), of which 97% are PUDs. Further, as of December 31, 2004, there were 31 gross (15.0 net) producing wells.

Upon acquisition of our initial 50% interest in the Wilmington unit in 1999, we entered into a joint venture with Magness Petroleum to develop the property through directional drilling, applying secondary recovery techniques, such as waterflood redevelopment. Magness Petroleum was to serve as operator for the joint venture wells, with Warren E&P to supervise, coordinate and control the drilling and completion operations. In September 1999, Magness Petroleum commenced litigation against us claiming that we had breached the joint venture agreement and requesting dissolution of the joint venture. The litigation subsequently became two separate arbitration proceedings with additional claims and counterclaims between the parties. In October 2004, we received a $1.6 million arbitration award against Magness Petroleum in one of the arbitration proceedings, with Magness Petroleum's claim for dissolution of the joint venture and our counterclaims still pending in a separate arbitration.

In November 2004, we and Magness Petroleum entered into (i) a purchase and sale agreement, and (ii) a settlement agreement and release, for the purpose of settling all of our disputes and ending arbitration.

On January 31, 2005, with an effective date of January 1, 2005, we closed under the purchase and sale agreement and acquired the interests of Magness Petroleum and its affiliate, Next Generation Investments, LLC, in the Wilmington unit including but not limited to:

- all of the oil and gas mineral leases, working interests, net revenue interests, royalty interests, overriding royalty interests, mineral interests, carried interests and farmout rights described in the agreement;
- certain surface properties and surface estates;
- all oil, gas and water injection wells;
- all leasehold interest in and to areas formally pooled, unitized, communitized or consolidated and approved by the applicable governmental body;
- interests in, to and under or derived from certain contracts, agreements and instruments related to the interests being purchased;
- all easements, permits and agreements with surface owners, surface use agreements, licenses, rights−of−way and other surface rights relating to the interests being purchased;
- certain equipment, machinery, fixtures and other tangible personal property and improvements located on and used in connection with, the interests being acquired; and
- all oil, gas, condensate and other minerals produced from or attributable to the interests in the leases, lands and wells being acquired from the effective date of January 1, 2005.

As consideration for the purchase of the assets described above we paid a total cash purchase price of $14.8 million in the following manner:

- $1.5 million was deposited with an escrow agent within ten days of the date of the purchase agreement;
- at the closing, we delivered an additional $13.3 million to the escrow agent;
- at the closing, the escrow agent delivered $14.55 million to Magness Petroleum and its affiliate;
- the remaining $250,000 of the purchase price will remain in escrow for a period of 90 days after the closing to secure post−closing obligations;
- after any post−closing adjustments during the 90−day period, the escrow agent will pay the balance of the escrow account to Magness Petroleum; and
- assume certain liabilities and obligations of Magness Petroleum and its affiliate associated with the Wilmington unit including Magness Petroleum’s plugging and abandonment obligations.

Under the settlement agreement and release, all awards findings and/or judgments, including a $1.6 million award in our favor, were vacated and all proceedings were dismissed. The parties also agreed to indemnify each other for claims and liabilities relating to the interests and the transactions contemplated under the agreements.

The net result of this transaction with Magness Petroleum is to increase our interest in future development activity in the Wilmington unit to an approximate 98.5% undivided working interest.

The closing of the Purchase and Sale Agreement occurred on January 31 and February 1, 2005. At the closing, the parties terminated their Joint Venture Agreement dated May 24, 1999, Magness Petroleum resigned as the operator of the Wilmington unit, and Warren E&P, Inc. was elected the new operator. We intend to resume drilling in the Wilmington unit as promptly as practicable.

As a result of the settlement with and acquisition from Magness Petroleum, our estimated total proved natural gas and oil reserves, as of December 31, 2004, adjusted as if the acquisition had occurred on December 31, 2004, would be approximately 128.9 Bcfe and the PV−10 value of these reserves would be approximately $307 million, an increase of approximately 25.3 Bcfe and approximately $65 million PV−10.

**Drilling Programs**

Since 1992, we have sponsored 31 drilling programs that have raised approximately $228 million. We have decreased our sponsorship of drilling programs since 2001, raising approximately $15.9 million in two drilling programs in 2001, $5.4 million in one drilling program in 2002 and $6.4 million in one drilling program in 2003. On behalf of the drilling programs, we have participated in the drilling of approximately 510 conventional, horizontal wells and CBM wells, virtually all of which were operated by us, with approximately 90% of such wells being completed and commercially productive.

Under these programs, we contribute drilling locations and pay all tangible drilling costs, while the other investor partners in the drilling programs pay all intangible drilling costs. Warren E&P, Inc., our wholly owned subsidiary, typically contracts with the drilling programs to conduct drilling services on a turnkey, fixed−price basis. Under such contracts, the drilling programs pay a specific price to Warren E&P, based on the depth of the well, for each well drilled regardless of the actual amount of time, materials and expenses required by Warren E&P to drill the well.

We act as the sole managing general partner of each drilling program, and we typically receive a before−payout working interest of 25% (55% after−payout) and drill the wells on a fixed−cost basis. As of December 31, 2004, none of the active 22 drilling programs managed by us had achieved payout status.

In addition, we have marketing agreements with most of the drilling programs under which we purchase oil and gas produced by affiliated joint ventures and partnerships at current field prices, which we transport and market to third parties. We construct our own gas gathering and transportation lines that connect wells owned by joint ventures and partnerships to the pipelines owned by gas transportation companies. We enter into transportation contracts with these companies and sales contracts for the sale of oil and gas to the third party purchasers.

As of December 31, 2004, investor partners in our drilling programs have received cash distributions ranging from below 10% of original capital contributions for programs formed since 2000; between 13% and 29%, or 52% to 69% after federal tax benefits are included assuming the maximum marginal federal income tax rate, for programs formed between 1997 and 1999; and between 40% and 80%, or 78% to 122% after federal tax benefits are included, assuming the maximum marginal federal income tax rate, for 13 of the 15 programs formed in 1996 or earlier. Cash distributions to investor partners are made monthly. Our drilling programs have distributed approximately $64.1 million to investor partners through December 31, 2004, of which $57.7 million were from cash flow generated from oil and gas revenues from the respective drilling programs' wells and $6.4 million were from sales of wells or well equipment. Between December 2002 and March 2003, 13 drilling programs converted from Delaware limited partnerships to Delaware LLCs and on average 75% of the drilling program members elected to convert their interests to preferred member interests in their respective LLCs. Preferred member interests have the right to a preferential return and other preferential rights senior to our and other standard member interests. As a result of these conversions, we issued an aggregate of 3,341,559 restricted convertible preferred shares to the LLCs as additional capital contributions and received as consideration additional standard membership interests in the LLCs, which increased our pro rata beneficial interests in the oil and gas wells owned by the LLCs. Also during 2003, we issued an aggregate of 1,048,336 restricted convertible preferred shares to two joint ventures as additional capital contributions and received as consideration additional joint venture interests in the joint ventures, which increased our pro rata beneficial interests in the oil and gas wells owned by the joint ventures.

Additionally, during 1996 and 1997, we issued $6.3 million of convertible debentures and common stock to purchase investors' interests in the two remaining drilling programs. To the extent that we have an existing obligation to drill program wells as of December 31, 2004, the drilling programs will continue to participate with us on a pro rata basis in our drilling activities until the wells have been drilled, which we expect to occur by the fourth quarter of 2005.

**Natural Gas and Oil Reserves**

The following table presents our estimated proved natural gas and oil reserves and the PV−10 value of our interests in net reserves in producing properties as of December 31, 2004, 2003 and 2002 based on reserve reports prepared by Williamson Petroleum Consultants. The PV−10 values shown in the table are not intended to represent the current market value of the estimated natural gas and oil reserves we own.

A significant portion of our proved developed reserves has been accumulated through our interests in the drilling programs for which we serve as managing general partner. The estimates of future net cash flows and their present values, based on period end prices, are based upon certain assumptions of the drilling programs in which we own interests will achieve payout status in the future. As of December 31, 2004, none of the active 22 drilling programs managed by us had achieved payout status.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| **Estimated Proved Natural Gas and Oil Reserves:** | | | |
| Net natural gas reserves (MMcf): | | | |
| Proved developed | 8,496 | 7,006 | 4,544 |
| Proved undeveloped | 10,046 | 8,442 | 3,959 |
| Total(1) | 18,542 | 15,448 | 8,503 |
| Net oil reserves (MBbls): | | | |
| Proved developed | 395 | 476 | 404 |
| Proved undeveloped | 13,781 | 14,648 | 11,920 |
| Total(2) | 14,176 | 15,124 | 12,324 |
| **Total Net Proved Natural Gas & Oil Reserves (MMcfe)** | 103,601 | 106,190 | 82,447 |
| **Estimated Present Value of Net Proved Reserves:** | | | |
| PV−10 Value (in thousands) Proved developed | $ 26,901 | $ 20,461 | $ 10,041 |
| Proved undeveloped | 215,392 | 162,524 | 103,913 |
| Total | $ 242,293 | $ 182,985 | $ 113,954 |
| Standardized measure of discounted future net cash flows (in thousands)(3) | $ 192,645 | $ 146,126 | $ 71,418 |
| **Prices Used in Calculating Reserves:** | | | |
| Natural Gas (per Mcf) | $ 5.30 | $ 4.50 | $ 3.36 |
| Oil (per Bbl) | 37.59 | 28.45 | 27.15 |
| **Proved Developed Reserves (MMcfe)** | 10,866 | 9,862 | 6,967 |

(1) Included in 2004, 2003 and 2002 reserves, 357 MMcf, 1,028 MMcf and 577 MMcf is attributable to consolidated subsidiaries in which there is an average minority interest of 23%, 25% and 34%, respectively.

(2) Included in 2004, 2003 and 2002 reserves, 2,142 MBbls, 2,469 MBbls and 1,195 MBbls is attributable to consolidated subsidiaries in which there is an average minority interest of 23%, 25% and 34%, respectively.

(3) Standardized measure of discounted future net cash flows differ from PV−10 value because it includes the effect of future income taxes. Included in 2004, 2003 and 2002 standardized measure of discounted future net cash flows $26,054, $23,017 and $10,462 is attributable to consolidated subsidiaries in which there is an average minority interest of 23%, 25% and 34%, respectively.

There are numerous uncertainties in estimating quantities of proved reserves and in projecting future rates of production and the timing of development expenditures, including many factors beyond our control. The reserve data set forth in this annual report are only estimates. Although we believe these estimates to be reasonable, reserve estimates are imprecise and may be expected to change as additional information becomes available. Estimates of natural gas and oil reserves, of necessity, are projections based on engineering data and there are uncertainties inherent in the interpretation of this data, as well as the projection of future rates of production and the timing of development expenditures. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be exactly measured. Therefore, estimates of the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, classifications of the reserves based on risk of recovery and the estimates are a function of the quality of available data and of engineering and geological interpretation and judgment and the future net cash flows expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. There also can be no assurance that the reserves set forth herein will ultimately be produced or that the proved undeveloped reserves will be developed within the periods anticipated. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. In addition, the estimates of future net revenues from our proved reserves and the present value thereof are based upon certain assumptions about future production levels, prices and costs that may not be correct.

With respect to the estimates prepared by Williamson Petroleum Consultants, PV−10 value should not be construed as representative of the fair market value of our proved natural gas and oil properties since discounted future net cash flows are based upon projected cash flows which do not provide for changes in natural gas and oil prices or for the escalation of expenses and capital costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based. Actual future prices and costs may differ materially from those estimated. You are cautioned not to place undue reliance on the reserve data included in this annual report. Under SEC guidelines, estimates of the PV−10 value of proved reserves must be made using oil and gas sales prices at the date for the valuation, which prices are held constant throughout the life of the properties.

**Productive Wells**

The following table sets forth our gross and net productive wells as of December 31, 2004:

| | Natural Gas Wells | | Oil Wells | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| California | 0.0 | 0.0 | 31.0 | 15.0 | 31.0 | 15.0 |
| New Mexico | 19.0 | 0.6 | 5.0 | 0.2 | 24.0 | 0.8 |
| Texas | 6.0 | 1.5 | 0.0 | 0.0 | 6.0 | 1.5 |
| Wyoming | 136.0 | 59.2 | 3.0 | 3.0 | 139.0 | 62.2 |
| Other | 1.0 | 0.7 | 2.0 | 0.1 | 3.0 | 0.8 |
| Total | 162.0 | 62.0 | 41.0 | 18.3 | 203.0 | 80.3 |

Gross wells represent all wells in which we have an interest. Net wells represent the total of our fractional undivided working interest in those wells.

### Drilling Activity

The following table sets forth our drilling activities for the three years 2004, 2003 and 2002:

| | Years Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2004 | | 2003 | | 2002 | |
| | Gross | Net | Gross | Net | Gross | Net |
| **Exploratory Wells**(1) | | | | | | |
| Productive(2) | 52.0 | 5.1 | 16.0 | 2.8 | 15.0 | 1.9 |
| Nonproductive(3) | 1.0 | 0.1 | — | — | — | — |
| **Development Wells**(1) | | | | | | |
| Productive(2) | 14.0 | 2.1 | 19.0 | 3.3 | 12.0 | 2.3 |
| Nonproductive(3) | 1.0 | 0.3 | 1.0 | 0.1 | — | — |
| **Total** | 68.0 | 7.6 | 36.0 | 6.2 | 27.0 | 4.2 |

(1) An exploratory well is a well drilled either in search of a new, as yet undiscovered oil or gas reservoir or to greatly extend the known limits of a previously discovered reservoir. A development well is a well drilled within the presently proved productive area of an oil or gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

(2) A productive well is an exploratory or development well found to be capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(3) A nonproductive well is an exploratory or development well that is not a producing well.

### Natural Gas and Oil Acreage

The following table sets forth our acreage position as of December 31, 2004:

| | Developed | | Undeveloped | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| California | 388 | 334 | 1,052 | 908 | 1,440 | 1,242 |
| New Mexico | 1,386 | 105 | 3,602 | 398 | 4,988 | 503 |
| Texas | 704 | 176 | — | — | 704 | 176 |
| Wyoming | 16,030 | 8,374 | 241,964 | 136,378 | 257,994 | 144,752 |
| Other | 948 | 418 | 1,160 | 893 | 2,108 | 1,311 |
| Total | 19,456 | 9,407 | 247,778 | 138,577 | 267,234 | 147,984 |

### Production Volumes, Sales Prices and Production Costs

The following table summarizes our net natural gas and oil production volumes, our average sales prices and expenses for the periods indicated. Our volumes are attributable to our direct interests in producing properties and the production we are allocated from our 1999 and subsequent drilling programs where we typically receive 25% of the production from such programs. For these purposes, our net production will be production that is owned by us either directly or indirectly through our drilling programs, after deducting royalty, limited partner and other similar interests. The lease operating expenses shown are related only to our net production.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| **Production:** | | | |
| Natural gas (MMcf) | 817.2 | 785.8 | 54.8 |
| Oil (MBbls) | 68.2 | 87.4 | 4.3 |
| Total equivalents (MMcfe) | 1,226.3 | 1,310.1 | 80.3 |
| **Average Sales Price Per Unit:** | | | |
| Natural gas (per Mcf) | $ 5.03 | $ 3.70 | $ 1.90 |
| Oil (per Bbl) | 34.38 | 25.42 | 20.84 |
| Weighted average (per Mcfe) | 5.26 | 3.92 | 2.40 |
| **Expenses (per Mcfe):** | | | |
| Lease operating expense(1)(2)(3) | $ 3.12 | $ 2.94 | $ 1.50 |

(1) Lease operating expenses for 2002 excludes operating expenses incurred by the drilling programs and paid for by us of approximately $1,200,000.

(2) The lease operating expenses for the Wilmington unit that were utilized for this calculation include direct labor that was improperly charged to us by the prior operator of the Wilmington unit.

(3) Lease operating expenses related to our CBM operations include costs for operating our commercially productive CBM wells, together with the costs for operating our CBM wells that are still in the dewatering phase and are not yet commercially productive.

**Purchasers and Marketing**

We sell our natural gas and oil production and that of our drilling programs to various purchasers in the areas where the oil and natural gas is produced. The natural gas is delivered into natural gas pipelines for transportation and is sold to various purchasers for later re−marketing or end use. Our oil is sold to purchasers who take delivery from storage tanks that are located on our property. We are currently able to sell all of the natural gas and oil produced on our behalf and that of our drilling programs. The majority of all of this natural gas and oil is sold under monthly contracts that allow for periodic adjustments in pricing according to market demands.

In addition, approximately 72% of our natural gas production was subject to a firm commitment contract for transportation space, but not sales, with Williston Basin Interstate relating to its LX−Bar lease for 6,000 Mcf/d, which will terminate in October 2006. We sell our natural gas at market price. Further, we have a firm commitment contract relating to our Piper Federal lease covering requirements for us to deliver 2,500 Mcf/d. The maximum penalty for any deficiency is calculated as the deficient Mcf times 90% (amount below 2,500 Mcf times 90%) times the deficiency rate of $0.42 per Mcf representing gathering, compression and transportation charges. This contract terminates on February 1, 2006. The marketing of natural gas and oil can be affected by factors beyond our control, the effects of which cannot be predicted. For more information about the risks to our business posed by our marketing activities see “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Risk Factors — Risks Related to Our Business — Market conditions or operation impediments may hinder our access to natural gas and oil markets or delay our production”.

For 2004, the largest purchasers for our production and that of our drilling programs primarily included Tenaska Marketing Ventures, Anadarko Energy Services and Lunday−Thagard Company, which accounted for 45%, 16% and 25%, respectively, of the total natural gas and oil sold by us and our drilling programs. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as we believe there are a significant number of readily available purchasers in the market.

**Our Service and Operational Activities**

Our drilling, completion, production, re−entry and land operations are conducted, managed and supervised for us and our drilling programs through Warren E&P, Inc., our wholly owned subsidiary. After a long−term joint venture relationship that began in 1990, we acquired Warren E&P on September 1, 2000. See “Certain Relationships and Related Transactions”. Through Warren E&P, we employ petroleum engineers, drilling supervisors, landmen and field supervisors. Warren E&P also employs geologists on a contract basis. As of December 31, 2004, Warren E&P was the operator of approximately 54% of the wells in which we and our drilling programs had interests.

**Competition**

We compete with a number of other potential purchasers of natural gas and oil leases and producing properties, many of which have greater financial resources than we do. In general, the bidding for natural gas and oil leases has become particularly intense in the Powder River and Washakie Basins with bidders evaluating potential acquisitions with varying product pricing parameters and other criteria that result in widely divergent bid prices. The presence of bidders willing to pay prices higher than are supported by our evaluation criteria could further limit our ability to acquire natural gas and oil leases. In addition, low or uncertain prices for properties can cause potential sellers to withhold or withdraw properties from the market. In this environment, we cannot guarantee that there will be a sufficient number of suitable natural gas and oil leases available for acquisition or that we can sell natural gas and oil leases or obtain financing for, or participants to join in, the development of prospects.

**Regulations**

***General***

Our business is affected by numerous laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Most of our drilling operations require permits or authorizations from federal, state or local agencies, respectively, for both the drilling of the well and the production of the natural gas or oil, as well as the disposal of associated wastes, principally water. Changes in any of these laws and regulations or the denial or vacation of permits could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We believe that our operations comply in all material respects with applicable laws and regulations. We believe that the existence and enforcement of such laws and regulations have no more restrictive an effect on our operations than on other similar companies in the energy industry.

Proposals and proceedings that might affect the oil and gas industry are pending before Congress, the BLM, the Federal Energy Regulatory Commission, or FERC, the Minerals Management Service, or MMS, state legislatures and commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material adverse effect upon our capital expenditures, earnings or competitive position.

***Federal Regulation of Sales and Transportation of Natural Gas***

Historically, the transportation and sale of natural gas and its component parts in interstate commerce has been regulated under several laws enacted by Congress and the regulations passed under these laws by FERC. Our sales of natural gas, including condensate and liquids, are affected by the availability, terms, and cost of transportation. The price and terms of access to pipeline transportation are subject to extensive federal and state regulation. From 1985 to the present, several major regulatory changes have been implemented by Congress and FERC that affect the economics of natural gas production, transportation and sales. In addition, FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances.

The ultimate impact of the complex rules and regulations issued by FERC cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial and final FERC decisions. We cannot predict what further action FERC will take on these matters. Some of FERC's more recent proposals may, however, adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. We do not believe that we will be affected by any action taken materially differently than other natural gas producers, gatherers and marketers with whom we compete.

***Operations on Federal Oil and Gas Leases***

We conduct a sizeable portion of our operations on federal oil and natural gas leases which are administered by the BLM and the MMS. Federal leases contain relatively standard terms and require compliance with detailed BLM and MMS regulations and orders, which are subject to change. Under certain circumstances, the BLM may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could have a material adverse effect on our business, financial condition and results of operations. The MMS issued a final rule that amended its regulations governing the valuation of oil and gas produced from federal leases. This new rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil and gas produced from federal leases. The lawfulness of the new rule has been challenged in federal court. We cannot predict whether this new rule will be upheld in federal court, nor can we predict whether the MMS will take further action on this matter. However, we do not believe that this new rule will affect us any differently than other producers and marketers of oil and gas.

***State Regulation***

Our operations are also subject to regulation at the state and in some cases, county, municipal and local governmental levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells and requiring the disposal of fluids used and produced in connection with operations. Our operations are also subject to various conservation laws and regulations pertaining to the size of drilling and spacing units or proration units and the unitization or pooling of oil and gas properties.

In addition, state conservation laws, which frequently establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the rates of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but, except as noted above, does not generally entail rate regulation. These regulatory burdens may affect profitability, but we are unable to predict the future cost or impact of complying with such regulations.

**Environmental Matters**

***General***

We are subject to extensive federal, state and local environmental laws and regulations relating to water, air, hazardous substances and wastes, and threatened or endangered species that restrict or limit our business activities for purposes of protecting human health and the environment. Compliance with the multitude of regulations issued by federal, state, and local administrative agencies can be burdensome and costly. State environmental regulatory programs are generally very similar to the corresponding federal environmental regulatory programs, and federal environmental regulatory programs are often delegated to the states.

Our oil and gas exploration and production operations are subject to state and/or federal solid waste regulations that govern the storage, treatment and disposal of solid and hazardous wastes. However, much of the solid waste generated by our oil and gas exploration and production activities is exempt from regulation under federal, and many state, regulatory programs. To the extent our operations generate solid waste, such waste is generally subject to state regulations. We have complied with solid waste regulations in the normal course of business.

In addition to solid and hazardous waste, our production operations generate produced water as a waste material. This water can sometimes be disposed of by discharging it to surface waters or lands under discharge permits issued pursuant to the Clean Water Act, or an equivalent state program. We have obtained surface discharge permits from the Wyoming DEQ for our operations in some areas, such as the Powder River Basin. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the Safe Drinking Water Act, or an equivalent state regulatory program. The drilling, completion, and operation of produced water disposal wells are integral to oil and gas operations. We already operate produced water disposal wells, particularly in association with our coalbed methane production operations. We are experienced in these activities and are able to perform these activities in a cost−effective manner.

Air emissions and exhaust from some of our equipment, such as gas−tired generators and gas compressors, are potentially subject to regulations under the Clean Air Act, or equivalent state regulatory programs. To the extent that our air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. We have obtained air permits, where needed, in the normal course of business.

Some of our exploration and production activities occur on federal leases. This is particularly true of our CBM operations. Exploration and production operations on federal leases are generally performed in accordance with a record of decision issued by the BLM after preparation of an environmental assessment or an environmental impact statement. A record of decision typically includes environmental and land use provisions that restrict and limit exploration and production activities on federal leases. Much of our CBM operations are subject to records of decision and we have not experienced any material difficulty in complying with their terms and conditions.

In the event spills or releases of crude oil or produced water occur, we would be subject to spill notification and response regulations under the Clean Water Act, or equivalent state regulatory programs. Depending on the nature and location of our operations, we may also be required to prepare spill prevention, control and countermeasure response plans under the Clean Water Act, or equivalent state regulatory programs. Response costs could be high and may have a material adverse effect on our operations. We may not be fully insured for these costs.

Failure to comply with environmental regulations may result in the imposition of substantial administrative, civil, or criminal penalties, or restrict or prohibit our desired business activities. Environmental laws and regulations impose liability, sometimes strict liability, for environmental cleanup costs and other damages. Other environmental laws and regulations may delay or prohibit exploration and production activities in environmentally sensitive areas or impose additional costs on these activities.

We believe we are in compliance with current applicable environmental laws and regulations. Costs associated with responding to a major spill of crude oil or produced water, or costs associated with remediation of environmental contamination, are the most likely occurrences that could result in a material adverse effect on our business, financial condition and results of operations. There are no pending or threatened claims for any such environmental cleanup costs, and we operate our producing properties in a prudent manner in order to avoid or minimize liability related to any such claims.

In addition, changes in applicable federal, state and local environmental laws and regulations potentially could have a material adverse effect on our business, financial condition and results of operations. In this regard, our CBM drilling and production operations are subject to ongoing BLM oversight, EIS development and recurring BLM approvals, and could be affected by changes in BLM regulations or policies.

We anticipate that total maximum daily load water quality standards established under Clean Water Act delegated programs may be promulgated for surface water bodies in areas where we operate, including the Powder River Basin. However, we do not expect that any total maximum daily load regulations, or standards promulgated in any area where we operate, will result in a material increase in our produced water disposal costs, as we already inject much of our produced water in disposal wells, rather than discharging into surface water bodies, and would be able to cost−effectively drill and operate additional disposal wells as needed.

We anticipate no material estimated capital expenditures to comply with federal and state environmental requirements. In addition, state−wide reclamation bonds and our $50.0 million casualty and environmental insurance have been adequate to meet the applicable Wyoming bonding and insurance requirements to date. Finally, we have posted a $3.0 million U.S. treasury bond, with a fair value of $2,766,000 as of December 31, 2004, as collateral for a $3.4 million reclamation bond for the Wilmington unit.

***Coalbed Methane Operations***

The majority of our gas production is from CBM operations that generate water discharges and air emissions that are subject to significant regulatory control. Naturally occurring groundwater is produced by our CBM production operations. This produced water is disposed of by re−injection into the subsurface through disposal wells, and discharge to the surface or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by state regulatory agencies, and in compliance with applicable, state and local environmental regulations. To date, we have been able to obtain necessary surface discharge or disposal well permits and we have been able to discharge produced water and operate our produced water disposal wells in compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities.

Our CBM operations involve the use of gas−fired generators and compressors to transport gas that we produce. Emissions of nitrogen oxides and other combustion by−products from individual or multiple generators and compressors at one location may be great enough to subject the compressors to state air quality requirements for pre−construction and operating permits. To date, we have not experienced significant delays or problems in obtaining the required air permits and have been able to operate these compressors in compliance with our permits and applicable federal, state and local laws and regulations without undue cost or burden to our business activities. Another air emission associated with our coalbed methane operations that may be subject to regulation and permitting requirements is particulate matter resulting from construction activities and vehicle traffic. To date, we have not experienced any difficulty complying with environmental requirements related to particulate matter and have not needed to obtain permits relating to particulate matter.

***Atlantic Rim***

The eastern Washakie Basin is currently the subject of the Atlantic Rim EIS being developed by the BLM under the jurisdiction of the Rawlins, Wyoming regional office. The Atlantic Rim EIS covering our coalbed methane leases in the Washakie Basin is currently under way. Completion of the environmental impact statement and issuance of a record of decision is expected during the fourth quarter of 2005.

The BLM has issued an interim drilling policy allowing limited CBM drilling and production activity in the Atlantic Rim project pending completion of the EIS. The interim drilling policy authorizes drilling, completing, and producing no more than 200 wells until completion of the Atlantic Rim EIS. We and our drilling partners have been allocated approximately 165 gross wells of the 200 authorized wells. The interim policy requires the wells to be drilled in nine pods of no more than 24 wells per pod. A pod is defined as two or more production wells with supporting infrastructure, such as access roads, injection wells, product pipelines, water pipelines, power lines and other necessary or ancillary facilities. The Atlantic Rim project contains federally designated threatened and endangered species and two wildlife habitat areas that have been designated as areas of critical environmental concern. Sensitive areas such as critical habitat and archeological sites must be avoided in constructing the pods. Federal and non−federal leases in the Atlantic Rim project are subject to the 200 well limit. To date, we have received BLM and state approval of drilling permits for 72 producing wells, and approval of right−of−ways for five pods.

The BLM may modify the interim drilling policy at any time and the policy, as with any agency decision, is subject to legal challenges by interested parties. The interim policy requires an environmental assessment for each of the nine pods. Public comment is allowed on each environmental assessment, and BLM approval of each environmental assessment must be obtained before pod construction can commence. Several of the environmental assessments have been challenged by environmental groups and individuals. In addition, many of the restrictions, conditions and limitations on our drilling, production and construction activities in the Washakie Basin, including without limitation the number of wells that may be drilled and the timing and location for those future wells, will be specified by the BLM in the final Atlantic Rim EIS record of decision. Finally, conditions and restrictions on drilling, production and construction activities may be imposed through site−specific BLM approvals required for applications for permits to drill and plans of development. As a result, such development activities will remain contingent on BLM approval for several years.

Our eastern Washakie Basin CBM production operations are also subject to Wyoming DEQ regulations and permit requirements. Permits required from the Wyoming DEQ include air emission and produced water discharge permits. To date, we have not experienced any difficulties in obtaining any air permits needed for our Washakie Basin operations from the Wyoming DEQ. Produced water disposal will be limited to subsurface injection in the portion of the Washakie Basin within the Colorado River drainage area. We have received permits for nine produced water injection wells in the Atlantic Rim project. We will need to obtain permits for additional injection wells, in the event that we need additional subsurface disposal capacity.

***Pacific Rim***

The western Washakie Basin is currently the subject to the 1997 updated resource management plan, or RMP, under the jurisdiction of the Rock Springs, Wyoming regional office of the BLM. The Rock Springs RMP currently allows the drilling of up to 250 CBM wells that are not contemplated by a separate EIS. In October 2003, at our request, the BLM began the scoping process for an EA that covers approximately 42,721 acres, including the majority of the 35,679 gross (28,005 net) acres comprising our Pacific Rim project area. The Pacific Rim EA contemplates the drilling of 120 CBM wells in the study area. We received a record of decision on this EA in the third quarter of 2004. Based on information currently available, we anticipate being allocated approximately 80 of the 120 wells in the EA study area. Upon the completion of the 120 authorized wells, a more comprehensive EIS may be required for additional development in the project. We do not believe that an EIS for the Pacific Rim project will be necessary before 2006.

***Powder River Basin***

The Powder River Basin is currently the subject of an EIS that was updated in May 2003. Drilling and production operations on our Powder River Basin leases in Wyoming are subject to environmental rules, requirements and permits issued by federal, state and local regulatory agencies, including the BLM and the Wyoming DEQ. The BLM has imposed environmental limitations and conditions on CBM drilling, production and related construction activities on federal leases in certain specific areas of the Powder River Basin. These conditions and requirements are imposed through a record of decision issued pursuant to an EIS. The BLM may also impose site−specific conditions on development activities, such as drilling and the construction of rights−of−way, before it approves required applications for permits to drill and plans of development. We believe that we have operated our Powder River Basin federal leases in compliance with the BLM’s current requirements.

Our Powder River Basin CBM production operations are also subject to Wyoming DEQ environmental regulations and permit requirements. Permits required from the Wyoming DEQ include air emission and produced water discharge permits. To date, we have not experienced any difficulty in obtaining air quality permits from the Wyoming DEQ. Injection wells are used to dispose of produced water when surface discharge permits cannot be obtained from the Wyoming DEQ. We have three permitted injection wells for our Powder River Basin operations. We may need to permit, drill and operate additional injection wells in the event additional subsurface disposal capacity is needed.

***Wilmington Unit***

The Wilmington unit is located in a mixed light industrial and residential area near the Port of Los Angeles. Field activities include drilling wells to develop our lease acreage and operating a waterflood to maximize crude oil production. Stringent environmental regulations, restrictive permit conditions and the possibility of permit denials from a multiplicity of state, regional and local regulatory agencies may inhibit or add cost to future Wilmington unit development activities. Despite prudent operation and preventative measures, drilling and waterflooding production operations may result in spills and other accidental releases of produced water and injection fluids. Remediation and associated costs from a release of produced water or injection fluids in an urban environment could be significant. This potential liability is accentuated by the location of our Wilmington unit leases near residential areas. To date and to our knowledge, there are no environmentally related lawsuits or other third−party claims or complaints pending against us relating to our interests or activities in the Wilmington unit.

**Operating Hazards And Insurance**

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, including spills or releases of crude oil, produced water and injection fluids, and other potential events which could have a material adverse effect on our business, financial condition and results of operations. Any of these problems could adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, production or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. For some risks, we may elect not to obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs and is not fully covered by insurance, it could have a material adverse effect on our business, financial condition and results of operations.

**Title to Properties**

In most situations, as is customary in the oil and gas industry, only a preliminary title examination is conducted at the time we acquire oil and gas leases covering properties for possible drilling operations. Prior to the commencement of drilling operations, a more complete title examination of the drill site tract often is conducted by independent attorneys. Once production from a given well is established, we prepare a division order title report indicating the proper parties and percentages for payment of production proceeds, including royalties. The level of title examination often differs from property to property. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect the carrying value of our properties.

**Employees**

At December 31, 2004, we had 29 full−time employees. We believe that our relationships with our employees are good. None of our employees are covered by a collective bargaining agreement. From time to time, we use the services of independent consultants to perform various professional services, particularly in the areas of geological, permitting and environmental assessment. Independent contractors often perform well drilling and production operations, including pumping, maintenance, dispatching, inspection and testing.

**Facilities**

Our principal executive offices are located at 489 Fifth Avenue, 32nd Floor, New York, NY 10017, and our telephone number is (212) 697−9660. We lease approximately 4,097 square feet of office space for our

New York office under a lease that expires in 2008. Our oil and gas administrative office in Casper, Wyoming occupies 3,750 square feet under a lease currently being negotiated. In June 2003, we entered into an office lease in Roswell, New Mexico, which expires in May 2005. We believe that suitable additional space to accommodate our anticipated growth will be available in the future on commercially reasonable terms.

**Available Information**

We make available, free of charge through our website, our annual report on Form 10−K, quarterly reports on Form 10−Q, current reports on Form 8−K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after such documents are electronically filed with, or furnished to, the SEC. Our Internet address is www.warrenresources.com.

**Glossary of Abbreviations and Terms**

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and this annual report:

**Adsorption.** The attachment, through physical or chemical−bonding, of gas molecules to the coal surface. The adsorbed gas molecules are trapped within the coal, the stability of which is strongly affected by changes in temperature and pressure.

**AMI.** Area of mutual interest.

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

**Bbl/d.** One Bbl per day.

**Bcf.** One billion cubic feet of natural gas at standard atmospheric conditions.

**Bcfe.** One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

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

**Btu or British thermal unit.** The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

**Coalbed methane (CBM).** Natural gas formed as a byproduct of the coal formation process, which is trapped in coal seams and produced by non−traditional means.

**Completion.** The installation of permanent equipment for the production of oil or natural gas.

**Condensate.** Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

**Desorption.** The detachment of adsorbed gas molecules from the coal surface. See “Adsorption”.

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

**Development well.** A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

**Dewatering.** A coalbed methane well typically begins dewatering with almost all water production and little, or no, natural gas production. The continuous production of water from a well that is dewatering reduces the water reservoir pressure on the coals. The reduced reservoir pressure enables the release of the gas within the coal to the wellbore. This results in an increase in the amount of gas production relative to the amount of water production. Dewatering ceases when peak gas production is reached.

**Dry hole.** A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

**Environmental assessment (EA).** A public document that analyzes a proposed federal action for the possibility of significant environmental impacts. The analysis is required by the National Environmental Policy Act. If the environmental impacts will be significant, the federal agency must then prepare an environmental impact statement.

**Environmental impact statement (EIS).** A detailed statement of the environmental effects of a proposed action and of alternative actions that is required for all major federal actions.

**Exploitation.** The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

**Exploration.** The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

**Exploratory well.** A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

**Farmout or Farmin.** An agreement where the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm−in while the interest transferred by the assignor is a farm−out.

**Field.** An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

**Fracturing.** The technique of improving a well’s production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or gases may more easily flow through the formation.

**Gross Acres.** The total acres in which we own any amount of working interest.

**Gross Wells.** The total number of producing wells in which we own any amount of working interest.

**Horizontal Drilling.** A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

**Identified drilling locations.** Total gross locations specifically identified and scheduled by management as an estimation of our multi−year drilling activities on existing acreage. Our actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

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

**Intangible Drilling Costs.** Expenditures made for wages, fuel, repairs, hauling and supplies necessary for the drilling or recompletion of an oil or gas well and the preparation of such well for the production of oil or gas, but without any salvage value, which expenditures are generally accepted in the oil and gas industry as being currently deductible for federal income tax purposes. Examples of such costs include:

- ground clearing, drainage construction, location work, road making, temporary roads and ponds, surveying and geological works;

• drilling, completion, logging, cementing, acidizing, perforating and fracturing of wells;

• hauling mud and water, perforating, swabbing, supervision and overhead;

• renting horizontal tools, milling tools and bits; and

• construction of derricks, pipelines and other physical structures necessary for the drilling or preparation of the wells.

**Lease.** An instrument which grants to another (the lessee) the exclusive right to enter to explore for, drill for, produce, store and remove oil and natural gas on the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

**MBbl.** One thousand barrels of oil or other liquid hydrocarbons.

**Mcf.** One thousand cubic feet of natural gas at standard atmospheric conditions.

**Mcf/d.** One Mcf per day.

**Mcfe.** One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

**MMbbl.** One million barrels of oil or other liquid hydrocarbons.

**MMBoe.** One million barrels of oil equivalent.

**MMBtu.** Million British thermal units.

**MMcf.** One million cubic feet of natural gas at standard atmospheric conditions.

**MMcf/d.** One MMcf per day.

**MMcfe.** One million cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

**MMcfe/d.** One MMcfe per day.

**Net acres.** Gross acres multiplied by the percentage working interest owned by Warren.

**Net production.** Production that is owned by Warren less royalties and production due others.

**Net wells.** The sum of all the complete and partial well ownership interests (i.e., if we own 25% percent of the working interest in eight producing wells, the subtotal of this interest to the total net producing well count would be two net producing wells).

**NYMEX.** New York Mercantile Exchange.

**Operator.** The individual or company responsible for the exploration, exploitation and production of an oil or natural gas well or lease.

**Overpressured.** A subsurface formation that exerts an abnormally high formation pressure on a wellfore drilled into it.

**Permeability.** The capacity of a geologic formation to allow water, natural gas or oil to pass through it.

**Pod.** A grouping of 10 to 24 wells complete with associated infrastructure, including water disposal wells, gathering and compression.

**Porosity.** The ratio of the volume of all the pore spaces in a geologic formation to the volume of the whole formation.

**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 all states require plugging of abandoned wells.

**PV−10 Value.** The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non−property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization or federal income taxes and discounted using an annual discount rate of 10%.

**Productive well.** A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

**Prospect.** A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

**Proved developed reserves.** Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

**Proved reserves.** The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

**Proved undeveloped reserves (PUD).** Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

**Re−entry.** Entering an existing well bore to redrill or repair.

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

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

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

**Standardized Measure of Discounted Future Net Cash Flows.** The present value of future discounted net cash flows attributed to proved oil and gas properties made by applying year end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) 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, with consideration of future tax rates already legislated) 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% per year to reflect the estimated timing of the future cash flows.

**Tangible Drilling Costs.** Expenditures necessary to develop oil or gas wells, including acquisition, transportation and storage costs, which typically are capitalized and depreciated for federal income tax purposes. Examples of such expenditures include:

- well casings;
- wellhead equipment;
- water disposal facilities;

- metering equipment;
- pumps;
- gathering lines;
- storage tanks;
- gas compression and treatment facilities.

**3−D Seismic.** The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3−D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

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

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

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

**Ultimate recovery.** The total expected recovery of oil and gas from a producing well, leasehold, pool or field.

**Item 3:** ***Legal Proceedings***

*Gotham Insurance Company v. Warren.* In 1998, we and our subsidiary, Warren E&P, Inc., were sued in the 81st Judicial District Court of Frio County, Texas by Stricker Drilling Company, Inc. and Manning Safety Systems to recover the value of lost equipment based on a well blow−out. As a result of the lawsuit, Gotham Insurance Company, Warren E&P's well blow−out insurer, intervened. The suit was settled in 1999 with all parties except Gotham and other underwriters. Gotham paid more than $1.8 million under the insurance policy and is now seeking a refund of approximately $1.8 million, denying coverage, and alleging fraud and misrepresentation and a failure of Warren E&P to act with due diligence and pursuant to safety regulations. Warren E&P countersued for the remaining proceeds under the policy coverage. In the summer and fall of 2000, summary judgments were entered in favor of Warren E&P on essentially all claims except its bad faith claims against Gotham, and Gotham's claims were rejected. Final judgment was rendered by the District Court on May 14, 2001 in Warren E&P's favor for the remaining policy proceeds, interest and attorneys' fees. Gotham appealed the final judgment to the San Antonio Court of Appeals, seeking a refund of approximately $1.5 million. On July 23, 2003, the San Antonio Court of Appeals reversed, in Gotham's favor, the trial court's earlier summary judgment for Warren E&P and remanded the case to the trial court for further proceedings consistent with the San Antonio Court of Appeals' decision. A hearing was held on December 17, 2004 to consider the parties' motions to determine both the amount of actual loss incurred by Gotham and the amount of judgment liability to be paid by Warren and Warren E&P. On January 4, 2005, the Company received an order of the trial court that Warren and Warren E&P were obligated to repay Gotham $1.8 million, along with attorneys' fees and statutory interest estimated at $966,000. At December 31, 2004, Warren recorded a provision for $1,800,000 relating to this settlement. On January 31, 2005, Warren filed a Motion for New Trial before the trial court. If our Motion for New Trial is not granted, Warren intends to appeal the order of the trial court to the Texas Court of Appeals. Although we believe that we have meritorious grounds for the appeal, if our appeal is unsuccessful, we will pay the restitution to Gotham as ordered by the trial court.

We are also a party to legal actions arising in the ordinary course of our business. In the opinion of our management, based in part on consultation with legal counsel, the liability, if any, under these claims is either adequately covered by insurance or would not have a material adverse effect on us.

**Item 4:** ***Submission of Matters to a Vote of Security Holders***

No matters were submitted to a vote of security holders during the fourth quarter of the fiscal year 2004.

## PART II

**Item 5:** ***Market for the Registrant's Common Equity and Related Stockholder Matters***

**Market Information.**

The Company conducted its initial public offering on December 16, 2004 at $7.50 per share of common stock. Our common stock has traded on the Nasdaq National Market under the symbol "WRES" since December 17, 2004. The following table sets forth, for the period indicated, the high and low closing sales prices for our common stock as reported by the Nasdaq National Market:

| | Common Stock Price | |
|---|---|---|
| | High | Low |
| Quarter ended December 31, 2004 (commencing December 17, 2004) | $ 10.00 | $ 8.00 |

On March 15, 2005, the closing sales price for our common stock as reported by Nasdaq was $11.19 per share.

**Holders**

As of March 15, 2005 there were approximately 3,060 holders of our common stock.

**Dividend Policy**

We have never paid or declared any cash dividends on our common stock. We currently intend to retain earnings, if any, to finance the growth and development of our business and we do not expect to pay any cash dividends on our common stock in the foreseeable future. Payment of future cash dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion.

**Securities Authorized for Issuance Under Compensation Plans**

The table below includes information about our equity compensation plans as of December 31, 2004:

| | Number of Shares Authorized for Issuance under Plan | Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights | Weighted−Average Exercise Price of Outstanding Options, Warrants and Rights | Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans |
|---|---|---|---|---|
| 2000 Equity Incentive Plan | 1,975,000 | 710,500 | $ 4.74 | 1,264,500 |
| 2001 Stock Incentive Plan | 2,500,000 | 847,956 | $ 7.37 | 1,465,988 |
| 2001 Key Employee Stock Incentive Plan | 2,500,000 | 1,066,750 | $ 4.91 | 1,433,250 |
| Total | 6,975,000 | 2,625,206 | $ 5.66 | 4,163,738 |

**Use of Proceeds**

The Securities and Exchange Commission declared our registration statement, filed on Form S−1 (SEC File No. 333−118535) under the Securities Act in connection with the initial public offering of our common stock, effective on December 16, 2004, covering an aggregate of 10,925,000 shares of common stock, including shares that were issued upon the exercise by the underwriters of their over−allotment option. The managing underwriter in our initial public offering was KeyBanc Capital Markets. The aggregate gross proceeds from the shares of common stock sold were approximately $81.9 million. In connection with the offering, we paid the underwriters a commission of approximately $5.7 million and incurred offering expenses of approximately $1.0 million, none of which were paid, directly or indirectly, to our directors, officers, 10% or greater shareholders or affiliates. After deducting the underwriters' commission and the estimated offering expenses, we received net proceeds of approximately $75.2 million from the offering, which were deposited into an interest bearing money market account. None of these proceeds were used to fund operations in the fourth quarter of 2004.

**Item 6:** ***Selected Consolidated Financial Data***

The following tables present selected financial and operating data for Warren and its subsidiaries as of and for the periods indicated. You should read the following selected data along with “Item 7−Management’s Discussion and Analysis of Financial Condition and Results of Operations,” our financial statements and the related notes and other information included in this annual report. The selected financial data as of December 31, 2004, 2003, 2002, 2001 and 2000 has been derived from our financial statements, which were audited by Grant Thornton LLP, independent auditors, and were prepared in accordance with accounting principles generally accepted in the United States of America. The historical results presented below are not necessarily indicative of the results to be expected for any future period.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| **Consolidated Statement of Operations Data:** | | | | | |
| Revenues: | | | | | |
| Turnkey contracts with affiliated partnerships | $ 10,530 | $ 11,301 | $ 5,841 | $ 30,103 | $ 33,985 |
| Oil & gas sales from marketing activities | 6,171 | 5,621 | 11,272 | 14,867 | 15,421 |
| Well services | 1,070 | 1,168 | 1,895 | 5,574 | 4,297 |
| Oil & gas sales | 6,454 | 5,717 | 593 | 948 | 200 |
| Total revenues | 24,225 | 23,807 | 19,601 | 51,492 | 53,903 |
| Costs and operating expenses: | | | | | |
| Turnkey contracts | 12,932 | 7,285 | 4,965 | 25,953 | 22,783 |
| Cost of oil and gas purchased from affiliated partnerships | 6,028 | 5,500 | 11,121 | 15,299 | 15,800 |
| Well services | 673 | 662 | 839 | 3,519 | 3,168 |
| Production and exploration | 3,935 | 3,812 | 1,326 | 568 | 355 |
| Depreciation, depletion, amortization and impairment | 4,023 | 3,249 | 9,930 | 14,462 | 3,065 |
| Contingent repurchase obligation | — | — | (3,065) | 3,319 | — |
| General and administrative | 8,116 | 4,496 | 6,278 | 5,485 | 6,416 |
| Total costs and operating expenses | 35,707 | 25,004 | 31,394 | 68,605 | 51,587 |
| Income (loss) from operations | (11,482) | (1,197) | (11,793) | (17,113) | 2,316 |
| Other income (expense): | | | | | |
| Interest and other income | 2,089 | 1,340 | 5,258 | 1,977 | 2,457 |
| Interest expense | (494) | (1,528) | (6,313) | (5,776) | (6,968) |
| Gain on sale of oil and gas properties | 120 | 494 | 4,287 | — | — |
| Net gain (loss) on investment | (43) | 21 | 464 | (10) | 587 |
| Total other income (expense) | 1,672 | 327 | 3,696 | (3,809) | (3,924) |
| Loss before income taxes, extraordinary item and cumulative effect of change in accounting principle | (9,810) | (870) | (8,097) | (20,922) | (1,608) |
| Income tax expense (benefit) | (59) | 129 | (471) | 152 | (412) |
| Loss before minority interest and cumulative change in accounting principle | (9,751) | (999) | (7,626) | (21,074) | (1,196) |
| Minority interest | (209) | (112) | — | — | — |
| Net loss before change in accounting principle | (9,960) | (1,111) | (7,626) | (21,074) | (1,196) |
| Cumulative effect of change in accounting principle | — | (88) | — | — | — |

| | | | | | |
|---|---|---|---|---|---|
| Net loss | (9,960) | (1,199) | (7,626) | (21,074) | (1,196) |
| Preferred dividends and accretion | 6,591 | 4,562 | 16 | — | — |
| Net loss applicable to common stockholders | $ (16,551) | $ (5,761) | $ (7,642) | $ (21,074) | $ (1,196) |
| Basic and diluted loss per common share | $ (0.84) | $ (0.34) | $ (0.44) | $ (1.20) | $ (0.10) |
| Weighted average shares outstanding basic and diluted | 19,739,048 | 16,827,857 | 17,339,869 | 17,532,882 | 12,461,814 |

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| **Consolidated Statement of Cash Flows Data:** | | | | | |
| Net cash provided by (used in): | | | | | |
| Operating activities | $ (4,507) | $ 5,278 | $ (6,101) | $ (15,712) | $ 10,659 |
| Investing activities | (29,033) | (13,524) | 5,317 | (17,635) | (19,012) |
| Financing activities | 108,931 | 9,591 | 1,045 | (2,700) | 26,701 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2004 | 2003 | 2002 | 2001 | 2000 |
| **Balance Sheet Data:** | | | | | |
| Cash and cash equivalents | $ 99,921 | $ 24,529 | $ 23,184 | $ 22,924 | $ 58,970 |
| Total assets | 246,911 | 151,054 | 108,262 | 94,900 | 128,649 |
| Total long−term debt (including current maturities) | 50,038 | 49,916 | 56,202 | 61,880 | 60,447 |
| Stockholders' equity (deficit) | 157,569 | 56,394 | 7,002 | (6,434) | 14,876 |

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

*The discussion and analysis that follows should be read together with the "Selected Consolidated Financial Data" and the accompanying financial statements and notes related thereto that are included elsewhere in this annual report. It includes forward−looking statements that may reflect our estimates, beliefs, plans and expected performance. The forward−looking statements are based upon events, risks and uncertainties that may be outside our control. Our actual results could differ significantly from those discussed in these forward−looking statements. Factors that could cause or contribute to these differences include but are not limited to, market prices for natural gas and oil, regulatory changes, estimates of proved reserves, economic conditions, competitive conditions, development success rates, capital expenditures and other uncertainties, as well as those factors discussed below and elsewhere in this annual report, including in "Risk Factors" and "Cautionary Note Regarding Forward−Looking Statements", all of which are difficult to predict. As a result of these assumptions, risks and uncertainties, the forward−looking matters discussed may not occur.*

### Overview

We are a growing independent energy company engaged in the exploration and development of domestic onshore natural gas and oil reserves. We focus our efforts primarily on the exploration and development of coalbed methane, or CBM, properties located in the Rocky Mountain region and on our waterflood oil recovery program in the Wilmington Townlot Unit, or the Wilmington unit, in the Wilmington field within the Los Angeles Basin of California. As of December 31, 2004, we owned natural gas and oil leasehold interests in approximately 267,234 gross (147,984 net) acres, 94% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains. Our total net proved reserves are located on approximately 6% of our net acreage.

From our inception in 1990 through 2003, we functioned principally as the sponsor of privately placed drilling programs and joint ventures. Under these programs, we contribute drilling locations, pay tangible drilling costs and provide turnkey drilling services, natural gas marketing services and well services to the drilling partnerships and retain an interest in the wells. Historically, a substantial portion of our revenue was attributable to these turnkey drilling services.

From December 2002 to March 2003, 13 drilling programs formed from 1994 though 1997 converted from Delaware limited partnerships to Delaware limited liability companies. As a result of these conversions, we have issued an aggregate of 3,341,559 restricted convertible preferred shares to the 13 LLCs as additional capital contributions and received as consideration additional standard membership interests in the LLCs. This increased our pro rata beneficial interests in the oil and gas wells owned by the LLCs. Also during 2003, we issued an aggregate of 1,048,336 restricted convertible preferred shares to two joint ventures as additional capital contributions and received as consideration additional joint venture interests in the joint ventures, which increased our pro rata beneficial interests in the oil and gas wells owned by the joint ventures.

We anticipate that revenue from turnkey drilling services will become increasingly less material to our business in the future. Our future revenue growth is primarily dependent on our ability to increase our oil and gas reserves and production. We plan to participate in all our drilling activities on a pro rata basis with our drilling programs until we have performed our obligations under the turnkey drilling contracts related to our existing deferred income of approximately $11.9 million as of December 31, 2004. We plan to participate with our drilling programs in 2 net wells within the Wilmington unit during 2005. After we have performed our obligations under the turnkey drilling contracts we intend to invest more of our own capital in drilling operations in order to accelerate the growth of our production and reserves. We also anticipate that any future drilling activities that we undertake with third parties will be through joint ventures and similar arrangements.

The schedule below reflects revenue and expense from gas and oil sales and from turnkey contracts for the years ended December 31, 2004 and 2003.

| | 2004 | 2003 |
|---|---|---|
| Oil and gas sales | $ 6,454,334 | $ 5,717,814 |
| Production and exploration expense | 3,935,137 | 3,811,595 |
| Gross margin | $ 2,519,197 | $ 1,906,219 |

| | 2004 | 2003 |
|---|---|---|
| Turnkey contract revenue with affiliated partnerships | $ 10,529,883 | $ 11,300,646 |
| Turnkey contract expense | 12,932,124 | 7,284,653 |
| Gross margin | $ (2,402,241) | $ 4,015,993 |

We estimate that the completion of drilling activities on behalf of our drilling programs and the subsequent commencement of drilling activities primarily for our own account will occur by the fourth quarter of 2005. We anticipate that, depending upon our drilling results, our production revenue may not be sufficient for us to achieve positive cash flow from operating activities on or before the end of 2006. Even if we are able to achieve positive cash flow from operating activities on or before the end of 2006, which we cannot assume, we may not be able to achieve positive cash flow from operating activities on a cumulative basis for 2006. To the extent we are able to achieve increases in natural gas and oil production revenue, we also will experience increases in production and exploration expense.

Our capital expenditure budget for 2005 is $37.6 million, which includes participation in the drilling of 100 gross (55.9 net) wells. At the present time, we are concentrating our drilling activities in our Atlantic Rim and Pacific Rim projects of the Washakie Basin, where we are planning to participate in the drilling of 40 gross wells and 19 gross wells, respectively, during 2005. Also during 2005, we expect to drill 29 gross wells in the Wilmington unit in the Los Angeles Basin and 12 gross wells in the Powder River Basin. Although we expect our activities in the Powder River Basin to continue to produce additional revenues, we already have conducted drilling activities on a substantial part of our acreage in that project.

Our activities in the Wilmington unit have been delayed since 1999 because our interests in this unit were the subject of arbitration with Magness Petroleum, our joint venture partner. In November 2004, we entered into a purchase and sale agreement and a settlement agreement and release with Magness Petroleum for the purpose of settling our disputes and ending arbitration. Pursuant to the purchase and sale agreement, Magness Petroleum and its affiliate agreed to sell, and we agreed to buy, all the interests of Magness Petroleum and its affiliate in the Wilmington unit, together with existing wells, equipment and jointly owned surface properties. Under the settlement agreement and release all awards, findings and/or judgments, including a $1.6 million award in our favor, was vacated and all proceeding were dismissed. In exchange for such interests and assets, we paid a cash purchase price of $14.8 million and assumed certain liabilities and obligations of Magness Petroleum and its affiliate associated with the Wilmington unit. The purchase and sale agreement closed on January 31, 2005.

Incorporating the settlement and acquisition with Magness Petroleum, our estimated total proved natural gas and oil reserves, as of December 31, 2004, adjusted as if the acquisition had occurred on December 31, 2004, would be approximately 128.9 Bcfe and the PV−10 value of these reserves would be approximately $307 million.

Compared with the development of our CBM properties, we anticipate that development of our oil properties in the Wilmington unit could have a more immediate impact on our cash flows. We also anticipate that we will be able to conduct drilling operations in the Wilmington unit on a year−round basis without weather−induced or other drilling delays as may occur in the Rocky Mountain areas where our CBM properties are located.

A substantial portion of our economic success depends on factors over which we have no control, including natural gas and oil prices, operating costs, and environmental and other regulatory matters. In our planning process, we focus on maintaining financial flexibility together with a low cost structure in order to reduce our vulnerability to these uncontrollable factors.

**Critical Accounting Policies**

***Oil and Gas Producing Activities***

We use the successful efforts method of accounting for oil and gas properties. Under this methodology, costs incurred to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on our experience of successful drilling, terms of leases and historical lease expirations.

Capitalized costs of producing oil and gas properties are depleted by the units−of−production method on a field−by−field basis. Lease costs are depleted using total proved reserves while lease equipment and intangible development costs are depleted using proved developed reserves. Our proved properties are evaluated on a field−by−field basis for impairment. An impairment loss is indicated whenever net capitalized costs exceed expected future net cash flow based on engineering estimates. In this circumstance, we recognize an impairment loss for the amount by which the carrying value of the properties exceeds the estimated fair value based on discounted cash flow.

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion and amortization are eliminated from the property accounts, and the resulting gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depletion and amortization with a resulting gain or loss recognized in earnings.

On the sale of an entire interest in an unproved property, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Our estimate of proved reserves is based on the quantities of oil and gas that engineering and geological analysis demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Our reserve estimates and the projected cash flows are derived from these reserve estimates, in accordance with SEC guidelines by an independent engineering firm based in part on data provided by us. The accuracy of our reserve estimates depends in part on the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates.

***Revenue Recognition***

Affiliated partnerships enter into agreements with us to drill wells to completion for a fixed price. We, in turn, enter into drilling contracts primarily with unrelated parties to drill wells on a day work basis. Therefore, if problems are encountered on a well, the cost of that well will increase and gross profit will decrease and could result in a loss on the well. We recognize revenue from the turnkey drilling agreements on a proportional performance method as services are performed. This involves management making judgments and estimates as to their various stage of completion of each well based on the review of drilling logs, status reports from engineers and historical experience in completing similar wells. When estimates of future revenues and expenses on a specific contract indicate a loss will be incurred, the total estimated loss is accrued.

Oil and gas sales result from undivided interests held by us in various oil and gas properties. Sales of natural gas and oil produced are recognized when delivered to or picked up by the purchaser. Oil and gas sales from marketing activities result from sales by us of oil and gas produced by affiliated joint ventures and partnerships and are recognized when delivered to purchasers.

***Capitalized Interest***

Statement of Financial Accounting Standards No. 34, “Capitalization of Interest Cost”, provides standards for the capitalization of interest cost as part of the historical cost of acquiring assets. Costs of investments in unproved properties on which exploration or development activities are in progress or are the subject of pending litigation qualify for capitalization of interest. Capitalized interest is calculated by multiplying our weighted−average interest rate on debt by the amount of qualifying costs. Capitalized interest cannot exceed gross interest expense.

***Asset Retirement Obligations***

In June 2001, the Financial Accounting Standard Board issued Statements of Financial Accounting Standards No. 143, or SFAS 143, “Accounting for Asset Retirement Obligations”, which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long−lived asset. This statement is effective for fiscal years beginning after June 15, 2002. We adopted SFAS 143 on January 1, 2003 and recorded a net asset of $557,000, a related liability of $645,000, using a 10% discount rate, and a cumulative effect on change in accounting principle on prior years of $88,000. As of December 31, 2002, the Company had an allowance for asset retirement obligations of $434,000. During 2004 and 2003, the asset retirement liability was increased by approximately $53,000 and $62,000, respectively, as a result of accretion and recorded as interest expense. Also during 2004 and 2003, we sold certain non−strategic oil and gas properties deemed not commercially productive, which resulted in a decrease to the asset retirement liability of approximately $73,000 and $255,000, respectively. We have treasury bonds held in escrow with a fair market value as of December 31, 2004 of $2,766,000. These treasury bonds are legally restricted for potential plugging and abandonment liabilities in the Wilmington unit.

**New Accounting Pronouncement**

In December 2004, the FASB issued SFAS No. 123(R), “Share−Based Payment”. This Statement revises SFAS No. 123, “Accounting for Stock−Based Compensation” and supersedes APB Opinion No. 25, “Accounting for Stock Issued to Employees.” SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share−based payment transactions. SFAS No. 123(R) requires companies to recognize in the statement of operations the cost of employee services received in exchange for awards of equity instruments based on the grant−date fair value of those awards. This Statement is effective as of the first reporting period that begins after June 15, 2005. Accordingly, the Company will adopt SFAS No. 123(R) in its third quarter of fiscal 2005. The Company is currently evaluating the provisions of SFAS No. 123(R) and the impact that it will have on its share based employee compensation programs.

**Results of Operations**

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

*Turnkey contract revenue and expenses*

Turnkey contract revenue decreased $800,000 during 2004 to $10.5 million, a 7% decrease compared to the preceding year. Additionally. Turnkey contract expense increased $5.6 million during 2004 to $12.9 million, a 78% increase compared to 2003.

Net loss from turnkey activities was $2.4 million for 2004. This compared to net income of $4.0 million for 2003. This net loss resulted from a significant increase in drilling costs, such as drilling rig rates and steel prices. In addition, net income decreased during 2004 as a result of drilling Washakie wells with lower profit margins in 2004 as compared to drilling shallow re−entry wells in 2003 with higher profit margins.

*Oil and gas sales and costs from marketing activities*

Oil and gas sales from marketing activities increased $600,000 in 2004 to $6.2 million, a 10% increase compared to 2003. Cost of oil and gas marketing activities increased $500,000 in 2004 to $6.0 million, a 10% increase compared to 2003. Oil and gas production from the wells in the drilling programs in which we earn a marketing fee for 2004 and 2003 was 1.4 Bcfe and 1.2 Bcfe, respectively. The average price per Mcfe during 2004 and 2003 was $5.26 and $3.92, respectively.

The gross profit from marketing activities for both 2004 and 2003 was $100,000.

*Well service activities*

Well services revenue decreased $100,000 in 2004 to $1.1 million, an 8% decrease compared to 2003. Well services expense increased $11,000 in 2004 to $700,000.

Gross profit from well services activities was $400,000 and $500,000, respectively for 2004 and 2003. The decrease in gross profit during 2004 resulted from lower supervision and overhead activity during 2004.

*Oil and gas sales*

Revenue from oil and gas sales increased $700,000 in 2004 to $6.5 million, a 13% increase compared to 2003. The increase was offset by a retroactive adjustment which reduced our oil and gas sales in accordance with the reduction in our working interest percentage in the Sun Dog unit in the Washakie Basin. In accordance with the Washakie Basin unit Operating Agreement, our working interest percentage increases or decreases as the field unit expands.

*Net gain (loss) on investments*

Net loss on investments was $42,000 for 2004. Net gain on investments was $22,000 during 2003. Our investments consist primarily of zero coupon U.S. treasury bonds held in our inventory. Fluctuations in net gain or loss on investments resulted from changes in long term interest rates.

*Interest and other income*

Interest and other income increased $700,000 in 2004 to $2.1 million, a 56% increase compared to 2003. The increase results from the receipt of accounts receivable which were previously written off.

*Gain on sale of assets*

The $500,000 gain on the sale of assets in 2003 resulted from the sale of certain non−strategic properties in New Mexico.

*Production & exploration expenses*

Production and exploration expense increased $100,000 in 2004 to $3.9 million, a 3% increase compared to 2003. This increase resulted from an increase in the volume of oil and gas sales. Additionally, we incurred increased lease operating expenses related to our Washakie Basin properties. The increase was offset by a retroactive adjustment which reduced our production and exploration expense in accordance with the reduction in our working interest percentage in the Sun Dog unit in the Washakie Basin.

*Depreciation, depletion, amortization and impairment*

Depreciation, depletion, amortization and impairment expense increased $800,000 for 2004 to $4.0 million, a 24% increase compared to last year. This increase represents a higher cost basis in oil and gas properties in 2004 due to the recapitalization of our drilling programs, as compared to 2003, resulting in a higher depletion expense. Additionally, this increase resulted from impairment expense of $1.0 million and $300,000 in 2004 and 2003, respectively. These increases were offset by a decrease in expense resulting from the expiration of certain leases.

*General and administrative expenses*

General and administrative expenses increased $3.6 million in 2004 to $8.1 million, an 81% increase compared to last year. This increase resulted from recording a liability relating to the Gotham lawsuit totaling $1.8 million. See “Business — Legal Proceedings”. Additionally, this increase reflects an increase in legal fees relating to our California property. See “Business — Legal Proceedings”. Lastly, this increase reflects an increase of $1.2 million resulting from allocating of certain expenses to general and administrative expense during 2004 instead of turnkey expense. As the Company focuses on drilling more for its own account, less G&A expense will be charged to turnkey expense in the future periods.

*Interest Expense*

Interest expense decreased $1.0 million in 2004 to $500,000, a 68% decrease compared to last year. This decrease reflects an increase in the amount of interest capitalized on our Wyoming and California properties due to the recapitalization of our drilling programs.

*Income Taxes*

We follow the provisions of Statements of Financial Accounting Standards No. 109, “Accounting for Income Taxes”, which provides for recognition of a deferred tax liability or asset for temporary differences, operating loss carryforwards, statutory depletion carryforwards and tax credit carryforwards net of a valuation allowance. The temporary differences consist primarily of depreciation, depletion and amortization of intangible drilling costs, unrealized gains on investments and our investment basis in oil and gas partnerships.

As of December 31, 2004, we had a net operating loss carryforward of approximately $76 million. Our net operating loss carryforwards expire in 2012 and subsequent years.

***Year Ended December 31, 2003 Compared To Year Ended December 31, 2002***

*Turnkey contract revenue and expenses*

Turnkey contract revenue increased $5.5 million in 2003 to $11.3 million, a 93% increase compared to 2002. Additionally, turnkey contract expense increased $2.3 million during 2003 to $7.3 million, a 47% increase compared to 2002. These increases resulted from a higher level of drilling activity during 2003 compared to 2002. The level of drilling activity is affected by many factors including obtaining the requisite governmental permits necessary to commence drilling on the leases. Additionally, during the fourth quarter of 2002, we entered into a joint venture with Anadarko whereby we sold partial interests in wells that had been previously allocated to drilling programs. As a result, during the fourth quarter of 2002, previously recognized turnkey revenue was reversed. During 2003, we were able to drill 38 gross and 24.3 net wells on behalf of the drilling programs.

Gross profit from turnkey activities was $4.0 million or 36% for 2003. This compares to gross profit of $876,000 or 15% for 2002. The increase in gross profit percentage during 2003 results from drilling certain wells more economically than the corresponding period of 2002 and changes in the working interests of various wells in our drilling programs resulting from the recapitalization of our drilling programs in 2002.

*Oil and gas sales and costs from marketing activities*

Oil and gas sales from marketing activities decreased $5.7 million in 2003 to $5.6 million, a 50% decrease compared to the previous year. Cost of oil and gas marketing activities decreased $5.6 million in 2003 to $5.5 million, a 51% decrease compared to 2002. These decreases primarily resulted from the recapitalizations of our drilling programs in 2002, whereby we now receive oil and gas production previously allocated to drilling programs. Oil and gas production from the wells in the drilling programs in which we earn a marketing fee for 2003 and 2002 was 1.2 Bcfe and 3.5 Bcfe, respectively. This decrease was offset by higher average gas prices. The average price per Mcfe during 2003 and 2002 was $3.92 and $2.40, respectively.

The gross profit from marketing activities for 2003 was $120,000 as compared to $151,000 in the same period of the previous year.

*Well services activities*

Well services revenue decreased $728,000 in 2003 to $1.2 million, a 38% decrease compared to the preceding year. Well services expense decreased $177,000 for 2003 to $662,000, a 21% decrease compared to 2002. The decreases in well services revenue resulted from the sale of certain assets of our drilling subsidiary, CJS Pinnacle Petroleum LLC on February 14, 2002, for total consideration of $4.2 million. Well services revenue from CJS Pinnacle Petroleum LLC was approximately $400,000 during the first quarter of 2002. Following the sale, Pinnacle ceased operations. Additionally, certain well services revenue approximating $300,000 earned on drilling program wells during 2002 was not earned in 2003. We obtained oil and gas interests from our drilling programs in these wells through the recapitalization of our drilling programs in 2002.

*Oil and gas sales*

Revenue from oil and gas sales increased $5.1 million in 2003 to $5.7 million, an 865% increase compared to the previous year, due to increased ownership in our drilling programs. We obtained oil and gas interests from our drilling programs as a result of the recapitalization of our drilling programs in 2002. Our share of pre−payout production from drilling programs formed subsequent to 1998 is generally 25% of the production allocated to these drilling programs.

*Net gain on investments*

Net gain on investments was $21,000 for 2003 and $464,000 for 2002. Investments consist primarily of zero coupon U.S. treasury bonds held in our inventory. Fluctuations in net gain or loss on investments resulted from changes in long−term interest rates.

*Interest and other income*

Other income decreased $3.9 million in 2003 to $1.3 million, a 74% decrease compared to 2002. During 2002, our executive vice president, James C. Johnson Jr., died. As a result, we received key man life insurance proceeds of $3.8 million.

*Gain on sale of assets*

The gain on sale of assets was $494,000 in 2003 compared to $4.3 million in 2002. The $494,000 gain in 2003 resulted from the sale of certain non−strategic properties in New Mexico during the third quarter of 2003. The $4.3 million gain in 2002 resulted from the sale of certain interests in our Atlantic Rim CBM reserves to Anadarko.

*Production & exploration expenses*

Production and exploration expense increased $2.5 million in 2003 to $3.8 million, a 188% increase compared to the previous year. This resulted from increased ownership in our drilling programs. We obtained oil and gas interests from our drilling programs as a result of the recapitalization of our drilling programs in 2002. Additionally, a plugging and abandonment liability of $1.2 million was reversed during the third quarter of 2002.

*Depreciation, depletion, amortization and impairment*

Depreciation, depletion, amortization and impairment expense decreased $6.7 million for 2003 to $3.2 million, a 67% decrease compared to the previous year. During 2002, we recorded impairment expense totaling $9.3 million relating to certain properties primarily in Texas and Montana. This compares to impairment expense recorded in 2003 of $1.6 million related to expiring leases in the Atlantic Rim Project in the Washakie Basin in Wyoming.

*General and administrative expenses*

General and administrative expenses decreased $1.8 million in 2003 to $4.5 million. During 2002, we wrote off approximately $900,000 of previously capitalized offering expenses. Additionally, the decrease resulted from a reduction in the number of employees employed during 2003 compared to 2002.

*Interest expense*

Interest expense decreased $4.8 million in 2003 to $1.5 million, a 76% decrease compared to the previous year. Primarily, this decrease reflects an increase in the amount of interest of $4.3 million capitalized to our Wyoming and California properties.

*Contingent repurchase obligation*

Repurchase obligation expense of $3.3 million was recorded in 2001 based on pricing at March 15, 2002. The repurchase obligation expense was reversed during the first quarter of 2002. The determination of whether a repurchase liability exists is based upon estimates of future net cash flows from reserve studies prepared by petroleum engineers compared to the potential repurchase of drilling program units. Significant decreases in natural gas and oil prices at December 31, 2001 lowered the estimated future cash flows when compared to future potential repurchase obligations. As a result, a repurchase liability and a repurchase obligation expense of $3.3 million was recorded in 2001.

**Liquidity and Capital Resources**

Our primary source of liquidity since our formation has been the private sale of our equity and debt securities. These private placements primarily were made through a network of independent broker dealers. Since 1992, we sponsored 31 drilling programs that raised an aggregate of approximately $228.0 million. Additionally, we have raised $71.6 million through the issuance of our debt securities and $174.1 million through the issuance of shares of our common and preferred stock. In our drilling programs, we fund the costs associated with acreage acquisition and the tangible portion of drilling activities, while investors in the drilling programs fund all intangible drilling costs. Our primary use of capital has been for the acquisition, development and exploration of our natural gas and oil properties. Additional uses of capital include the payment of dividends on our preferred stock, sinking fund requirements related to debentures and operating losses from operations.

During the first eleven months of 2004, we raised $41.8 million from sales of our common stock and warrants, and through the exercise of stock options. On December 16, 2004, we sold 9,500,000 shares of common stock in an initial public offering for aggregate gross proceeds of $71.25 million. After deducting the underwriters' commission and offering expenses, we received net proceeds of $65.3 million. On December 22, 2004, the underwriters exercised their over−allotment option for an additional 1,425,000 shares of our common stock for additional gross proceeds of $10.7 million and net proceeds of $9.9 million, after deducting the underwriters' commission and offering expenses.

During 2003, we raised $6.4 million through the private placements of interests in our drilling program. Cumulatively, we raised $11.8 million during fiscal years 2003 and 2002 through the private placements of interests in our drilling programs. During 2003, we raised $15.8 million through the private placements of our series A 8% cumulative convertible preferred stock. Cumulatively, we raised $144.2 million during fiscal years 2004, 2003 and 2002 through the private placements of our debt or equity securities.

*Cash Flow from Operating Activities*

Net cash used in operating activities was $4.5 million for 2004. This compares to net cash provided by operating activities of $5.3 million in 2003 and net cash used in operating activities of $6.1 million in 2002. Primarily, in prior periods, increases and decreases in net cash flows from operating activities resulted from turnkey contract operations with our drilling programs.

Our most material commitment of funds for 2004 relates to our drilling programs. Our deferred income balance relating to our drilling commitments totaled $11.9 million at December 31, 2004. We expect to drill the wells allocated to drilling programs and satisfy our related drilling obligations by the fourth quarter of 2005.

**2005 Capital Expenditure Program**

Our total net capital budget spending program for 2005 is $37.6 million, exclusive of the intangible turnkey drilling costs allocable to our participating drilling programs. The majority of these estimated expenditures relate to the development of our Atlantic Rim and Pacific Rim projects in the Rocky Mountains and the development of our oil reserves in the Wilmington unit. The development of these properties focuses our resources on the primary objective to increase production volumes and cash flow. For 2005, we plan to participate in the drilling of 40 gross (11.4 net) wells in the Atlantic Rim, 19 gross (9.9 net) wells in the Pacific Rim and 12 gross (6.0 net) wells in the Powder River Basin projects. Additionally, we plan to undertake the drilling of 29 gross (28.6 net) wells in the Wilmington unit. These spending programs and other cash requirements will be funded by existing cash balances, cash flow from operations and proceeds from our initial public offering. The final determination regarding whether to drill the budgeted wells referred to above is dependent upon many factors including:

- the availability of sufficient capital resources;
- the ability to acquire proper governmental permits and approvals; and
- economic and industry conditions at the time of drilling such as prevailing and anticipated energy prices and the availability of drilling equipment.

**Debentures**

As of December 31, 2004, we had $46.5 million of debentures of which $37.5 million are convertible into our common shares and $9.0 million are not convertible. On January 12, 2005 and January 13, 2005, we called the 2007 and 2017 sinking fund debentures, with outstanding balances at December 31, 2004 of $9.0 million and $5.0 million respectively. These debentures will be redeemed on March 31, 2005 at a premium of 2% for the 2007 bonds and 6% for the 2017 bonds. Additionally, another $9.0 million of our debentures are callable at our option at premiums of 2% to zero ratably from 2005 to 2007, and $5.0 million are generally callable at premiums of 6% to zero ratably from 2005 to 2011.

Further, all convertible debentures are callable by us if the average bid price of our common shares publicly trade at 133% or greater of the respective conversion price of the debentures for at least 90 consecutive trading days. In such an event, debentures not converted may be called by us upon 60 days notice at a price of between 100% and 110% par value plus accrued interest.

We have issued secured debentures and sinking fund debentures. The principal of the secured debentures is secured at maturity by zero coupon U.S. treasury bonds previously deposited into an escrow account equaling the par value of the debentures maturing on or before the due date of the debentures. The principal of the sinking fund debentures is required to be secured by equal annual deposits of zero coupon U.S. treasury bonds, which shall be sufficient in the aggregate to fund repayment of the principal of the outstanding debentures at their respective maturity dates.

The table below reflects the outstanding debentures by issue, the fair market value of the zero coupon U.S. treasury bonds held in escrow on behalf of the debentures holders and the estimated cash outlay for the payment of debenture interest for 2005. The conversion prices listed below will increase in the future for certain debentures.

| Debentures (In thousands, except for conversion prices) | Outstanding at December 31, 2004 | Conversion Price as of December 31, 2004 | Fair Market Value of U.S. Treasuries | Estimated Debenture Interest for 2005 |
|---|---|---|---|---|
| 12% Sinking Fund Debentures due December 31, 2007 | $ 9,036 | n/a | $ 4,121 | $ 271 |
| 12% Secured Fund Debentures due December 31, 2009 | 770 | $ 9.00 | 647 | 92 |
| 12% Secured Fund Debentures due December 31, 2010 | 1,700 | 9.00 | 1,362 | 204 |
| 13.02% Sinking Fund Debentures due December 31, 2010 | 14,372 | 5.00 | 5,760 | 1,871 |
| 13.02% Sinking Fund Debentures due December 31, 2015 | 11,633 | 8.00 | 2,512 | 1,515 |
| 12% Secured Fund Debentures due December 31, 2016 | 1,305 | 9.00 | 751 | 157 |
| 12% Sinking Fund Debentures due December 31, 2017 | 5,040 | 15.00 | 762 | 151 |
| 12% Secured Fund Debentures due December 31, 2020 | 1,485 | 25.00 | 673 | 178 |
| 12% Secured Fund Debentures due December 31, 2022 | 1,136 | 25.00 | 460 | 136 |
| | $ 46,477 | | $ 17,048 | $ 4,575 |

**Preferred Stock**

As of December 31, 2004, we had 6,560,809 shares of convertible preferred stock issued and outstanding.

Dividends and accretion on preferred shares totaled $6.7 million and $4.6 million for the years ended December 31, 2004 and 2003, respectively.

**Contractual Obligations**

The contractual obligations table below assumes the maximum amount is tendered each year, net of the effects of the sinking fund requirements. The table does not give effect to the conversion of any bonds to common stock which would reduce payments due. As described in more detail in the “Debentures” section above, all debentures are secured at maturity, or partially secured at maturity, by zero coupon U.S. treasury bonds deposited into an escrow account equaling the par value of the debentures maturing on or before the maturity of the debentures. The table below reflects the release of U.S. treasury bonds to us upon redemption. The estimated annual sinking fund requirements disclosed below are calculated using U.S. treasury bond pricing as of December 31, 2004. Additionally, the table reflects the redemption of certain debentures callable by us utilizing certain proceeds from the initial public offering to retire the related debentures.

| Contractual Obligations As of December 31, 2004 | Total | Less Than 1 Year | 1−3 Years | 3−5 Years | More Than 5 Years |
|---|---|---|---|---|---|
| | Payments Due by period | | | | |
| Debentures — net of sinking fund requirements | $ 33,589,598 | $ 15,896,035 | $ 2,429,675 | $ 1,113,745 | $ 14,150,143 |
| Debenture sinking fund requirements | 12,887,102 | 1,420,035 | 3,110,844 | 3,374,076 | 4,982,147 |
| Leases | 510,479 | 160,186 | 311,372 | 38,921 | — |
| Total | $ 46,987,179 | $ 17,476,256 | $ 5,851,891 | $ 4,526,742 | $ 19,132,290 |

The contractual obligation schedule above does not reflect $23.6 million principal amount of zero coupon U.S. treasury bonds held by us in escrow to secure the repayment of the debentures upon maturity. Such U.S. treasury bonds had a fair market value of $17.0 million at December 31, 2004.

**Off−Balance Sheet Arrangements**

Under the terms of our drilling programs formed from 1998 to 2001, investors have the right to tender their interest back to the drilling program and other program investors during the period from seven to 25 years after the date of the partnership's formation. To the extent that an investor tenders a drilling program interest for sale and the drilling program and other investors elect not to repurchase the withdrawing partner's interest, we will be required to repurchase the interest from the investor. The price of our repurchase is fixed by the drilling program agreement to be the lower of the PV−10 value of the assets of the program and a formula based on the amount of the investor's cash investment reduced by the amount of any cash distributions received. As of December 31, 2004, based on the December 31, 2004 reserve reports of the respective drilling programs, the aggregate PV−10 value of the assets in these programs is $19.0 million. Because this PV−10 value is less than the formula price of $94.4 million at December 31, 2004, the maximum repurchase price obligation at December 31, 2004 was $19.0 million. This PV−10 value would be higher if current prices for crude oil and natural gas were to increase when we drill the remaining 9 net wells or place the remaining 35 net wells on production on behalf of these seven drilling programs. In the event of repurchase, we receive the investor's interest in the program, which includes the investor's beneficial share of the program's reserves and related future net cash flows.

The table below presents the projected timing of our maximum potential repurchase commitment associated with these programs as of December 31, 2004:

| | Less Than 1 Year | 1−3 Years | 3−5 Years | More Than 5 Years | Total |
|---|---|---|---|---|---|
| | Amount of Repurchase Commitment per Period | | | | |
| | | | (In thousands) | | |
| Maximum potential repurchase commitment(1) | — | $ 5,569 | $ 13,130 | $ 343 | $ 19,042 |

(1) Based on the partnership reserves taken from the Williamson partnership reserve report as of December 31, 2004 and using pricing at that date. This report does not include reserves for 9 net wells that are schedules to be drilled for these programs by the fourth quarter of 2005 or for the 35 net wells drilled and waiting to be placed on production.

***Additional Repurchase Commitments***

Under the terms of 13 of our drilling programs formed before 1998, the minority interest investors have the right to require us to repurchase their interests in each program for a formula price, to the extent that the drilling programs and other program investors elect not to purchase a withdrawing partner's interest. This right is effective either seven years from the date of a partnership's formation, or between the 15th and 25th anniversary of its formation. The formula price is computed as the original capital contribution of the investor reduced by the greater of cash distributions we made to the investor, or 10% for every $1.00 which the oil price at the repurchase date is below $13.00 per barrel adjusted by the CPI changes since the program's formation. If we purchase interests in drilling programs, we receive the investor's interest in the program, which includes the investor's beneficial share of the reserves and related future net cash flows. The table below presents the repurchase commitment associated with the pre−1998 drilling programs, giving no effect to any reserve value that is acquired in repurchase.

| | Amount of Repurchase Commitment per Period | | | | |
|---|---|---|---|---|---|
| **Other Commitments As of December 31, 2004** | **Less Than 1 Year** | **1−3 Years** | **4−5 Years** | **More Than 5 Years** | **Total** |
| | ?(in thousands) | | | | |
| Partnership repurchase commitments: | | | | | |
| Pre−1998 Partnerships | $ 3,417 | — | — | $ 939 | $ 4,356 |

## Item 7A: *Quantitative and Qualitative Disclosures About Market Risk*

***Commodity Risk***

Our major market risk exposure is the commodity pricing applicable to our natural gas and oil production. Realized commodity prices received for our production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of price volatility are expected to continue.

***Interest Rate Risk***

We hold investments in U.S. treasury bonds available for sale, which represents securities held in escrow accounts on behalf of the drilling programs and purchasers of certain debentures. Additionally, we hold U.S. treasury bonds trading securities, which predominantly represent U.S. treasury bonds released from escrow accounts. The fair market value of these securities will generally increase if the federal discount rate decreases and decrease if the federal discount rate increases. All of our convertible debt has fixed interest rates, so consequently we are not exposed to cash flow or fair value risk from market interest rate changes on this debt.

***Financial Instruments***

Our financial instruments consist of cash and cash equivalents, U.S. treasury bonds, accounts receivable and other long−term liabilities. The carrying amounts of cash and cash equivalents, U.S. treasury bonds, accounts receivables and accounts payable approximate fair market value due to the highly liquid nature of these short−term instruments.

***Inflation and Changes in Prices***

The general level of inflation affects our costs. Salaries and other general and administrative expenses are impacted by inflationary trends and the supply and demand of qualified professionals and professional services. Inflation and price fluctuations affect the costs associated with exploring for and producing natural gas and oil, which have a material impact on our financial performance.

## RISK FACTORS

*You should be aware that the occurrence of any of the events described in this Risk Factors section and elsewhere in this annual report or in any other of our filings with the Securities and Exchange Commission ("SEC") could have a material adverse effect on our business, financial position, liquidity and results of operations. In evaluating us, you should consider carefully, among other things, the factors and the specific risks set forth below, and in documents we incorporate by reference. This annual report contains forward−looking statements that involve risks and uncertainties. Some of the following risks relate principally to the industry in which we operate and to our business. Other risks relate principally to the securities markets and ownership of our common shares. 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 price of your shares could decline, and you may lose all or part of your investment.*

### Risks Relating to Our Business

***Our reserve estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations or inaccurate.***

This annual report contains estimates of our proved natural gas and oil reserves and the estimated future net revenues from these reserves. These estimates are based upon various assumptions, including assumptions relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, ownership and title, taxes and the availability of funds. The process of estimating natural gas and oil reserves is complex. It requires interpretations of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. Further, the potential for future reserve revisions, either upward or downward, is significantly greater than normal because most of our reserves are undeveloped.

Actual natural gas and oil prices, future production, revenues, operating expenses, taxes, development expenditures and quantities of recoverable natural gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of future net revenues set forth in this prospectus. A reduction in natural gas and oil prices, for example, would reduce the value of proved reserves and reduce the amount of natural gas and oil that could be economically produced, thereby reducing the quantity of reserves. We may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2004, approximately 90% of our estimated net proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. We have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards. However, the estimated costs may not be accurate, development may not occur as scheduled, or the actual results may not be as estimated. We may not have or be able to obtain the capital we need to develop these proved reserves.

You should not assume that the present value of future net revenues referred to in this annual report is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any change in consumption by natural gas and oil purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of our natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor, nor does it reflect discount factors used in the marketplace for the purchase and sale of oil and gas properties. Conditions in the oil and gas industry and oil and gas prices will affect whether the 10% discount factor accurately reflects the market value of our estimated reserves.

***Failure to obtain financing and environmental approvals for the development of our Washakie Basin properties in which we own interests could have a material adverse effect on our business, financial condition or results of operations.***

Our future growth plans rely heavily on establishing significant production and reserves in the Washakie Basin. However, an inability to provide or obtain financing at acceptable rates could prevent us from developing the Washakie Basin. Furthermore, environmental restrictions in this area could prevent us from developing this acreage as planned. The U.S. Bureau of Land Management, or BLM, has begun preparation of an environmental impact statement, or EIS, which involves a series of scientific studies, surveys and public hearings and formulation of a plan for drilling and production in the Washakie Basin that will, without limitation, establish the number of wells that may be drilled in the Atlantic Rim and the timing and location of those wells. The EIS is currently expected to be completed by the end of 2005, although this projected completion date may be extended. Our prior drilling in this basin, along with our projected drilling through 2005, is being conducted under an interim drilling policy of the BLM, under which up to a total of 200 wells can be drilled in this basin, 165 of which have been allocated to us and our drilling partners. If public opposition to continued drilling in this basin or other regulatory complications occur, the EIS may not be completed during 2005, or could cause the BLM to condition, severely restrict or prohibit drilling on a more permanent basis. Legal challenges to the EIS could also materially affect the timing and ultimate environmental restrictions that are imposed on our drilling and production operations. Any or all of these contingencies could delay or halt our drilling activities or the construction of ancillary facilities necessary for production, which would prevent us from developing our property interests in the Washakie Basin as planned. We cannot predict the timing or outcome of the EIS. Conditions, delays or restrictions imposed on the drilling or the management of groundwater produced during drilling could severely limit our operations there or make them uneconomic. Any unfavorable developments in the Washakie Basin could impede our growth, as we intend to undertake significant activity in order to increase our production and reserves in this area.

***Our substantial contingent obligations to repurchase 10% of our outstanding bonds and debentures annually and to repurchase drilling program interests could strain our financial resources.***

As of December 31, 2004, we had $46.5 million of outstanding bonds and debentures. On January 12, 2005 and January 13, 2005, we called for redemption on March 31, 2005 all of the 2007 bonds and 2017 sinking fund convertible debentures, with outstanding balances at December 31, 2004, of $9.0 million and $5.0 million respectively. Holders of our remaining bonds and debentures are entitled each year to tender up to 10% of the original aggregate face amount of each series of debentures for repurchase by us at their face amount, or $3.3 million in 2005 and $2.9 million in 2006, adjusted for the 2007 and 2017 called bonds.

In addition, under the terms of 13 of our drilling programs formed before 1998, to the extent that the drilling programs and other program investors elect not to purchase a withdrawing partner’s interest, the minority interest investors have the right to require us to repurchase their interests in each program for a formula price. This right is effective either seven years from the date of a partnership’s formation, or between the 15th and 25th anniversary of their formation. As of December 31, 2004, we have potential repurchase obligations for programs which mature on January 1, 2005 thru June 30, 2005, of approximately $3.4 million and for programs which mature on and after December 2009 of approximately $0.9 million. At December 31, 2004, a portion of our repurchase obligation was secured by $1.1 million market value of U.S. treasury bonds held by an independent trustee.

Depending upon the amount of cash distributions to investors in our programs prior to the repurchase obligation dates and the number of investors who tender their interests for repurchase as their tender rights become available, a significant amount of funds may be required for these repurchases. These repurchase obligations could put a strain upon our financial resources and otherwise adversely affect our ability to execute our business plan. Any payment made under this obligation would be recorded as a reduction to minority interest as shown on our balance sheet.

Under the terms of our seven drilling programs formed between 1998 and 2001 investors have the right to require us to repurchase their interests in each program seven to 25 years from the date of a partnership’s formation, to the extent that the drilling programs and other program investors elect not to purchase the investor's interest. The price of our repurchase is fixed by the drilling program agreement to be the lower of the PV−10 value of the assets of the program and a formula based on the amount of the investor's cash investment reduced by the amount of any cash distributions received. As of December 31, 2004, based on the December 31, 2004 reserve reports of the respective drilling programs, the aggregate PV−10 value of the assets in these programs was $19.0 million. Because this amount is less than the formula price of $94.4 million as of December 31, 2004, the PV−10 of $19.0 million is our maximum repurchase obligation as of December 31, 2004. This PV−10 amount may increase when we drill the remaining 9 net wells or place the remaining 35 net wells on production on behalf of these seven drilling programs.

Based on the formula price as of December 31, 2004, if in the future the drilling program PV−10 value were to exceed $94.4 million, then our maximum obligation would be the formula price of $94.4 million, consisting of obligations of $42.6 million between January 1, 2005 and December 31, 2008, $50.5 million between January 1, 2009 and December 31, 2010 and $1.3 million thereafter.

***We face significantly increasing water disposal costs in our CBM drilling operations.***

The Wyoming Department of Environmental Quality, or Wyoming DEQ, has restrictive regulations applying to the surface disposal of water produced from our CBM drilling operations. We typically obtain Clean Water Act, Safe Drinking Water Act and analogous state and local permits to use surface discharge methods, such as settling ponds, to dispose of water when the groundwater produced from the coal seams will not exceed surface discharge permit limitations. Surface disposal options have volumetric limitations and require an extensive third−party water sampling and laboratory analysis program to ensure compliance with state permit standards. Alternative methods to surface disposal of water are more expensive. These alternatives include installing and operating treatment facilities or drilling disposal wells to re−inject the produced water into the underground rock formations adjacent to the coal seams or lower sandstone horizons. Injection wells are regulated by the Wyoming DEQ and the Wyoming Oil & Gas Conservation Commission, and permits to drill these wells are obtained from these agencies. Based on our experience with CBM production in the Powder River Basin, we believe that permits for surface discharge of produced water in that basin, as well as the Washakie Basin, will become more difficult to obtain. In Wyoming, our produced water is currently injected at six wells, and we have obtained permits to drill six more of these underground injection wells. We expect the costs to dispose of produced water to increase significantly, which could have a material adverse effect on our business, financial condition and results of operations.

***Operational impediments may hinder our access to natural gas and oil markets or delay our production.***

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. This dependence is heightened in our CBM operations where this infrastructure is less developed than in our traditional oil and gas operations. For example, there is limited pipeline capacity in the southern portion of the Washakie Basin. Therefore, if drilling results are positive in the entire length of the Washakie Basin, a new pipeline would need to be built at a cost of approximately $25 million, our portion of which would be approximately $12.5 million.

We deliver natural gas and oil through gathering systems and pipelines that we do not own. These facilities may not be available to us in the future. Our ability to produce and market natural gas and oil is affected and also may be harmed by:

- the lack of pipeline transmission facilities or carrying capacity;
- federal and state regulation of natural gas and oil production; and
- federal and state transportation, tax and energy policies.

We recently entered into an agreement with Anadarko to jointly construct compression facilities and a pipeline in the Washakie Basin. Any significant change in our arrangement with Anadarko or other market factors affecting our overall infrastructure facilities could adversely impact our ability to deliver the natural gas we produce to market in an efficient manner, or its price. In some cases, we may be required to shut−in wells, at least temporarily, for lack of a market or because of the inadequacy or unavailability of transportation facilities. If that were to occur, we would be unable to realize revenue from those wells until arrangements were made to deliver our production to market.

***Our level of indebtedness reduces our financial flexibility and could impede our ability to operate.***

As of December 31, 2004, our long−term debt was $50.0 million, substantially all of which consists of debentures we have issued from time to time with due dates ranging from December 31, 2007 through December 31, 2022. At December 31, 2004, the ratio of our debt to equity was 0.3 to 1.0, and the ratio of our debt to total assets was 0.2 to 1.0. We are required to make sinking fund payments on $46.5 million principal amount of our outstanding debentures, with respect to which we have deposited $23.6 million of principal amount of U.S. treasury bonds as of December 31, 2004, with estimated sinking fund payments required of $1.4 million by the end of 2005 and $1.5 million by the end of 2006. We are also contingently obligated to repurchase 10% of our outstanding bonds annually. We may not have sufficient funds to make repayments or sinking fund payments throughout all future maturities.

Our level of debt affects our operations in several important ways, including the following:

- a large portion of our net cash flow from operations has and will continue to be used to pay interest on borrowings;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- our leveraged financial position may make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures.

***We may incur additional debt in order to fund our exploration and development activities, which would continue to reduce our financial flexibility and could have a material adverse effect on our business, financial condition or results of operations.***

We may incur additional debt in order to make future acquisitions or develop our properties. A higher level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. We may not be able to generate sufficient cash flow to pay the interest on our debt or pay our debt at maturity. In addition, if we are unable to repay our debt at maturity out of cash on hand, we could attempt to refinance the debt or repay the debt with the proceeds of an equity offering. We may be unable to sell public debt or equity securities or do so on acceptable terms to pay or refinance the debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions and our market value and operations performance at the time of the offering or other financing. 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.

***We have substantial capital requirements that, if not met, may hinder our growth and operations.***

Our future growth depends on our ability to make large capital expenditures for the exploration and development of our natural gas and oil properties and to acquire additional properties. We have projected these capital expenditures to be approximately $37.6 million in 2005. Historically, we have financed our capital expenditures primarily through drilling programs that participated in the exploration, drilling and development of the projects, and to a lesser extent through debt and equity financing. In the future, we intend to finance these capital expenditures through the proceeds from our initial public offering and from cash flow from operations or a combination of these methods. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the success of our CBM projects in the Washakie Basin;
- our success in locating and producing new reserves;

- the level of production from existing wells; and
- prices of natural gas and oil.

Additional financing sources may be required in the future to fund our developmental and exploratory drilling. Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. Additional debt financing could lead to:

- a substantial portion of our operating cash flow being dedicated to the payment of principal and interest;
- our being more vulnerable to competitive pressures and economic downturns; and
- restrictions on our operations.

Financing may not be available in the future under existing or new financing arrangements, or we may not be able to obtain necessary financing on acceptable terms, if at all. If sufficient capital resources are not available, we may be forced to curtail our drilling, acquisition and other activities or be forced to sell some of our assets on an untimely or unfavorable basis, which would have an adverse affect on our business, financial condition and results of operations.

***We have incurred losses from operations in the past and cannot guarantee profitability in the future.***

At December 31, 2004, we had an accumulated deficit of $77.7 million and total stockholders' equity of $157.6 million. We have recognized annual net losses in each year since 2000. See "Selected Consolidated Financial Data". We may not achieve or sustain profitability or positive cash flows from operating activities in the future.

***Properties that we buy may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.***

One of our growth strategies is to pursue selective acquisitions of natural gas and oil reserves. We perform a review of the target properties that we believe is consistent with industry practices. However, these reviews are inherently incomplete. It generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, a seller may be unwilling or unable to provide effective contractual protection against all or part of those problems, and we often assume environmental and other risks and liabilities in connection with the acquired properties.

***Our operations in Wyoming could be adversely affected by abnormally poor weather conditions.***

Our operations in Wyoming are conducted in areas subject to extreme weather conditions and often in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions. Unusually severe weather could further curtail these operations, including drilling of new wells or production from existing wells, and depending on the severity of the weather, could have a material adverse effect on our business, financial condition and results of operations.

***As general partner of limited partnerships and co−venturer in joint ventures, we are liable for various obligations of those partnerships and joint ventures.***

We currently serve as the managing general partner of nine limited partnerships and participate in four joint ventures as a result of our sponsorship of drilling programs. As general partner or co−venturer, we are contingently liable for the obligations of the partnerships or joint ventures, as applicable, including responsibility for their day−to−day operations and liabilities which cannot be repaid from partnership or venture assets, insurance proceeds or indemnification by others. In the future, we might be exposed to litigation in connection with partnership or joint venture activities or find it necessary to advance funds on behalf of certain partnerships or joint ventures to protect the value of the natural gas and oil properties by drilling wells to produce undeveloped reserves or to pay lease operating expenses in excess of production. These activities may have a material adverse effect on our business, financial condition and results of operations. See "Business and Properties — Drilling Programs".

***Our role as general partner of limited partnerships and co−venturer in joint ventures may result in conflicts of interest, which may not be resolved in our best interests or the best interests of our stockholders.***

Our role as general partner of limited partnerships and co−venturer in joint ventures may result in conflicts of interest between the interests of those entities and our stockholders. For example, we plan to continue drilling natural gas and oil wells for the various drilling programs we have sponsored. The allocation of those wells to the drilling programs may give rise to a conflict of interest between our interests and the interests of the partners or co−venturers in our drilling programs. Any resolution of these conflicts may not always be in our best interests.

***The loss of our chief executive officer or other key management and technical personnel or our inability to attract and retain experienced technical personnel could adversely affect our ability to operate.***

We depend to a large extent on the efforts and continued employment of Norman F. Swanton, our chief executive officer and chairman, Timothy A. Larkin, our executive vice president and chief financial officer, and Kenneth A. Gobble, our senior vice president of exploration and production, and other key management and technical personnel. The loss of the services of Messrs. Swanton, Larkin, Gobble or other key management and technical personnel could adversely affect our business operations. We maintain key person life insurance on Messrs. Swanton, Larkin and Gobble but not on other key management and technical personnel.

The success of our development, exploration and production activities depends, in part, on our ability to attract and retain experienced petroleum engineers, geologists and other key personnel. From time to time, competition for experienced engineers and geologists is intense. If we cannot retain these personnel or attract additional experienced personnel, our ability to compete in the geographic regions in which we conduct our operations could be harmed.

***We do not insure against all potential operating risks. We may incur substantial losses and be subject to substantial liability claims as a result of our natural gas and oil operations.***

We are not insured against all risks. We ordinarily maintain insurance against various losses and liabilities arising from our operations in accordance with customary industry practices and in amounts that management believe to be prudent. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations. Our natural gas and oil exploration and production activities are subject to hazards and risks associated with drilling for, producing and transporting natural gas and oil, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of natural gas, oil, 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;

• regulatory investigations and penalties; and

• natural disasters.

Any of these risks could have a material adverse effect on our ability to conduct operations or result in substantial losses to us. 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, it could have a material adverse effect on our business, financial condition and results of operations. See "Business and Properties — Operating Hazards And Insurance".

***We have limited control over activities on properties we do not operate, which could reduce our production and revenues.***

Substantially all of our business activities are conducted through joint operating agreements under which we own partial interests in natural gas and oil properties. We do not operate all of the properties in which we have an interest and in many cases we do not have the ability to remove the operator in the event of poor performance. As a result, we have a limited ability to exercise influence over normal operating procedures, expenditures or future development of underlying properties and their associated costs. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our revenues and production. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our and the operator's control, including:

• timing and amount of capital expenditures;

• expertise and financial resources;

• inclusion of other participants in drilling wells; and

• use of technology.

***Defects in the title to any of our natural gas and oil interests could result in the loss of some of our natural gas and oil properties or portions thereof or liability for losses resulting from defects in the assignment of leasehold rights.***

We obtain interests in natural gas and oil properties with varying degrees of warranty of title such as general, special, quitclaim or without any warranty. We acquired approximately one−half our interest in the Wilmington unit from Magness Petroleum in 1999 and the remainder of our interest in January of 2005 in connection with the closing of our purchase and sale transaction with Magness Petroleum. Magness Petroleum had acquired its interests from a third party that in turn had acquired its interest from Exxon Corporation with no warranty of title. Exxon had owned the Wilmington unit for over 25 years before its sale in 1997. We have acquired no title opinion as to the interests we own in that field, which may ultimately prove to be less than the interests we believe we own. Losses in this field may result from title defects or from ownership of a lesser interest than we assume we acquired or from the assignment of leasehold rights by us to our drilling programs. In other instances, title opinions may not be obtained if in our discretion it would be uneconomical or impractical to do so. This increases the possible risk of loss and could result in total loss of properties purchased. Furthermore, in certain instances we may determine to purchase properties even though certain technical title defects exist if we believe it to be an acceptable risk under the circumstances.

**Risks Relating to the Oil and Gas Industry**

***A substantial or extended decline in natural gas and oil prices may adversely affect our ability to meet our capital expenditure obligations and financial commitments.***

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, natural gas and oil. Declines in the prices of, or demand for, natural gas and oil may adversely affect our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations. Lower natural gas and oil prices may also reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices have been volatile, and they are likely to continue to be volatile in the future. A decrease in natural gas or oil prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment of the value of these assets. If natural gas or oil prices decline significantly for extended periods of time in the future, we might not be able to generate enough cash flow from operations to meet our obligations and make planned capital expenditures. Natural gas and oil prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control.

Among the factors that cause this fluctuation are:

- changes in domestic and global supply and demand for natural gas and oil;
- levels of production and other activities of the Organization of Petroleum Exporting Countries and other natural gas and oil producing nations;
- market expectations about future prices;
- the level of global natural gas and oil exploration, production activity and inventories;
- political conditions, including embargoes, in or affecting other oil producing activity; and
- the price and availability of alternative fuels.

Lower natural gas and oil prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of natural gas and oil we can produce economically. A substantial or extended decline in natural gas and oil prices may have a material adverse effect on our business, financial condition and results of operations.

***Drilling for and producing natural gas and oil are high risk activities with many uncertainties that could have a material adverse effect on our business, financial condition or results of operations.***

Our future success depends largely on the success of our exploitation, exploration, development and production activities. These activities are subject to numerous risks beyond our control, including the risk that we will not find any commercially productive natural gas or oil reservoirs. 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. See "— Risks Related to Our Business — Our reserve estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations or inaccurate" 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 prevent drilling operations, including:

- unexpected drilling conditions;
- pressure or irregularities in geological formations;
- equipment failures or accidents;
- well blow−outs;
- fires and explosions;
- pipeline and processing interruptions or unavailability;
- title problems;
- adverse weather conditions;

- lack of market demand for natural gas and oil;
- delays imposed by or resulting from compliance with environmental and other regulatory requirements;
- shortages of or delays in the availability of drilling rigs and the delivery of equipment; and
- reductions in natural gas and oil prices.

Our future drilling activities may not be successful. Our drilling success rate overall and within a particular area could decline. We could incur losses by drilling unproductive wells. Also, we may not be able to obtain any contracts covering our lease rights in potential drilling locations. We cannot be sure that we will ever drill our identified potential drilling locations or that we will produce natural gas or oil from them or from any other potential drilling locations. Shut−in wells, curtailed production and other production interruptions may negatively impact our business and result in decreased revenues.

***If natural gas and oil prices decrease, we may be required to record an impairment, which would reduce our stockholders' equity.***

We use the successful efforts method of accounting for costs related to our natural gas and oil properties. Accordingly, we capitalize the cost to acquire, explore for and develop gas and oil properties. Wells are evaluated on a field−by−field basis for impairment. We review our natural gas and oil properties on a field level when circumstances indicate that the capitalized costs, less accumulated depreciation, depletion and amortization or the carrying value of the property, may not be recoverable. If the carrying value of the property exceeds the expected future undiscounted cash flows, an amount equal to the excess of the carrying value over the fair value of the property, generally based upon discounted cash flow, is charged to expense. An impairment results in a non−cash charge to earnings which does not impact cash flow from operating activities, but does reduce our stockholders' equity. The risk that we will be required to write down the carrying value of our oil and gas properties increases when oil and gas prices are low or volatile. In addition, write−downs may occur if we experience substantial downward adjustments to our estimated proved reserves. Once incurred, a write−down of oil and gas properties is not reversible at a later date. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies" for additional information on these matters.

***Competition in the oil and gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do, which may adversely affect our ability to compete.***

We operate in the highly competitive areas of oil and gas exploration, development and acquisition with a substantial number of other companies. We face intense competition from independent, technology−driven companies as well as from both major and other independent oil and gas companies in each of the following areas:

- acquiring desirable producing properties or new leases for future exploration;
- marketing our natural gas and oil production;
- integrating new technologies; and
- acquiring the equipment and expertise necessary to develop and operate our properties.

Many of our competitors have financial, managerial, technological and other resources substantially greater than ours. These companies may be able to pay more for exploratory prospects and productive oil and gas properties, and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. To the extent our competitors are able to pay more for properties than we are, we will be at a competitive disadvantage. Further, many of our competitors may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties, and consummate transactions in this highly competitive environment.

***We are subject to complex laws and regulations, including environmental regulations, that can have a material adverse effect on the cost, manner or feasibility of doing business.***

Exploration for and the production and sale of oil and gas in the United States is subject to extensive federal, state and local laws and regulations, including complex tax and environmental laws and regulations, and requires various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. Alternatively, failure to comply with these laws and regulations, including the requirements of any permits, may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Compliance costs are significant. Further, these laws and regulations, particularly in the Rocky Mountain region, could change in ways that substantially increase our costs and associated liabilities. We cannot be certain that existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations will not harm our business, results of operations and financial condition. For example, matters subject to regulation and the types of permits required include:

• water discharge and disposal permits for drilling operations;

• drilling permits;

• drilling bonds;

• reclamation;

• spacing of wells;

• occupational safety and health;

• unitization and pooling of properties;

• air quality, noise levels and related permits;

• rights−of−way and easements;

• reports concerning operations to regulatory authorities;

• calculation and payment of royalties;

• gathering, transportation and marketing of gas and oil;

• taxation; and

• waste disposal.

Under these laws and regulations, we could be liable for:

• personal injuries;

• property damage;

• oil spills;

• discharge of hazardous materials;

• well reclamation costs;

• surface remediation and clean−up costs;

• fines and penalties;

• natural resource damages; and

• other environmental protection and damages issues.

See “Business and Properties — Regulations” for a more detailed discussion of laws affecting our operations.

***Shortages of rigs, equipment, supplies and personnel could delay or otherwise adversely affect our cost of operations or our ability to operate according to our business plans.***

If domestic drilling activity increases, particularly in the fields in which we operate, a general shortage of drilling and completion rigs, field equipment and qualified personnel could develop. As a result, the costs and delivery times of rigs, equipment and personnel could be substantially greater than in previous years. From time to time, including the present, these costs have sharply increased and could do so again. For example, in the second half of 2004, as energy prices increased significantly, we experienced higher costs for drilling rigs, equipment and personnel. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increasing number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail our exploration and development operations, which could in turn harm our operating results.

***Unless we replace, maintain or expand our natural gas and oil reserves, our reserves and production will decline, which could have a material adverse effect on our business, financial condition and results of operations.***

In general, production from natural gas and oil properties declines over time as reserves are depleted, with the rate of decline depending on reservoir characteristics. If we are not successful in our exploitation, exploration, development and enhancement activities, or in acquiring properties containing proved reserves, our proved reserves will decline as reserves are produced. Our future natural gas and oil production is highly dependent upon our ability to economically find, develop or acquire reserves in commercial quantities.

To the extent cash flow from operations is reduced, either by a decrease in prevailing prices for natural gas and oil or an increase in finding and development costs, and external sources of capital become limited or unavailable, our ability to make the necessary capital investment to maintain or expand our asset base of natural gas and oil reserves would be impaired. Even with sufficient available capital, our future exploration and development activities may not result in additional proved reserves, and we may not be able to drill productive wells at acceptable costs.

**Risks Relating to Ownership of Our Common Stock**

***The number of shares eligible for future sale or which have registration rights could adversely affect the future market for our common stock.***

Sales of substantial amounts of our common stock in our public market, or the perception that a large number of shares are available for sale, could depress the market price of our common stock. We have 34,619,204 shares of common stock are outstanding, 11,419,281 shares of common stock are issuable upon conversion of our convertible debt and convertible preferred stock and 6,461,637 shares of common stock are issuable upon exercise of outstanding options and warrants. In addition to the shares of common stock sold in our initial public offering, approximately 13,640,145 shares of our common stock are immediately eligible for sale in the public market. An additional 4,179,059 shares held by our affiliates are immediately eligible for sale in the public market subject to the volume and other limitations of Rule 144. Further, upon conversion by the holders of existing convertible debt and preferred stock into common stock, 11,419,281 shares will immediately be eligible for sale in the public market, and 3,331,549 shares held by our affiliates will immediately be eligible for sale subject to the volume and other limitations of Rule 144. In addition, as soon as practicable following the date of this annual report, we intend to file a registration statement on Form S−8 under the Securities Act to register up to 6,745,194 shares of our common stock reserved for grant or previously granted under our stock option plans. These shares generally will be available for sale in the public market by holders who are not our affiliates and, subject to the volume and other applicable limitations of Rule 144, by holders who are our affiliates, subject to vesting restrictions. Further, upon conversion by holders of outstanding warrants to purchase shares of our common stock, an aggregate of 3,161,681 shares will be eligible for sale in the public market upon our registration of the underlying shares by June 4, 2005.

All of our directors, executive officers and certain of our stockholders, holding approximately 17.5% shares of our common stock, are subject to agreements with our initial public offering underwriters or us that restrict their ability to sell or transfer their stock for 180 days from December 16, 2004. After these agreements expire, such shares will be eligible for sale in the public market.

In accordance with the terms and conditions of the registration rights agreement dated December 12, 2002, holders of at lease 50% of our 6,560,809 shares of convertible preferred stock as of December 31, 2004 have a one−time right to demand that their shares of common stock issuable upon conversion of the convertible preferred stock be registered under the Securities Act commencing June 14, 2005. Also, commencing June 14, 2005, these holders may have the right to include their shares of common stock, subject to the consent of any underwriter, in registration statements that we may file, if any, to register shares of our common stock under the Securities Act for ourselves or other stockholders. Additionally, commencing April 3, 2005, we are required to file a registration statement for 2,875,000 shares of outstanding common stock and 1,437,500 shares of common stock issuable upon exercise of our class A and class B warrants under the Securities Act. We are also required commencing June 6, 2005 to file a registration statement for 3,000,000 shares of outstanding common stock and 1,500,000 shares of common stock issuable upon exercise of our class A and class B warrants under the Securities Act. The holders of these securities have agreed to certain restrictions on the transfer of their stock for a period ending June 14, 2005. If our stockholders sell significant amounts of common stock in any public market that develops or exercise their registration rights and sell a large number of shares, the price of our common stock could be negatively affected. If we were to include shares held by those holders in a registration statement pursuant to the exercise of their registration rights, those sales could impair our ability to raise needed capital by depressing the price at which we could sell our common stock or impede such an offering altogether.

***Our stock price may be volatile, and your investment in our stock could decline in value.***

In recent years, the stock market has experienced significant price and volume fluctuations. Our common stock may also experience volatility unrelated to our own operating performance for reasons that include:

- domestic and worldwide supplies and prices of and demand for natural gas and oil;
- political conditions in natural gas and oil producing regions;
- war and acts of terrorism;
- demand for our common stock;
- revenue and operating results failing to meet the expectations of securities analysts or investors in any particular quarter;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- investor perception of our industry or our prospects;
- general economic trends;
- limited trading volume of our stock;
- changes in environmental and other governmental regulations;
- actual or anticipated quarterly variations in our operating results;
- our involvement in litigation;
- conditions generally affecting the oil and natural gas industry;
- the prices of oil and natural gas;
- announcements relating to our business or the business of our competitors;
- our liquidity; and
- our ability to obtain or raise additional funds.

***Control by our executive officers and directors will limit your ability to influence the outcome of matters requiring stockholder approval and could discourage our potential acquisition by third parties.***

As of March 15, 2005, our executive officers and directors beneficially owned approximately 17.6% of our common stock. These stockholders, if acting together, would be able to influence significantly all matters requiring approval by our stockholders, including the election of our board of directors and the approval of mergers or other business combination transactions. This concentration of ownership could have the effect of delaying or preventing a change in our control or otherwise discourage a potential acquirer from attempting to obtain control of us, which in turn could have an adverse effect on the market price of our common stock or prevent our stockholders from realizing a premium over the market price for their shares of our common stock.

***Provisions in our articles of incorporation, bylaws and Maryland law may make it more difficult to effect a change in control, which could adversely affect the price of our common stock.***

Provisions of our articles of incorporation, bylaws and Maryland law could make it more difficult for a third party to acquire us, even if doing so would be beneficial to our stockholders. We may issue shares of preferred stock in the future without stockholder approval and upon such terms as our board of directors may determine. Our issuance of this preferred stock could have the effect of making it more difficult for a third party to acquire, or of discouraging a third party from acquiring, a majority of our outstanding stock and potentially prevent the payment of a premium to stockholders in an acquisition.

Our articles of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us or our management. These provisions include:

- giving the board the exclusive right to fill all board vacancies;
- providing that special meetings of stockholders may only be called by the board pursuant to a resolution adopted by
  - —a majority of the board, either upon a motion or upon written request by holders of at least 66 2/3% of the voting power of the shares entitled to vote, or
  - —by our president;
- a classified board of directors;
- permitting removal of directors only for cause and with a super−majority vote of the stockholders; and
- prohibiting cumulative voting in the election of directors.

These provisions also could discourage proxy contests and make it more difficult for our stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, and may limit the price that investors are willing to pay in the future for shares of our common stock.

We are also subject to provisions of the Maryland General Corporation Law that prohibit business combinations with persons owning 10% or more of the voting shares of a corporation’s outstanding stock, unless the combination is approved by the board of directors prior to the person owning 10% or more of the stock, for a period of five years, after which the business combination would be subject to special stockholder approval requirements. This provision could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company, or may otherwise discourage a potential acquirer from attempting to obtain control from us, which in turn could have a material adverse effect on the market price of our common stock. See “Description of Capital Stock”.

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

Under the terms of our convertible preferred stock, we may not pay dividends on our common stock unless all accrued dividends on our convertible preferred stock have been paid. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends on our common stock in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial conditions, current and anticipated cash needs and plans for expansion.

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

See Report of Registered Public Accounting Firm at Item 15.

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

None.

**Item 9A:** ***Controls and Procedures***

Our Chief Executive Officer and Chief Financial Officer (Certifying Officers) performed an evaluation of the Company's disclosure controls and procedures as of the end of the period covered by this Form 10−K. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Based on this evaluation, the Certifying Officers have concluded that the Company's disclosure controls and procedures are effective. In addition, there have been no changes in our internal control over financial reporting during the quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting.

## PART III

**Item 10:** ***Directors and Executive Officers of the Registrant***

See "Executive Officers, Board of Directors, Committees of the Board and Section 16(a) Beneficial Ownership Reporting Compliance" in the Warren Resources, Inc. Proxy Statement ("Proxy Statement"), for the Annual Meeting of Stockholders of Warren Resources, Inc. to be held on June 15, 2005 (to be filed with the SEC within 120 days after the end of the Company's fiscal year ended December 31, 2004) which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (Code of Ethics) can be found on the Company's internet website located at www.warrenresources.com. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company intends to disclose the information on its internet website. This information will remain on the website for at least 12 months.

**Item 11:** ***Executive Compensation***

Information required by this item will be contained in the Proxy Statement under the caption "Executive Compensation," and is hereby incorporated by reference thereto.

**Item 12:** ***Securities Ownership of Certain Beneficial Owners and Management***

Information required by this item will be contained in the Proxy Statement under the caption “Securities Ownership of Certain Beneficial Owners and Management,” and is incorporated herein by reference.

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

Information required by this item will be contained in the Proxy Statement under the caption “Certain Transactions,” and is hereby incorporated by reference thereto.

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

Information required by this item will be contained in the Proxy Statement under the caption “Auditors’ Fees,” and is hereby incorporated by reference thereto.

**PART IV**

**Item 15:** ***Exhibits, Financial Statement Schedules***

(a)(1) Financial Statements

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(a)(2) All other schedules have been omitted because the required information is inapplicable or is shown in the Notes to the Consolidated Financial Statements.

(a)(3) Exhibits required to be filed by Item 601 of Regulation S−K.

| Exhibit No. | Description |
|---|---|
| 2.1(1) | Stock Exchange Agreement, dated September 1, 2000, by and among the Registrant, Petroleum Development Corporation, James C. Johnson, Jr. and Gregory S. Johnson. |
| 3.1† | Articles of Incorporation of Registrant filed May 20, 2004 (Maryland) |
| 3.2(10) | Bylaws of the Registrant, dated June 2, 2004 |
| 3.3(10) | Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland) |
| 3.4(10) | Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland) |
| 3.5(10) | Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland) |
| 3.6(10) | Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland) |
| 4.1† | Specimen Stock Certificate for Common Stock |
| 4.2(1) | Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated December 1, 2000 regarding 12% debentures due December 31, 2007 |

| Exhibit No. | Description |
| --- | --- |
| 4.3(1) | Form of Bond Certificate for 12% debentures due December 31, 2007 |
| 4.4(1) | Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated February 1, 1999 regarding 13.02% debentures due December 31, 2010 and December 31, 2015 |
| 4.5(1) | Form of Bond Certificate for 13.02% debentures due December 31, 2010 |
| 4.6(1) | Form of Bond Certificate for 13.02% debentures due December 31, 2015 |
| 4.7(8) | Form of Class A Common Stock Warrant |
| 4.8(8) | Form of Class B Common Stock Warrant |
| 4.9(3) | Form of Registration Rights Agreement made as of December 12, 2002, by and between Warren Resources the Investors in the Series A 8% Cumulative Convertible Preferred Stock. |
| 4.10(6) | Form of Subscription and Registration Rights Agreement dated February 3, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated January 21, 2004 |
| 4.11(10) | Form of Subscription and Registration Rights Agreement dated July 30, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated July 9, 2004 |
| 4.12(5) | Form of Contribution Agreement by and between Warren Resources, Inc., and various Delaware limited liability companies. |
| 10.1(1) | 2000 Equity Incentive Plan for Warren E&P Subsidiary |
| 10.2(1) | Amendment to 2000 Stock Incentive Plan for Warren E&P Subsidiary |
| 10.3(1) | 2001 Stock Incentive Plan |
| 10.4(1) | 2001 Key Employee Stock Incentive Plan |
| 10.5(1) | Employment Agreement dated January 1, 2001, between the Registrant and Norman F. Swanton |
| 10.6(1) | Employment Agreement dated January 1, 2001, between the Registrant and Timothy A. Larkin |
| 10.7(9) | Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Norman F. Swanton |
| 10.8(9) | Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin |
| 10.9(9) | Employment Agreement dated March 1, 2004, between the Registrant and Lloyd Davies |
| 10.10(9) | Employment Agreement dated January 1, 2004, between the Registrant and David E. Fleming |
| 10.11(10) | Employment Agreement dated January 1, 2004, between the Registrant and Ellis G. Vickers |
| 10.12(1) | Form of Indemnification Agreement |
| 10.13(1) | Joint Venture Agreement dated May 24, 1999, by and between Warren Resources of California, Inc., Warren Development Corp., Warren E&P and Magness Petroleum Company |
| 10.15(1) | Gas Purchase Agreement dated January 28, 2000, by and between Western Gas Resources, Inc. and Big Basin Petroleum, LLC |
| 10.16(1) | December 20, 2000 Letter of Agreement to Amend the Gas Purchase Contract dated January 28, 2000, between Western Gas Resources Inc. and Petroleum Development Corp., as successor in interest to Big |

| | |
|---|---|
| | Basin Petroleum, LLC |
| 10.17(1) | Gas Purchase and Sales Contract dated April 1, 2000, between the Registrant and Tenaska Marketing Ventures |
| 10.18(1) | Form of Partnership Production Marketing Agreement |
| 10.19(4) | Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc. |
| 10.20(4) | Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp. |

| Exhibit No. | Description |
|---|---|
| 10.21(4) | Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc. |
| 10.22(11) | Purchase and Sale Agreement dated November 24, 2004 by and among Warren Resources of California, Inc., Magness Petroleum Company and Next Generation Investments, LLC. |
| 10.23(11) | Settlement Agreement and Release dated November 24, 2004 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc., Warren Development Corp. and Magness Petroleum Company. |
| 11† | Statements regarding Computation of Per Share Earnings (Included in the Financial Statement in Part 4) |
| 14(7) | Code of Ethics for Senior Financial Officers |
| 21.1(12) | Subsidiaries of the Registrant |
| 23.1† | Consent of Williamson Petroleum Consultants, Inc. |
| 23.2† | Consent of CBIZ Valuation Group, LLC |
| 31.1† | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 |
| 31.2† | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002. |
| 32† | Section 1350 Certification |

(1) Incorporated by reference to the Company's Registration Statement on Form 10, Commission File No. 000−33275, filed on October 26, 2001.

(2) Incorporated by reference to the Company's Amendment No. 1 to Registration Statement on Form 10/A, Commission File No. 000−33275, filed on March 6, 2002.

(3) Incorporated by reference to the Company's Current Report on Form 8−K filed on December 12, 2002.

(4) Incorporated by reference to the Company's Current Report on Form 8−K filed on December 24, 2002.

(5) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2003.

(6) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed on February 11, 2004.

(7) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2002, filed on March 31, 2003.

(8) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2003, filed on March 15, 2004.

(9) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended March 31, 2004, filed May 12, 2004.

(10) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2004, filed on August 13, 2003.

(11) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed November 30, 2004.

(12) Incorporated by reference to the Company's Registration Statement on From S−1/ A, Commission File No. 333−118535, filed December 2, 2004.

† Filed herewith.

## SIGNATURES

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

**WARREN RESOURCES, INC.**

| | |
|---|---|
| By | /s/ Norman F. Swanton<br>Norman F. Swanton<br>President, Chief Executive Officer,<br>Director and Chairman |
| By | /s/ Timothy A. Larkin<br>Timothy A. Larkin<br>Executive Vice President,<br>Chief Financial Officer, and<br>Principal Accounting Officer |

Dated: March 15, 2005

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

| Signature | Title (Principal Function) | Date |
|---|---|---|
| /s/ Norman F. Swanton<br>Norman F. Swanton | President, Chief Executive Officer, Director and Chairman | March 15, 2005 |
| /s/ Timothy A. Larkin<br>Timothy A. Larkin | Executive Vice President, Chief Financial Officer and Principal Accounting Officer | March 15, 2005 |
| /s/ Anthony Coelho<br>Anthony Coelho | Director | March 15, 2005 |
| /s/ Lloyd Davies<br>Lloyd Davies | Director | March 15, 2005 |
| /s/ Dominick D’Alleva<br>Dominick D’Alleva | Director | March 15, 2005 |
| /s/ Marshall Miller<br>Marshall Miller | Director | March 15, 2005 |
| /s/ Thomas Noonan<br>Thomas Noonan | Director | March 15, 2005 |
| /s/ Michael R. Quinlan<br>Michael R. Quinlan | Director | March 15, 2005 |
| /s/ Chet Borgida<br>Chet Borgida | Director | March 15, 2005 |

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**Report of Independent Registered Public Accounting Firm**

Board of Directors
Warren Resources, Inc.

We have audited the accompanying consolidated balance sheets of Warren Resources, Inc. and Subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's intended control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Warren Resources, Inc. and Subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations as required by the provisions of Statement of Financial Accounting Standards No. 143, *Asset Retirement Obligations.*

GRANT THORNTON LLP
Oklahoma City, Oklahoma
February 18, 2005

**Warren Resources, Inc. and Subsidiaries**
**CONSOLIDATED BALANCE SHEETS**

| | December 31, 2004 | December 31, 2003 |
|---|---|---|
| **ASSETS** | | |
| Current Assets | | |
| Cash and cash equivalents | $ 99,920,885 | $ 24,528,999 |
| Accounts receivable — trade | 1,481,925 | 2,386,180 |
| Accounts receivable from affiliated partnerships | 143,297 | 389,271 |
| Trading securities | 174,247 | 201,152 |
| Restricted investments in U.S. Treasury bonds — available for sale, at fair value (amortized cost of $5,944,587 in 2004 and $1,293,411 in 2003) | 6,099,968 | 1,402,358 |
| Other current assets | 211,509 | 2,031,701 |
| Total current assets | 108,031,831 | 30,939,661 |
| Other Assets | | |
| Oil and gas properties — at cost, based on successful efforts method of accounting, net of accumulated depreciation, depletion, amortization and impairment | 116,595,306 | 94,949,545 |
| Property and equipment — at cost, net | 395,444 | 591,663 |
| Restricted investments in U.S. Treasury bonds — available for sale, at fair value (amortized cost of $10,778,899 in 2004 and $12,627,574 in 2003) | 12,062,085 | 13,808,777 |
| Deferred bond offering costs, net of accumulated amortization of $4,080,257 in 2004 and $3,684,097 in 2003 | 2,360,812 | 2,756,971 |
| Goodwill | 3,430,246 | 3,430,246 |
| Other assets | 4,034,937 | 4,576,800 |
| Total other assets | 138,878,830 | 120,114,002 |
| | $ 246,910,661 | $ 151,053,663 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current Liabilities | | |
| Current maturities of debentures | $ 17,316,070 | $ 4,809,470 |
| Current maturities of other long−term liabilities | 353,516 | 208,383 |
| Accounts payable and accrued expenses | 16,153,851 | 8,956,529 |
| Deferred income — turnkey drilling contracts with affiliated partnerships | 11,908,389 | 22,438,272 |
| Total current liabilities | 45,731,826 | 36,412,654 |
| Long−Term Liabilities | | |
| Debentures, less current portion | 29,160,630 | 43,285,230 |
| Other long−term liabilities, less current portion | 3,207,809 | 1,613,081 |
| | 32,368,439 | 44,898,311 |
| Minority Interest | 11,240,990 | 13,348,654 |
| Stockholders' Equity | | |
| 8% convertible preferred stock — $.0001 par value; authorized, 10,000,000 shares; issued and outstanding, 6,560,809 shares in 2004 and 6,507,729 shares in 2003 (aggregate liquidation preference $78,729,708 in 2004 and $78,092,748 in 2003) | 77,270,413 | 76,334,024 |
| Common stock — $.0001 par value; authorized, 100,000,000 shares; issued, 34,347,854 shares in 2004 and 17,349,070 shares in 2003 | 3,435 | 1,735 |
| Additional paid−in capital | 157,847,314 | 47,739,159 |
| Accumulated deficit | (77,689,476) | (67,729,178) |
| Accumulated other comprehensive income, net of applicable income taxes of $576,000 in 2004 and $517,000 in 2003 | 865,775 | 776,359 |
| | 158,297,461 | 57,122,099 |
| Less common stock in Treasury — at cost; 632,250 shares in 2004 and 2003 | 728,055 | 728,055 |
| | 157,569,406 | 56,394,044 |
| | $ 246,910,661 | $ 151,053,663 |

The accompanying notes are an integral part of these statements.

**Warren Resources, Inc. and Subsidiaries**
**CONSOLIDATED STATEMENTS OF OPERATIONS**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Revenues | | | |
| Turnkey contracts with affiliated partnerships | $ 10,529,883 | $ 11,300,646 | $ 5,841,110 |
| Oil and gas sales from marketing activities | 6,171,338 | 5,620,522 | 11,272,398 |
| Well services, 84%, 81% and 79% with affiliated partnerships, respectively | 1,070,004 | 1,167,564 | 1,895,453 |
| Oil and gas sales | 6,454,334 | 5,717,814 | 592,528 |
| Net gain (loss) on investments | (42,916) | 21,761 | 464,185 |
| Interest and other income | 2,088,994 | 1,340,059 | 5,257,842 |
| Gain on sale of unproved oil and gas properties | 120,193 | 494,497 | 4,286,774 |
| | 26,391,830 | 25,662,863 | 29,610,290 |
| Expenses | | | |
| Turnkey contracts | 12,932,124 | 7,284,653 | 4,965,426 |
| Cost of marketed oil and gas purchased from affiliated partnerships | 6,028,727 | 5,500,426 | 11,121,522 |
| Well services | 672,933 | 662,128 | 838,878 |
| Production and exploration | 3,935,137 | 3,811,595 | 1,325,764 |
| Depreciation, depletion, amortization and impairment | 4,022,725 | 3,249,860 | 9,930,162 |
| General and administrative | 8,116,164 | 4,496,034 | 6,277,792 |
| Interest | 493,977 | 1,528,069 | 6,312,631 |
| Contingent repurchase obligation | — | — | (3,064,661) |
| | 36,201,787 | 26,532,765 | 37,707,514 |
| Loss before provision for income taxes | (9,809,957) | (869,902) | (8,097,224) |
| Deferred income tax expense (benefit) | (59,000) | 129,000 | (471,000) |
| Net loss before minority interest and change in accounting principle | (9,750,957) | (998,902) | (7,626,224) |
| Minority interest | (209,341) | (112,263) | — |
| Net loss before change in accounting principle | (9,960,298) | (1,111,165) | (7,626,224) |
| Cumulative effect of change in accounting principle | — | (88,218) | — |
| Net loss | (9,960,298) | (1,199,383) | (7,626,224) |
| Less dividends and accretion on preferred shares | 6,590,886 | 4,561,543 | 16,206 |
| Net loss applicable to common stockholders | $ (16,551,184) | $ (5,760,926) | $ (7,642,430) |
| Basic and diluted loss per common share | $ (0.84) | $ (0.34) | $ (0.44) |
| Weighted average common shares outstanding | 19,739,048 | 16,827,857 | 17,339,869 |

The accompanying notes are an integral part of these statements.

# Warren Resources, Inc. and Subsidiaries
## CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (DEFICIT)
## Years ended December 31, 2004, 2003 and 2002

| | Preferred Stock | | Common Stock | | | | Accumulated Other | | Total Stockholders' |
|---|---|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Additional Paid−in Capital | Accumulated Deficit | Comprehensive Income | Treasury Stock | Equity (Deficit) |
| Balance at January 1, 2002 | — | — | 17,537,579 | 17,538 | 52,197,669 | (58,903,571) | 264,260 | (10,010) | (6,434,114) |
| Change in par value of common stock | — | — | — | (15,784) | 15,784 | — | — | — | — |
| Dividends declared on preferred stock | — | — | — | — | (16,206) | — | — | — | (16,206) |
| Shares issued for services | — | — | 23,695 | 2 | 86,902 | — | — | — | 86,904 |
| Conversion to common stock from convertible debt | — | — | 20,722 | 2 | 139,998 | — | — | — | 140,000 |
| Issuance of preferred stock, net of offering costs of $454,740 | 1,784,197 | 20,955,838 | — | — | — | — | — | — | 20,955,838 |
| Purchase of treasury stock | — | — | — | — | — | — | — | (811,573) | (811,573) |
| Comprehensive loss | | | | | | | | | |
| Net loss | — | — | — | — | — | (7,626,224) | — | — | (7,626,224) |
| Comprehensive loss | | | | | | | | | |
| Net change in unrealized gain on investment securities available for sale, net of applicable income taxes | — | — | — | — | — | — | 707,248 | — | 707,248 |
| Total comprehensive loss | | | | | | | | | (6,918,976) |
| Balance at December 31, 2002 | 1,784,197 | 20,955,838 | 17,581,996 | 1,758 | 52,424,147 | (66,529,795) | 971,508 | (821,583) | 7,001,873 |
| Retirement of common stock | — | — | (232,926) | (23) | (123,445) | — | — | 93,528 | (29,940) |
| Dividends declared on preferred stock | — | — | — | — | (4,272,297) | — | — | — | (4,272,297) |
| Issuance of preferred stock, net of offering costs of $2,048,730 | 4,723,532 | 55,088,940 | — | — | — | — | — | — | 55,088,940 |
| Accretion of preferred stock to redemption value | — | 289,246 | — | — | (289,246) | — | — | — | — |
| Comprehensive loss | | | | | | | | | |
| Net loss | — | — | — | — | — | (1,199,383) | — | — | (1,199,383) |
| Comprehensive loss | | | | | | | | | |
| Net change in unrealized gain on investment securities available for sale, net of applicable income taxes | — | — | — | — | — | — | (195,149) | — | (195,149) |
| Total comprehensive loss | | | | | | | | | (1,394,532) |
| Balance at December 31, 2003 | 6,507,729 | 76,334,024 | 17,349,070 | 1,735 | 47,739,159 | (67,729,178) | 776,359 | (728,055) | 56,394,044 |
| Issuance of common stock, net of offering costs | — | — | 16,793,980 | 1,679 | 115,802,018 | — | — | — | 115,803,697 |
| Shares issued from exercise of options | — | — | 186,056 | 19 | 744,205 | — | — | — | 744,224 |
| Shares issued from exercise of Class A Warrants | — | — | 8,482 | 1 | 84,819 | — | — | — | 84,820 |
| Conversion to common stock from debentures | — | — | 10,266 | 1 | 67,999 | — | — | — | 68,000 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Dividends declared on preferred stock | — | — | — | — | (6,282,213) | — | — | — | (6,282,213) |
| Issuance of preferred stock, net of offering costs of $9,232 | 53,080 | 627,716 | — | — | — | — | — | — | 627,716 |
| Accretion of preferred stock to redemption value | — | 308,673 | — | — | (308,673) | — | — | — | — |
| Comprehensive loss | | | | | | | | | |
| Net loss | — | — | — | — | — | (9,960,298) | — | — | (9,960,298) |
| Comprehensive loss | | | | | | | | | |
| Net change in unrealized gain on investment securities available for sale, net of applicable income taxes | — | — | — | — | — | — | 89,416 | — | 89,416 |
| Total comprehensive loss | | | | | | | | | (9,870,882) |
| Balance at December 31, 2004 | 6,560,809 | $ 77,270,413 | 34,347,854 | $ 3,435 | $ 157,847,314 | $ (77,689,476) | $ 865,775 | $ (728,055) | $ 157,569,406 |

The accompanying notes are an integral part of these statements.

**Warren Resources, Inc. and Subsidiaries**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Cash flows from operating activities: | | | |
| Net loss | $ (9,960,298) | $ (1,199,383) | $ (7,626,224) |
| Adjustments to reconcile net loss to net cash provided by (used in) operating activities: | | | |
| Accretion of discount on available for sale debt securities | (669,882) | (563,495) | (514,818) |
| Amortization and write−off of deferred bond offering costs | 396,160 | 633,051 | 515,886 |
| Gain on sale of U.S. Treasury bonds — available for sale | (58,693) | (132,827) | (28,104) |
| Depreciation, depletion, amortization and impairment | 4,022,725 | 3,249,860 | 9,930,162 |
| Accretion of asset retirement obligation | 52,771 | 62,452 | — |
| Cumulative effect of accounting change | — | 88,218 | — |
| Gain on sale of oil and gas properties | (120,193) | (494,497) | (4,286,774) |
| Common stock issued for services | — | — | 86,904 |
| Non−cash compensation | — | — | 200,000 |
| Deferred tax expense (benefit) | (59,000) | 129,000 | (471,000) |
| Change in assets and liabilities: | | | |
| (Increase) decrease in trading securities | 26,906 | (122,769) | 127,606 |
| (Increase) decrease in accounts receivable — trade | 904,255 | 4,509,303 | (902,157) |
| (Increase) decrease in accounts receivable from affiliated partnerships | 245,974 | 531,981 | (119,591) |
| Decrease in other assets | 2,362,056 | 810,183 | 2,886,299 |
| Increase (decrease) in accounts payable and accrued expenses | 7,122,794 | 3,633,658 | (2,704,532) |
| Decrease in deferred income from affiliated partnerships | (10,529,883) | (5,223,496) | (677,861) |
| Decrease in contingent repurchase obligation to affiliated partnerships | — | — | (3,064,661) |
| Increase (decrease) in other long−term liabilities | 1,757,769 | (633,611) | 548,200 |
| Net cash provided by (used in) operating activities | (4,506,539) | 5,277,628 | (6,100,665) |
| Cash flows from investing activities: | | | |
| Purchases of oil and gas properties | (27,093,223) | (12,699,505) | (4,699,453) |
| Purchases of property and equipment | (9,725) | (40,043) | (50,592) |
| Proceeds from the sale of oil and gas properties, net of selling fees | 120,193 | 494,497 | 12,874,512 |
| Proceeds from the sale of property and equipment | 24,000 | 52,353 | — |
| Purchases of U.S. Treasury bonds — available for sale | (2,367,786) | (5,692,731) | (14,906) |
| Proceeds from U.S. Treasury bonds — available for sale | 293,858 | 723,442 | 845,081 |
| (Increase) decrease in restricted cash | — | 3,637,775 | (3,637,775) |
| Net cash provided by (used in) investing activities | (29,032,683) | (13,524,212) | 5,316,867 |
| Cash flows from financing activities: | | | |
| Payments on long−term debt | (1,620,679) | (1,911,336) | (2,813,965) |
| Issuance of common stock, net | 116,632,741 | — | — |
| Issuance of preferred stock, net | 126,730 | 14,304,156 | 3,861,718 |
| Dividends paid on preferred stock | (6,207,684) | (2,772,233) | — |
| Purchase of treasury stock | — | (29,940) | (2,624) |
| Net cash provided by financing activities | 108,931,108 | 9,590,647 | 1,045,129 |
| Net increase in cash and cash equivalents | 75,391,886 | 1,344,063 | 261,331 |
| Cash and cash equivalents at beginning of year | 24,528,999 | 23,184,936 | 22,923,605 |

| | | | |
|---|---|---|---|
| Cash and cash equivalents at end of year | $ 99,920,885 | $ 24,528,999 | $ 23,184,936 |

The accompanying notes are an integral part of these statements.

**Warren Resources, Inc. and Subsidiaries**
**CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)**
**Year ended December 31,**

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Supplemental disclosure of cash flow information | | | |
| Cash paid for interest, net of amount capitalized | $ 45,082 | $ 895,018 | $ 5,770,006 |
| Cash paid for income taxes | $ — | $ — | $ — |
| Noncash investing and financing activities: | | | |
| Conversion to common stock from convertible debt | 68,000 | — | 140,000 |
| Exchange of 2007 Sinking Fund Bond for preferred stock | — | 3,858,392 | 978,600 |
| Exchange of 2017 Sinking Fund Bond for preferred stock | — | 864,160 | — |
| Accounts receivable consisting of service credits relating to the sale of Pinnacle | — | — | 450,000 |
| Other assets consisting of deferred payments relating to the conveyance of oil and gas property | — | — | 5,818,183 |
| Purchase of treasury stock of $808,949 and incurrence of noncash compensation of $200,000 through the issuance of a noninterest−bearing note (see note D) | — | — | 1,008,949 |
| Accrued preferred stock dividend | 1,574,594 | 1,500,064 | 16,206 |
| Preferred stock issued to minority interest (see note J) | 500,986 | 3,782,664 | — |
| Preferred stock issued to acquire property (see note I) | — | 7,972,000 | — |
| During 2003, the Company acquired affiliated L.L.C. interests in ex−change for 1,641,628 shares of preferred stock (see note J). In conjunction with the acquisition, assets were acquired and liabilities were assumed as follows: | | | |
| Estimated fair value of assets acquired | | $ 28,346,462 | |
| Liabilities assumed | | 8,646,926 | |
| Estimated fair value of preferred stock | | $ 19,699,536 | |
| During 2003, the Company recorded the cumulative effect of SFAS 143 for asset retirement obligations, as follows: | | | |
| Increase to oil and gas properties | | $ 557,465 | |
| Increase of asset retirement obligation | | 645,683 | |
| Cumulative effect of accounting change | | $ 88,218 | |
| During 2002, the Company acquired affiliated L.L.C. interests in ex−change for 1,342,960 shares of preferred stock (note J). In conjunction with the acquisition, assets were acquired and liabilities were assumed as follows: | | | |
| Estimated fair value of assets acquired | | | $ 25,256,708 |
| Liabilities assumed | | | 9,141,188 |
| Estimated fair value of preferred stock | | | $ 16,115,520 |

The accompanying notes are an integral part of these statements.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**December 31, 2004, 2003 and 2002**

## NOTE A — ORGANIZATION AND ACCOUNTING POLICIES

***Nature of Operations***

Warren Resources, Inc. (the “Company” or “Warren”), was formed on June 12, 1990 under the laws of the State of New York for the purpose of acquiring and developing oil and gas properties. On September 5, 2002, the Company changed its state of incorporation to Delaware. On July 7, 2004, the Company changed its state of incorporation to Maryland. As a result, all shares of the Company’s stock were converted into shares of the Maryland Corporation. The Company’s properties are primarily located in New Mexico, North Dakota, Texas, Wyoming and California. In addition, the Company serves as the managing general partner (the “MGP”) to affiliated partnerships and joint ventures.

***Principles of Consolidation***

The consolidated financial statements include the accounts of the Company, its wholly owned subsidiaries, Warren Development Corp., Warren Drilling Corp., Warren Management Corp., Warren E&P, Inc. (formerly known as Petroleum Development Corp), and certain partnerships where the Company has majority control (Note J). All significant intercompany accounts and transactions have been eliminated in consolidation.

Historically, the Company entered into joint venture agreements with limited partnerships whereby the Company assigned a 75% (before payout) working interest in an oil and gas lease to a limited partnership while retaining a 25% (before payout) working interest. This ownership interest is an undivided interest in the mineral rights and each owner is responsible for its designated well expenditures. In exchange for the 75% working interest, the limited partners pay intangible drilling costs and, if a well is successful, the Company pays completion costs, including lease and well equipment. Payout is achieved when the limited partners in a particular partnership receive distributions equal to 100% of their original investment. Distributions received by the participants are determined by the revenues generated from the wells in each of the various partnerships less any applicable lease operating expenses. Once payout is achieved, the Company has a total interest of 55% in the net revenue generated from all wells assigned to a particular partnership. The Company primarily incurs lease acquisition costs and completion costs, including lease and well equipment, on wells developed in these partnerships and joint ventures. The Company proportionately consolidates its share of the costs incurred on undivided working interests in the post−1998 partnerships, in which it does not have majority control.

***Oil and Gas Properties***

The Company uses the successful efforts method of accounting for oil and gas properties. Under this methodology, costs incurred to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized.

Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs and costs of carrying and retaining unproved properties are expensed.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on the Company’s experience of successful drilling, terms of leases and historical lease expirations.

Capitalized costs of producing oil and gas properties are depleted by the units−of−production method on a field−by−field basis. Lease costs are depleted using total proved reserves while lease equipment and intangible development costs are depleted using proved developed reserves. The Company’s proved properties are evaluated on a field−by−field basis for impairment. An impairment loss is indicated whenever net capitalized costs exceed expected future net cash flow based on engineering estimates. In this circumstance, the

Company recognizes an impairment loss for the amount by which the carrying value of the properties exceeds the estimated fair value (based on discounted cash flow).

On the sale or retirement of a complete unit of a proved property, the cost and related accumulated depletion and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized. On the retirement or sale of a partial unit of proved property, the cost is charged to accumulated depletion and amortization with a resulting gain or loss recognized in earnings.

On the sale of an entire interest in an unproved property, a gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

***Revenue Recognition***

Affiliated partnerships enter into agreements with the Company to drill wells to completion for a fixed price. The Company, in turn, enters into drilling contracts primarily with unrelated parties to drill wells on a day work basis. Therefore, if problems are encountered on a well, the cost of that well will increase and gross profit will decrease and could result in a loss on the well. The Company recognizes revenue from the turnkey drilling agreements on a proportional performance method as services are performed. When estimates of future revenues and expenses on a specific contract indicate that a loss will be incurred, the total estimated loss is accrued.

Oil and gas sales result from undivided interests held by the Company in various oil and gas properties. Sales of natural gas and oil produced are recognized when delivered to or picked up by the purchaser. Oil and gas sales from marketing activities result from sales by the Company of oil and gas produced by affiliated joint ventures and partnerships and are recognized when delivered to purchasers.

***Cash and Cash Equivalents***

The Company considers all highly liquid investments with maturities of three months or less when acquired to be cash equivalents. The Company maintains its cash and cash equivalents in bank deposit accounts which exceed federally insured limits. At December 31, 2004, the Company had approximately 76% and 24% of its cash and cash equivalents with two financial institutions. At December 31, 2003, the Company had approximately 99% of its cash and cash equivalents with one financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on cash and cash equivalents.

***Accounts Receivable***

Accounts receivable include amounts due from affiliated partnerships and joint ventures for advances and expenditures made by the Company on behalf of such entities, as well as trade receivables for oil and gas purchasers, substantially all of wham are located in California and Wyoming. Credit is extended based on evaluation of a customer’s financial condition and, generally, collateral is not required. Accounts receivable under joint operating agreements generally have a right of offset against future oil and gas revenues if a producing well is completed. Accounts receivable are due within 30 days and are stated at amounts due from customers net of an allowance for doubtful accounts when the Company believes collection is doubtful. Accounts outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time trade accounts receivable are past due, the Company’s previous loss history, the customer’s current ability to pay its obligation to the Company, and the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

***Investments***

The Company classifies its debt and equity securities into two categories: trading securities and available−for−sale securities. Trading securities, classified as current assets, are recorded at fair value with net unrealized gains or losses included in the determination of net earnings. Available−for−sale securities are measured at fair value, with net unrealized gains and losses excluded from net earnings and reported as other comprehensive income (loss). Current available−for−sale securities represent the par value of zero coupon Treasury Bonds associated with our current redeemable debt. Realized gains and losses are determined on the basis of specific identification of the securities.

***Offering Costs***

Costs incurred in connection with the issuance of long−term debt are capitalized and amortized over the term of the related debt using the effective interest rate method. Costs associated with the issuance of preferred and common stock are reflected as a reduction of proceeds. The preferred stock discount is accreted to the liquidation value over seven years from the date of issuance.

***Income Taxes***

Deferred income taxes are recognized for the tax consequences in future years of differences between the tax basis of assets and liabilities and their financial reporting amounts based on enacted tax laws and statutory rates applicable to the period in which the differences are expected to affect taxable income. Valuation allowances are established when, in management’s opinion, it is more likely than not that a portion or all of the deferred tax assets will not be realized.

***Use of Estimates***

In preparing financial statements, accounting principles generally accepted in the United States of America require management to make estimates and assumptions in determining the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

***Gas Imbalances***

The Company follows the sales method of accounting for gas imbalances. A liability is recorded when the Company’s excess takes of natural gas volumes exceed its estimated remaining recoverable reserves.

No receivables are recorded for those wells where the Company has taken less than its ownership share of gas production. The Company has no significant gas imbalances.

***Capitalized Interest***

Interest of approximately $5,900,000, $5,700,000 and $1,400,000 was capitalized during the years ended December 31, 2004, 2003 and 2002, respectively, relating to California and Wyoming properties on which exploration activities were in progress during 2004, 2003 and 2002. Approximately $1,933,000 of interest previously capitalized was charged against the proceeds of the conveyance of certain of these unproved properties in 2002 (see Note C).

***Accounting For Long−Lived Assets***

The Company reviews property and equipment for impairment whenever indicators of impairment are present to determine if the carrying amounts exceed the estimated future net cash flows to be realized. Impairment losses are recognized based on the estimated fair value of the asset.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

***Stock Based Compensation***

The Company has a stock−based employee plan, which is described more fully in Note E to the financial statements. The Company accounts for stock based employee awards using the intrinsic value method for its employee option plans in which compensation is recognized only when the fair value of the underlying stock exceeds the exercise price of the option at the date of grant. The exercise price of all options equaled or exceeded market price of the stock at the date of grant. Accordingly, no compensation cost has been recognized for the options issued. Had compensation cost been determined based on the fair value provisions of FASB Statement No. 123, Accounting for Stock−Based Compensation, the Company's net loss would have been adjusted to the pro forma amounts for the years ended as indicated below. Stock based awards to non−employees are accounted for under the fair value method of accounting.

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Net loss applicable to common stockholders | | | |
| As reported | $ (16,551,184) | $ (5,760,926) | $ (7,642,430) |
| Deduct: Stock−based employee compensation expense under SFAS 123 | (963,483) | (2,147,458) | (409,682) |
| Pro forma | $ (17,514,667) | $ (7,908,384) | $ (8,052,112) |
| Basic and diluted loss per common share: | | | |
| As reported | $ (0.84) | $ (0.34) | $ (0.44) |
| Pro forma | $ (0.89) | $ (0.47) | $ (0.46) |

The fair value of each grant is estimated on the date of grant using the Black−Scholes options−pricing model with the following weighted−average assumptions used for grants in 2004, 2003 and 2002, respectively: No expected dividends, expected volatility of 28%, 31% and 33%, risk−free interest rate of 3.60%, 3.25% and 3.22% and expected lives of 5 years for incentive options issued in 2004, 2003 and 2002, respectively. The volatility assumptions were developed using a peer group of similar energy companies. The weighted average fair value of the options issued in 2004, 2003 and 2002 was $2.90, $1.57 and $0.06, respectively.

The Black−Scholes options valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions, including the expected stock price volatility. Because the Company's employee options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its employee options.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

***Property and Equipment***

Property and equipment are stated at cost and are depreciated using the straight−line method over the estimated useful lives of the assets, ranging from three through 10 years. Major classes of property and equipment consisted of the following at December 31:

| | 2004 | 2003 |
|---|---|---|
| Equipment | $ 957,913 | $ 1,004,891 |
| Automobiles and trucks | 30,433 | 30,433 |
| Furniture and fixtures | 152,704 | 145,260 |
| Land and buildings | 99,237 | 119,736 |
| Office equipment | 101,371 | 99,090 |
| | 1,341,658 | 1,399,410 |
| Less accumulated depreciation, depletion, amortization and impairment | 946,214 | 807,747 |
| | $ 395,444 | $ 591,663 |

***Earnings (Loss) Per Common Share***

Basic earnings (loss) per common share is computed by dividing the net earnings (loss) applicable to common stockholders by the weighted average number of common shares outstanding for the period. Diluted earnings (loss) per share is based on the assumption that stock options and warrants are converted into common shares using the treasury stock method and convertible bonds and debentures are converted using the if−converted method. Conversion or exercise is not assumed if the results are antidilutive.

Potential common shares relating to options, warrants, preferred stock and convertible bonds and debentures excluded from the computations of diluted earnings (loss) per share because they are antidilutive are as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| Employee stock options | 2,625,206 | 2,241,012 | 1,514,459 |
| Convertible bonds and debentures | 5,188,788 | 5,387,820 | 5,768,903 |
| Preferred stock | 6,560,809 | 6,507,729 | 1,784,197 |
| Warrants | 3,109,643 | 180,625 | — |

Preferred stock is convertible from the date of issuance until redemption at 100% of the redemption price amount into common stock of the Company at a conversion rate between 1 to 1 and 1 to .5 (Note E).

The Convertible Bonds and Debentures may be converted from the date of issuance until maturity at 100% of principal amount into common stock of the Company at prices ranging from approximately $5.00 to $50.00 (Note D).

***Goodwill***

The Company adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, effective January 1, 2002, and as such, has not subsequently recorded any amortization of goodwill. Under the new rules, the Company only adjusts the carrying amount of goodwill or indefinite life intangible assets upon an impairment.

The Company retained CBIZ Valuation Group, LLC to assist management in their development of the fair value analysis in conducting the testing for impairment of its goodwill. The results of the analysis indicated that no impairment of goodwill had occurred. The Company has set the beginning of the second quarter (April) as the annual period for goodwill impairment testing. The results will be reported no later than June 30 of each year.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

***Asset Retirement Obligations***

In June 2001, the Financial Accounting Standard Board issued SFAS No. 143, “Accounting for Asset Retirement Obligations” which requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long−lived asset. This statement is effective for fiscal years beginning after June 15, 2002. The Company adopted SFAS No. 143 on January 1, 2003 and recorded a net asset of $557,000, a related liability of $645,000 (using a 10% discount rate) and a cumulative effect of change in accounting principle on prior years of $88,000. As of December 31, 2002, the Company had an allowance for asset retirement obligations of $434,000. During 2004 and 2003, the asset retirement liability was increased by approximately $53,000 and $62,000, respectively, as a result of accretion and was recorded as interest expense. Also during 2004 and 2003, the Company sold certain non−strategic oil and gas properties deemed not commercially productive which resulted in a decrease to the asset retirement liability of approximately $73,000, and $255,000 respectively. The Company has treasury bills held in escrow with a fair market value of $2,766,000 that are legally restricted for potential plugging and abandonment liability in the Wilmington field.

The following illustrates the activity incurred in the asset retirement obligation since adoption at December 31:

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| Balance at beginning of year | $ 896,448 | $ 1,079,884 |
| Liabilities incurred in current year | 7,904 | 8,358 |
| Liabilities eliminated in current year | (73,291) | (254,246) |
| Accretion expense | 52,771 | 62,452 |
| Carrying Amount | $ 883,832 | $ 896,448 |

***Recent Accounting Pronouncements***

In December 2004, the FASB issued SFAS No. 123(R), “Share−Based Payment”. This Statement revises SFAS No. 123, “Accounting for Stock−Based Compensation” and supersedes APB Opinion No. 25, “Accounting for Stock Issued to Employees.” SFAS No. 123(R) focuses primarily on the accounting for transactions in which an entity obtains employee services in share−based payment transactions. SFAS No. 123(R) requires companies to recognize in the statement of operations the cost of employee services received in exchange for awards of equity instruments based on the grant−date fair value of those awards. This Statement is effective as of the first reporting period that begins after June 15, 2005. Accordingly, the Company will adopt SFAS No. 123(R) in its third quarter of fiscal 2005. The Company is currently evaluating the provisions of SFAS No. 123(R) and the impact that it will have on its share based employee compensation programs. See “Stock−based Compensation” herein for the effect on net income and earnings per share as if the fair value based method provided by SFAS No. 123 had been applied.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**NOTE B — INVESTMENTS**

The amortized cost, unrealized gains and estimated fair values of the Company's available−for−sale securities held are summarized as follows:

| | December 31, | |
|---|---|---|
| | 2004 | 2003 |
| U.S. Treasury Bonds, stripped of interest, maturing 2007 through 2023, aggregate par value of $26,048,000 and $23,414,000, respectively | | |
| Amortized cost | $ 16,723,486 | $ 13,920,985 |
| Gross unrealized gains | 1,438,567 | 1,290,150 |
| Estimated fair value | $ 18,162,053 | $ 15,211,135 |

During 2004, 2003 and 2002, the Company recognized approximately $106,000, $(87,000) and $461,000, respectively, of unrealized gains (losses) on its trading securities and $63,000 $109,000 and $28,000, respectively, of realized gains from its investments in trading and available−for−sale securities. The realized gains for each year results from the release of such securities due to cash distributions to investors of affiliated partnerships made from proceeds from sales of oil and gas and the release of the Company's obligation related to securing its commitment under certain repurchase agreements (Note G). At December 31, 2004, the Company's gross unrealized losses were immaterial and were netted against gross unrealized gains for the year.

In January 2005, the Company called its 12% Sinking Fund Bonds due December 31, 2007 and its 12% Sinking Fund Convertible Bonds due December 31, 2017 for full redemption on March 31, 2005 (see Note D). The 2007 and 2017 bonds are secured by treasuries having a fair value of approximately $4,121,000 and $762,000, respectively, and an amortized cost of approximately $4,142,000 and $703,000, respectively. These treasuries will be released to the Company upon redemption.

The amortized cost and estimated fair values of available−for−sale securities, by contractual maturity at December 31, 2004, and reflecting investments released as a result of debentures being called in 2005 are shown below.

| | Amortized Cost | Estimated Fair Value |
|---|---|---|
| Due within one year | $ 4,845,037 | $ 4,883,480 |
| Due after one year through five years | 569,777 | 651,995 |
| Due after five years through ten years | 6,682,788 | 7,168,344 |
| Due after ten years | 4,625,884 | 5,458,234 |
| Total | $ 16,723,486 | $ 18,162,053 |

**NOTE C — SALE OF ASSETS**

*Kirby Decker Acreage*

During June 2002, the Company initiated a plan to dispose of its unproved Kirby Decker acreage, which was completed in August 2002. The Company sold all of its 24,133 gross (22,075 net) acres, which was located in Bighorn County, Montana for proceeds of approximately $895,000. In connection with the disposal, the Company determined that the carrying value of this property exceeded its fair value. Accordingly, an impairment expense of approximately $1,100,000, was included as part of depreciation, depletion, amortization and impairment expense in the second quarter of 2002. The fair value was based on the estimated selling price of the property.

*Atlantic Rim Project*

The Company signed a property exchange and development agreement with Anadarko E&P Company LP (“Anadarko”), a wholly owned subsidiary of Anadarko Petroleum Corporation, on December 13, 2002. As a result of these transactions, the Company effectively sold a partial interest in unproved properties and recognized a gain of approximately $4,300,000 after recovery of its unproved property costs.

Pursuant to the exchange agreement, the Company conveyed to Anadarko its interest in certain coalbed methane properties of approximately 86,000 net acres within a defined area of mutual interest (“AMI”) located in the Washakie Basin, Carbon County, Wyoming. Anadarko conveyed to the Company its interest in certain acreage in the AMI with each party owning a 50% interest in approximately 141,000 net acres in the AMI.

The Company received $12,000,000 in cash and a deferred payment commitment of $6,000,000 for the three (3) year period commencing August 1, 2002 and a reimbursement of prior drilling expenses of approximately $2,200,000. Anadarko will pay for the Company’s proportionate share of AMI costs, as defined, associated with the exploration and development of oil and gas properties for up to $2,000,000 for each of the three years until Anadarko has paid $2,000,000 for each such twelve−month period. Subject to mutually agreed upon force majeure events, on each August 1, Anadarko will pay the Company the difference, if any, between $2,000,000 and the amount of costs and expenses actually paid by Anadarko during the preceding year. At December 31, 2003, the Company had $2,000,000 in deferred credits remaining, which were utilized in 2004.

**NOTE D — LONG−TERM DEBT**

Debentures consist of the following at December 31:

| | 2004 | 2003 |
|---|---|---|
| Sinking Fund Debentures, due December 31, 2007, bearing interest at 12%, due in monthly payments. Annual sinking fund payments, based on 20% of total outstanding principal, commenced on December 31, 2002. As of December 31, 2004 and 2003, principal collateralized by $4,518,000 and $3,206,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2007.(1) | $ 9,036,000 | $ 9,616,000 |
| Secured Convertible Debentures, due December 31, 2009, bearing interest at 12%, due in monthly payments. As of December 31, 2004 and 2003, principal collateralized by $770,000 and $790,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2009.(2) | 770,000 | 790,000 |
| Secured Convertible Bonds, due December 31, 2010, bearing interest at 12%, due in monthly payments. As of December 31, 2004 and 2003, principal collateralized by $1,700,000 and $1,705,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2010.(2) | 1,700,000 | 1,705,000 |
| Sinking Fund Convertible Debentures, due December 31, 2010, bearing interest at 13.02%, due in monthly payments. Annual Sinking Fund payments, based on 8.33% of total outstanding principal, commenced on December 31, 1999. As of December 31, 2004 and 2003, principal collateralized by $7,187,000 and $6,107,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2010.(2) | 14,372,200 | 14,655,200 |

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

| | 2004 | 2003 |
|---|---|---|
| Sinking Fund Convertible Debentures, due December 31, 2015, bearing interest at 13.02%, due in monthly payments. Annual Sinking Fund payments, based on 5.88% of total outstanding principal, commenced on December 31, 1999. As of December 31, 2004 and 2003, principal collateralized by $4,106,000 and $3,469,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2015.(3) | 11,632,500 | 11,792,500 |
| Secured Convertible Bonds, due December 31, 2016, bearing interest at 12%, due in monthly payments. As of December 31, 2004 and 2003, principal collateralized by $1,305,000 and $1,365,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2016.(2) | 1,305,000 | 1,365,000 |
| Sinking Fund Convertible Debentures, due December 31, 2017, bearing interest at 12%, due in monthly payments. Annual Sinking Fund payments, based on 5.56% of total outstanding principal, commenced on December 31, 1999. As of December 31, 2004 and 2003, principal collateralized by $1,407,000 and $1,223,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2017.(1) | 5,040,000 | 5,500,000 |
| Secured Convertible Bonds, due December 31, 2020, bearing interest at 12%, due in monthly payments. As of December 31, 2004 and 2003, principal collateralized by $1,485,000 and $1,485,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2020.(3) | 1,485,000 | 1,485,000 |
| Secured Convertible Bonds, due December 31, 2022, bearing interest at 12%, due in monthly payments. As of December 31, 2004 and 2003, principal collateralized by $1,136,000 and $1,186,000 respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2022.(3) | 1,136,000 | 1,186,000 |
| | 46,476,700 | 48,094,700 |
| Less current maturities | 17,316,070 | 4,809,470 |
| Long−term portion | $ 29,160,630 | $ 43,285,230 |

Other long−term liabilities consist of the following at December 31:

| | 2004 | 2003 |
|---|---|---|
| Other miscellaneous long−term liabilities, consisting of debt collateralized by treasury stock, asset retirement obligations and litigation provision | $ 3,561,325 | $ 1,821,464 |
| Less current maturities | 353,516 | 208,383 |
| Long−term portion | $ 3,207,809 | $ 1,613,081 |

(1) In January 2005, the Company called for full redemption on March 31, 2005, certain sinking fund debentures. The 2007 and 2017 bonds were called at a premium of 2% and 6%, respectively, which will result in an expense of approximately $483,000 in the first quarter of 2005 relating to retirement of this debt. Also in the first quarter of 2005, the Company will write off approximately $731,000 of deferred offering costs relating to these bonds. This redemption will result in a release of treasuries to the Company, having a fair market value of approximately $4,883,000 at December 31, 2004 (see Note B) and will decrease annual interest expense by approximately $1,689,000.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

(2) Debentures can be called at a premium of 10%, if the Company's stock trades at or above 133% of the conversion price for a period of ninety consecutive trading days.

(3) Debentures can be called at par, if the Company's stock trades at or above 133% of the conversion price for a period of ninety consecutive trading days.

During 2002, the Company entered into an agreement to purchase 702,500 shares of common stock from a shareholder through the issuance of a noninterest−bearing note. The company discounted the non−interest bearing note at 10% and the outstanding balance at December 31, 2004 and 2003 was approximately $854,000 and $925,000, respectively, net of discount of approximately $372,000 and $462,000, which is included in other long−term liabilities. The note requires monthly payments of $13,333 until August 2012 and is collateralized by the treasury stock. In the event of default as defined by the agreement, the only remedy by the note−holder will be the issuance of the common stock.

During 2003 and 2002, the Company exchanged preferred stock for 2007 debentures with an outstanding principal of $3,858,000 and $979,000, respectively. Also, during 2003, the Company exchanged preferred stock for 2017 debentures with an outstanding principal of $864,000. The estimated fair value of the preferred stock, which was based on sales to third−party accredited investors, equaled the carrying value of the debentures. As such, no gain or loss was recognized for the exchange.

The Convertible Bonds and Debentures may be converted from the date of issuance until maturity at 100% of principal amount into common stock of the Company at prices which generally increase over the term of the bonds and debentures and range from approximately $5.00 to $50.00. In 2004, 2003, and 2002, debenture holders converted $68,000, $0 and $85,000 principal amount of notes into approximately 10,266, 0 and 8,500 shares of common stock, respectively. Additionally during 2002, the Company issued approximately 12,222 shares of common stock to certain exchange bond holders. Conversion of debt would increase the number of shares outstanding at December 31 as follows:

| 2004 | Maturity Date | Outstanding Principal Amount | Per Share Conversion Price | Common Shares if Converted |
|---|---|---|---|---|
| Sinking Fund 12% Bond | December 31, 2007 | $ 9,036,000 | $ — | — |
| Secured Convertible 12% Bond | December 31, 2009 | 770,000 | 9.00 | 85,556 |
| Secured Convertible 12% Bond | December 31, 2010 | 1,700,000 | 9.00 | 188,889 |
| Sinking Fund 13.02% Bond | December 31, 2010 | 14,372,200 | 5.00 | 2,874,440 |
| Sinking Fund 13.02% Bond | December 31, 2015 | 11,632,500 | 8.00 | 1,454,063 |
| Secured Convertible 12% Bond | December 31, 2016 | 1,305,000 | 9.00 | 145,000 |
| Sinking Fund 12% Bond | December 31, 2017 | 5,040,000 | 15.00 | 336,000 |
| Secured Convertible 12% Bond | December 31, 2020 | 1,485,000 | 25.00 | 59,400 |
| Secured Convertible 12% Bond | December 31, 2022 | 1,136,000 | 25.00 | 45,440 |
| | | $ 46,476,700 | | 5,188,788 |

| 2003 | Maturity Date | Outstanding Principal Amount | Per Share Conversion Price | Common Shares if Converted |
|---|---|---|---|---|
| Sinking Fund 12% Bond | December 31, 2007 | $ 9,616,000 | $ — | — |
| Secured Convertible 12% Bond | December 31, 2009 | 790,000 | 8.00 | 98,750 |
| Secured Convertible 12% Bond | December 31, 2010 | 1,705,000 | 8.00 | 213,125 |
| Sinking Fund 13.02% Bond | December 31, 2010 | 14,655,200 | 5.00 | 2,931,040 |
| Sinking Fund 13.02% Bond | December 31, 2015 | 11,792,500 | 8.00 | 1,474,063 |
| Secured Convertible 12% Bond | December 31, 2016 | 1,365,000 | 8.00 | 170,625 |
| Sinking Fund 12% Bond | December 31, 2017 | 5,500,000 | 15.00 | 366,667 |
| Secured Convertible 12% Bond | December 31, 2020 | 1,485,000 | 20.00 | 74,250 |
| Secured Convertible 12% Bond | December 31, 2022 | 1,186,000 | 20.00 | 59,300 |
| | | $ 48,094,700 | | 5,387,820 |

| 2003 | Maturity Date | Outstanding Principal Amount | Per Share Conversion Price | Common Shares if Converted |
|---|---|---|---|---|
| Sinking Fund 12% Bond | December 31, 2007 | $ 14,376,000 | $ — | — |
| Secured Convertible 12% Bond | December 31, 2009 | 790,000 | 8.00 | 98,750 |
| Secured Convertible 12% Bond | December 31, 2010 | 1,715,000 | 8.00 | 214,375 |
| Sinking Fund 13.02% Bond | December 31, 2010 | 14,780,200 | 5.00 | 2,956,040 |
| Sinking Fund 13.02% Bond | December 31, 2015 | 12,137,500 | 8.00 | 1,517,188 |
| Secured Convertible 12% Bond | December 31, 2016 | 1,460,000 | 8.00 | 182,500 |
| Sinking Fund 12% Bond | December 31, 2017 | 6,590,000 | 10.00 | 659,000 |
| Secured Convertible 12% Bond | December 31, 2020 | 1,635,000 | 20.00 | 81,750 |
| Secured Convertible 12% Bond | December 31, 2022 | 1,186,000 | 20.00 | 59,300 |
| | | $ 54,669,700 | | 5,768,903 |

Each year, holders of the Secured Convertible Debentures and Sinking Fund Convertible Debentures may tender to the Company up to 10% of the aggregate debentures outstanding.

The estimated principal that can be tendered by the Secured Convertible and Sinking Fund Debenture holders, including contractual maturities and the 2007 and 2017 Debentures called in January 2005, is as follows:

| | |
|---|---|
| Fiscal year ending December 31 | |
| 2005 | $ 17,316,070 |
| 2006 | 2,916,063 |
| 2007 | 2,624,457 |
| 2008 | 2,362,011 |
| 2009 | 2,580,487 |
| Thereafter | 18,677,612 |
| | $ 46,476,700 |

The Company has annual sinking fund requirements to purchase zero coupon U.S. Treasury Bonds as collateral for our outstanding debentures.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Annual sinking fund requirements are as follows:

| | | |
|---|---|---|
| Fiscal year ending December 31 | | |
| 2005 | $ | 1,420,035 |
| 2006 | | 1,521,984 |
| 2007 | | 1,588,860 |
| 2008 | | 1,653,299 |
| 2009 | | 1,720,777 |
| Thereafter | | 4,982,147 |
| | $ | 12,887,102 |

**NOTE E — STOCKHOLDERS' EQUITY**

On December 16, 2004, the Company sold 9,500,000 shares of common stock in an initial public offering for aggregate gross proceeds of $71,250,000. After deducting the underwriters' commission and offering expenses, the Company received net proceeds of approximately $65,263,000. On December 22, 2004, the underwriters exercised their over−allotment option for an additional 1,425,000 shares of the Company's common stock for additional gross proceeds of $10,687,500 and net proceeds of approximately $9,939,000, after deducting the underwriters' commission and offering expenses.

During 2004 the Company raised $19,950,000 through the private placement of 2,850,000 shares of common stock and issued 1,425,000 warrants to five institutional investors. The Company also sold 25,000 shares of its common stock for $175,000 and issued 12,500 warrants to a single investor. Additionally in November 2004, the Company completed an equity transaction that raised gross proceeds of $21,000,000, net proceeds after commission was $20,492,000, through the private placement of 3,000,000 shares of common stock and issued 1,500,000 warrants to purchase shares of common stock. The warrants consist of Class A and Class B warrants, which expire in five years and have an exercise price of $10 and $12.50, respectively.

During 2004, the Company issued 186,056 shares of common stock to employees who exercised options at an exercise price of $4 per share. Also during 2004, the Company issued 8,482 shares of common stock to an individual investor who exercised Class A warrants at $10 per share.

During 2004, the Company issued 8,600 shares of common stock to certain 2010 Sinking Fund Debenture holders, convertible at $5 per share and 1,666 shares of common stock to 2017 Sinking Fund Debenture holders, convertible at $15 per share.

During 2004, 2003 and 2002, the Company issued 11,331, 1,320,164 and 359,687 shares respectively, of redeemable convertible preferred stock ("preferred stock") through a private placement with accredited investors at a price of $12 per share for gross proceeds of $135,972, $15,841,968 and $4,316,244 respectively. Also, during 2004, 2003 and 2002, the Company issued 41,749, 3,005,186 and 1,342,960 shares respectively, of preferred stock to its affiliated limited partnerships under a partnership recapitalization offering at a price of $12 per share based on third−party sales to accredited investors (see Note J). The Company also exchanged 393,522 and 81,550 shares of preferred stock for debentures in 2003 and 2002, respectively (see Note D). The preferred stock has an 8% cumulative dividend, payable quarterly. Preferred dividends of approximately $1,600,000 and $1,500,000 were accrued at December 31, 2004 and 2003 and were paid in the following January. The holders of the preferred stock are not entitled to vote except as defined by the agreement or as provided by applicable law. The preferred stock may be voluntarily converted at the election of the holder, commencing one year after the date of issuance. Preferred stock outstanding is convertible into common

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

stock of the Company based on the table below. The conversion rate is subject to adjustment as defined by the agreement.

| | Preferred to Common |
|---|---|
| Period | |
| Until June 30, 2005 | 1 to 1(1) |
| July 1, 2005 through June 30, 2006 | 1 to .75 |
| July 1, 2006 through redemption | 1 to .50 |

(1) For 1,048,336 shares of preferred stock, this date has been extended to one year after the effective date of the registration statement with the SEC.

Additionally, commencing seven years after the date of issuance, holders of the preferred stock may elect to require the Company to redeem their preferred stock at a redemption price equal to the liquidation value of $12 per share, plus accrued but unpaid dividends, if any ("Redemption Price"). Upon the receipt of a redemption election, the Company, at its option, shall either: (1) pay the holder cash in the amount equal to the Redemption Price or (2) issue to holder shares of common stock as defined by the agreement. The Company is accreting the carrying value of its preferred stock to its redemption price using the effective interest method with accretion recorded to additional paid in capital. The accretion of preferred stock results in a reduction of earnings per share applicable to common stockholders.

During 2004, the Board of Directors approved and the Company issued 630,250 stock options to officers and employees of the Company exercisable at $7 per share. The options are exercisable at a price not less than the fair market value of the stock at the date of grant and have an exercisable period of five years. The majority of these options vest over a three year period. During 2004, 60,000 stock options were forfeited as a result of employee terminations.

During 2003, the Board of Directors approved and the Company issued 1,374,553 stock options to officers and employees of the Company exercisable at prices ranging from $4 to $10 per share. The options are exercisable at a price not less than the fair market value of the stock at the date of grant, have an exercisable period of five years and generally are fully vested at the date of grant. During 2003, 648,000 stock options were forfeited as a result of employee terminations.

On September 6, 2001, the Board of Directors approved the issuance of 2,520,613 stock options to officers and employees under certain plans subject to shareholder approval. These plans were approved at the annual shareholder meeting in 2002. As a result, the Company issued and granted a total of 2,505,242 options exercisable at $10 per share. The options are exercisable at a price not less than the fair market value of the stock at the date of grant, have an exercisable period of five years and generally are fully vested at the date of grant. On October 1, 2002, in order to improve the Company's capital structure senior management and other employees voluntarily surrendered to the Company and terminated 2,760,783 stock options that were exercisable at prices ranging from $4 to $10 per share through September 4, 2006.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

A summary of the status of the Company's options issued to employees as of December 31, 2004, 2003 and 2002 and changes during the years ended on those dates is presented below:

| | Incentive Options | Weighted Average Exercise Price |
|---|---|---|
| Options outstanding — December 31, 2001 | 1,770,000 | $ 4.00 |
| Issued | 2,505,242 | $ 10.00 |
| Exercised | — | |
| Expired | — | |
| Forfeited | (2,760,783) | $ 8.74 |
| Options outstanding — December 31, 2002 | 1,514,459 | $ 5.29 |
| Issued | 1,374,553 | $ 4.05 |
| Exercised | — | |
| Expired | — | |
| Forfeited | (648,000) | $ 4.00 |
| Options outstanding — December 31, 2003 | 2,241,012 | $ 5.10 |
| Issued | 630,250 | $ 7.00 |
| Exercised | (186,056) | $ 4.00 |
| Expired | — | |
| Forfeited | (60,000) | $ 4.00 |
| Options outstanding — December 31, 2004 | 2,625,206 | $ 5.66 |

As of December 31, 2003 and 2002, options exercisable were 2,185,762 and 1,171,959, respectively.

The following table summarizes information about the Company's stock options outstanding at December 31, 2004:

| Exercise Price | Options Outstanding at Year End | Weighted Average Remaining Life (In Years) | Options Exercisable at Year End |
|---|---|---|---|
| $4.00 | 1,571,757 | 2.65 | 1,545,007 |
| $7.00 | 655,250 | 4.27 | 330,125 |
| $10.00 | 398,199 | 1.94 | 398,199 |
| Total | 2,625,206 | 2.95 | 2,273,331 |

**NOTE F — INCOME TAXES**

The Company and its subsidiaries file a consolidated income tax return.

The Company's effective income tax rate differed from the federal statutory rate as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Income taxes at federal statutory rate (34%) | $ (3,335,385) | $ (295,767) | $ (2,753,056) |
| Change in valuation allowance | 4,375,484 | 364,836 | 1,812,915 |
| Nondeductible expenses | 45,064 | 46,517 | 55,126 |
| State income taxes at statutory rate | (588,597) | (52,194) | (485,833) |
| Adjustment of estimated income tax provision of prior year | (482,418) | 65,608 | 899,550 |
| Other | (73,148) | — | 298 |
| | $ (59,000) | $ 129,000 | $ (471,000) |

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Deferred tax assets and liabilities are as follows as of December 31:

| | 2004 | 2003 |
|---|---|---|
| Deferred tax assets relating to: | | |
| Net operating loss carryforward | $ 30,617,015 | $ 25,977,793 |
| Other | 314,400 | 314,400 |
| | 30,931,415 | 26,292,193 |
| Less valuation allowance | 28,696,007 | 24,320,523 |
| Total deferred tax assets | 2,235,408 | 1,971,670 |
| Deferred tax liabilities relating to: | | |
| Capitalized intangible assets | 1,190,250 | 887,172 |
| Oil and gas properties and tangible equipment | 184,286 | 570,706 |
| Net unrealized gain on investments | 860,872 | 513,792 |
| Total deferred tax liabilities | 2,235,408 | 1,971,670 |
| Net deferred tax asset | $ — | $ — |

A valuation allowance for deferred tax assets is required when it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of this deferred tax asset depends on the Company’s ability to generate sufficient taxable income in the future. Management believes it is more likely than not that the net deferred tax asset will not be realized by future operating results. The valuation allowance increased $4,375,484, $364,836 and $1,812,915 for the years ended December 31, 2004, 2003 and 2002, respectively.

At December 31, 2004, the Company had net operating loss carryforwards for federal income tax purposes of approximately $76,500,000, which begin to expire in 2012.

**NOTE G — COMMITMENTS AND CONTINGENCIES**

***General Commitments***

The Company has entered into various commitments and operating agreements related to development and production of certain oil and gas properties. It is management’s belief that such commitments, as stated below, will be met without significant adverse impact to the Company’s financial position or results of operations.

The Company has entered into employment agreements with certain key executives. Under the terms of these agreements, the executive is entitled to termination compensation equal to at least two years annual salary if terminated without cause or in the event of a change in control. At December 31, 2004, the maximum termination compensation for all executives is $2,244,000.

***Oil and Gas Partnerships***

The Company is the managing general partner in various oil and gas partnerships. Accordingly, the Company is unconditionally liable for liabilities that may be incurred by such partnerships. The partnerships have no liabilities except accounts payable to the Company for lease operating and administrative expenses.

The Company has a contract with Western Gas related to its Piper Federal lease. The contract is for the sale of a minimum of 2,500 Mcf of gas per day at the wellhead and expires on February 1, 2006. If the Company fails to deliver 2,500 Mcf of gas per day, Western Gas may charge the Company a deficiency fee. The deficiency fee is defined as the amount of deficient Mcf times 90% (amount below 2,500 Mcf times 90%) times the deficiency rate of $0.42 per Mcf representing gathering, compression and transportation charges. The maximum deficiency charge through the period of contract expiration is approximately $375,000. During 2004, 2003 and 2002, there were no deficiency fees due under the contract.

The Company has a transportation contract with Williston Basin Interstate (“WBI”) through October 8, 2006 related to its LX Bar lease. If the Company fails to deliver 6,000 Mcf of gas per day, WBI may charge the Company a transportation fee. The transportation fee is defined as the amount of deficient Mcf times the transportation rate of approximately $0.30 per Mcf. During 2004, 2003 and 2002, the Company paid transportation fees of approximately $185,000, $169,000 and $276,000, respectively. The maximum deficiency charge through the period of contract expiration is approximately $1,160,000.

***Repurchase Agreements***

Under certain repurchase agreements, the investor partners in certain affiliated drilling programs have a right to have their interests repurchased by the Company. Such purchase price is calculated at a formula price and is payable in seven to 25 years from the date of admission to the partnership. For certain affiliated partnerships formed prior to 1998, the maximum purchase price for all such interests was fully secured at maturity by zero coupon U.S. Treasury Bonds held by an independent trust company. The face amounts of such securities are released to the Company when equal amounts of cash distributions are made to investors. As a result of the recapitalizations, any payment made under this guarantee would be treated as a reduction to minority interest as shown on the Company’s balance sheet. At December 31, 2004, the maximum cash outlay relating to these repurchase obligations is approximately $4,356,000. This amount is collateralized by U.S Treasury Bonds with a face value of approximately $1,104,000.

For certain other repurchase agreements relating to partnerships formed from 1998 to 2001, to the extent that the drilling programs and other program investors elect not to purchase a withdrawing partner’s interest, investor partners have a right to have their interests repurchased by the Company at a formula price. This right is effective seven to 25 years from the date of the original partnerships investment. In determining the amount of the repurchase obligation, the obligation is computed based on the lesser of a formula purchase price or the estimated cash flows discounted at 10% (“PV−10”) from proved developed and undeveloped reserves of each partnership. At December 31, 2004, the formula purchase price with respect to these partnerships was approximately $94,400,000. However, this amount is limited to approximately $19,000,000 based on the PV−10 of the assets in these partnerships. This limitation may increase when we drill the remaining 9 net wells or place the remaining 35 net well on production on behalf of these seven drilling programs and will fluctuate due to the variables in determining discounted cash flows, such as price changes and reserve revisions. In the event of repurchase, the Company receives the investor’s interest in the program and the investors pro rata share of the programs reserves and related future cash flows.

***Trust Indenture Agreements***

Under certain Trust Indenture Agreements, the Company has purchased zero coupon U.S. Treasury Bonds to secure repayment of the outstanding principal amount of debentures when due at maturity. At December 31, 2004 and 2003, the face amounts of U.S. Treasury Bonds securing the Company’s obligation under the Trust Indenture Agreements were $23,614,000 and $20,536,000, respectively, and the market values of these U.S. Treasury Bonds were approximately $17,048,360 and $14,023,000, respectively (see Note D).

***Leases***

The Company leases office space in New York City, which expires in March 2008. The Company’s oil and gas administrative office in Casper, Wyoming occupies 3,750 square feet under a lease currently being negotiated. In June 2003, the Company entered into an office lease in Roswell, New Mexico, which expires in May 2005.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

Future minimum annual rental payments, which are subject to escalation and include utility charges as of December 31, 2004, are as follows:

| | |
|---|---|
| Year ending December 31 | |
| 2005 | $ 160,186 |
| 2006 | 155,686 |
| 2007 | 155,686 |
| 2008 | 38,921 |
| | $ 510,479 |

Rent expense under these leases was approximately $166,000, $162,000 and $254,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

***Litigation***

In 1998, Warren Resources, Inc. and Warren E&P, Inc., were sued in the 81st Judicial District Court of Frio County, Texas by Stricker Drilling Company, Inc. and Manning Safety Systems to recover the value of lost equipment based on a well blow−out. As a result of the lawsuit, Gotham Insurance Company, Warren E&P's well blow−out insurer, intervened. The suit was settled in 1999 with all parties except Gotham and other underwriters. Gotham paid more than $1,800,000 under the insurance policy and is now seeking a refund of approximately $1,800,000, denying coverage, and alleging fraud and misrepresentation and a failure of Warren E&P to act with due diligence and pursuant to safety regulations. Warren E&P countersued for the remaining proceeds under the policy coverage. In the summer and fall of 2000, summary judgments were entered in favor of Warren E&P on essentially all claims except its bad faith claims against Gotham, and Gotham's claims were rejected. Final judgment was rendered by the District Court on May 14, 2001 in Warren E&P's favor for the remaining policy proceeds, interest and attorneys' fees. Gotham appealed the final judgment to the San Antonio Court of Appeals, seeking a refund of approximately $1,500,000. On July 23, 2003, the San Antonio Court of Appeals reversed, in Gotham's favor, the trial court's earlier summary judgment for Warren E&P and remanded the case to the trial court for further proceedings consistent with the San Antonio Court of Appeals' decision. A hearing was held on December 17, 2004 to consider the parties' motions to determine both the amount of actual loss incurred by Gotham and the amount of judgment liability to be paid by Warren and Warren E&P. On January 4, 2005, the Company received an order of the trial court that Warren and Warren E&P were obligated to repay Gotham $1,800,000, along with attorneys' fees and statutory interest estimated at $966,000. At December 31, 2004, Warren recorded a provision for $1,800,000 relating to this settlement. On January 31, 2005, Warren filed a Motion for New Trial before the trial court. If our Motion for New Trial is not granted, Warren intends to appeal the order of the trial court to the Texas Court of Appeals. Although management and counsel believe that the Company has meritorious grounds for the appeal, if the appeal is unsuccessful, the Company will pay the restitution to Gotham as ordered by the trail court.

The Company is a party to various other matters of litigation arising in the normal course of business (see Note I). Management believes that the ultimate outcome of the matters will not have a material effect on the Company's financial condition or results of operations.

**NOTE H — EMPLOYEE BENEFIT PLANS**

The Company has a retirement plan covering substantially all qualified corporate employees under section 401(k) of the Internal Revenue Code. The Company contributed for each participant a required matching contribution equal to 50% of the participant's contribution to a maximum of 6% of each employee's annual compensation. The Company may also make discretionary contributions. The Company's expenses under the plan were approximately $64,000, $66,000 and $78,000 for the years ended December 31, 2004, 2003 and 2002, respectively.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

***Affiliated Partnerships***

The Company contributed mineral rights with an agreed−upon fair value of $142,247 and $184,916 during 2003 and 2002, respectively, to affiliated partnerships in exchange for a 10% interest in these partnerships. The mineral rights remain at cost in the Company's property accounts. Affiliated partnerships paid $6,077,150 and $5,163,250 to the Company during 2003 and 2002, respectively, under fixed price turnkey drilling contracts. At December 31, 2004 and 2003, accounts receivable from affiliated partnerships were approximately $143,000 and $389,000, respectively, relating primarily to administrative costs paid by the Company on behalf of the partnerships.

During the third quarter of 2003, certain joint venture general partnerships formed between accredited investors and Warren Resources, Inc. commenced a vote to (a) amend their joint venture agreement to allow for two classes of partners: preferred partners and common partners and (b) allow partners to select whether they wanted to be preferred partners having certain preferred rights in the joint venture by consenting to the additional capital contributed by the Company in the form of its unregistered preferred shares. For its additional capital contribution, Warren received additional common partner interests in the joint venture. During the fourth quarter of 2003, the joint ventures received the necessary 50% of affirmative votes required to effect the transaction. As a result, the Company issued approximately 1,048,000 preferred shares with an estimated value of $12,576,000 to the joint ventures as consideration for the joint ventures working interest in certain unproved acreage in Wyoming. Additionally, approximately $4,604,000 of deferred income was eliminated as a result of the transaction and was recorded as a reduction in the property basis.

***Joint Venture Agreements***

Warren E&P, Inc. is party to separate joint venture agreements with the affiliated partnerships. The agreements form a joint venture between Warren E&P and each partnership for the purpose of participating in the drilling and re−completion of oil and gas wells. Under the terms of the agreements, property acquisition and capital equipment costs are borne by Warren E&P. Generally, intangible drilling and development costs are borne by the partnerships.

Under the terms of the joint venture agreement, the affiliated partnerships have an initial 75% interest in the aggregate net profits of the properties. Once the partners have received distributions equal to the partner's investment, Warren E&P will receive an additional reversionary interest of 15% and the partnerships' interest will be reduced to 60%.

The partnerships are parties to a standard form of operating agreement with Warren E&P (the "Operator") pursuant to which the Operator will be responsible for the operation of the wells. Also, the Operator is engaged to supervise all drilling and recompletion of wells, on behalf of all working interests, and has full control of all operations of the wells as covered under the Operating Agreement. Each partnership pays the Operator its pro rata share of monthly operating expenses.

In May 1999, the Company entered into an agreement with Magness Petroleum Company ("Magness") to form a joint venture for the purpose of participating in the horizontal drilling and re−completing of existing oil wells and the drilling of new oil wells within the Wilmington Oil Field in Los Angeles County, California. On February 2, 2005, Warren closed the acquisition of all rights, titles and interests in the Wilmington Oil Field in Los Angeles County from Magness, for a price of approximately $14,800,000 in cash. The acquisition is effective as of January 1, 2005. Additionally, effective February 1, 2005, Warren's wholly owned operating subsidiary, Warren E&P, Inc., was elected operator of the Wilmington Unit.

***Other Income***

In December 2002, the Company's Executive Vice President died in an accident. The Company carried life insurance in the amount of approximately $3,750,000 on this officer. At December 31, 2002, a receivable for these insurance proceeds, which was collected in February 2003, was recorded and income of approximately $3,750,000 was recognized in interest and other income on the consolidated statement of operations.

**NOTE J — RECAPITALIZATION OFFERS**

During the fourth quarter of 2002, the Company, acting as the MGP, commenced a vote solicitation of the limited partners of the certain partnerships (the “Partnership Recapitalization Offers”) to: (1) obtain the requisite two−thirds affirmative vote of their respective partners to convert the drilling program from a Delaware limited partnership into a Delaware limited liability company (the “LLC”) wherein all LLC members would have limited liability, including the Company, and (ii) upon conversion to an LLC, the Company would contribute as additional capital to the LLC its unregistered 8% convertible preferred stock with a value equal to between 110% to 120% of the potential repurchase price of consenting members’ interests (“Preferred Members”) calculated as of December 31, 2002. The Company would receive additional standard membership interests in the LLC and be specially allocated, pro rata as a standard member, the Preferred Members’ interests in the oil and gas properties owned by their respective programs (the “Recapitalization”). Acceptance by Preferred Members of the Recapitalization terminated their repurchase rights under the original buy/sell agreements. At December 31, 2002, six of the thirteen programs obtained the requisite votes to convert to LLCs and because of the majority control by the Company were consolidated in the financial statements for the year ended December 31, 2002. As a result, the Company issued 1,342,960 preferred shares to these six LLCs in 2002 with an estimated fair value of $16,115,520. At March 31, 2003, the remaining seven programs obtained the requisite votes to convert to LLCs and on average 72.9% of the program members elected to become Preferred Members in their LLC. During the first quarter of 2003, the Company issued 1,641,628 preferred shares to the remaining seven LLCs as a capital contribution, with an estimated fair value of $19,699,536 and received its prorata share of additional standard membership interests in the LLCs. The fair value of the preferred shares was based on actual cash sales to independent parties in this time period. Due to the majority control of these thirteen affiliated partnerships, the Company has consolidated these entities for financial reporting purposes at December 31, 2004. The Company accounted for these acquisitions as purchase transactions with the estimated fair value of assets acquired and liabilities assumed in the acquisition as follows:

| | 2003 | 2002 |
|---|---|---|
| Estimated fair value of assets acquired | | |
| Current assets | $ 3,512 | $ 4,350 |
| Oil and gas properties | 28,342,950 | 25,252,358 |
| Total fair value of assets | 28,346,462 | 25,256,708 |
| Liabilities assumed | | |
| Accounts payable | 144,122 | 171,110 |
| Minority interest | 8,502,804 | 8,970,078 |
| Total liabilities assumed | 8,646,926 | 9,141,188 |
| Cost of acquisition | $ 19,699,536 | $ 16,115,520 |

Subsequent to the recapitalization offers that closed on March 31, 2003, and December 31, 2002, certain minority interest limited partners elected to convert to preferred members, which resulted in the Company issuing 356,971 preferred shares to these individuals with an estimated fair value of $4,283,652.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The following summarizes pro forma unaudited results of operations for the years ended December 31, 2003 and 2002, as if these acquisitions had been consummated immediately prior to January 1, 2002. These pro forma results are not necessarily indicative of future results.

| | Pro Forma (Unaudited) Year Ended December 31, | |
|---|---|---|
| | 2003 | 2002 |
| Revenues | $ 26,531,361 | $ 33,960,704 |
| Net loss | $ (658,131) | $ (10,333,144) |
| Loss per share, basic and diluted | $ (0.31) | $ (0.60) |

The operations of the affiliated partnerships are included in the Company's results of operations subsequent to December 31, 2002, for the 2002 acquisition and subsequent to March 31, 2003, for the 2003 acquisition.

**NOTE K — FAIR VALUE OF FINANCIAL INSTRUMENTS**

The following methods and assumptions were used to estimate the fair value of each class of financial instruments and do not purport to represent the aggregate net fair value of the Company.

*Cash and Cash Equivalents.* The balance sheet carrying amounts of cash and cash equivalents approximate fair values of such assets.

*U.S Treasury Bonds — Trading Securities and Available−For−Sale.* The fair values are based upon quoted market prices for those or similar investments.

*Convertible Debentures.* Fair values of fixed rate convertible debentures were calculated using interest rates in effect as of year end for similar instruments with the other terms unchanged.

*Other Long−Term Liabilities.* The carrying amount approximates fair value due the current rates offered to the Company for long−term liabilities of the same remaining maturities.

| | 2004 | | 2003 | |
|---|---|---|---|---|
| | Fair Value | Carrying Amount | Fair Value | Carrying Amount |
| Financial assets | | | | |
| Cash and cash equivalents | $ 99,920,885 | $ 99,920,885 | $ 24,528,999 | $ 24,528,999 |
| U.S. Treasury bonds and other investments — trading securities | 174,247 | 174,247 | 201,152 | 201,152 |
| U.S. Treasury bonds — available−for−sale | 18,162,053 | 18,162,053 | 15,211,135 | 15,211,135 |
| Financial liabilities | | | | |
| Fixed rate debentures | $ (49,460,549) | $ (46,476,700) | $ (53,169,798) | $ (48,094,700) |
| Other long−term liabilities | (1,738,168) | (1,738,168) | (1,821,464) | (1,821,464) |

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**NOTE L — OIL AND GAS INFORMATION**

Costs related to the oil and gas activities of the Company were incurred as follows for the years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Property acquisition — unproved | $ 3,046,654 | $ 9,967,002 | $ 176,030 |
| Property acquisition — proved | 4,495,283 | 28,389,424 | 25,419,962 |
| Exploration costs | 902,564 | 525,098 | 471,948 |
| Development costs | 18,648,722 | 10,425,296 | 3,888,221 |
| | $ 27,093,223 | $ 49,306,820 | $ 29,956,161 |

Asset retirement costs of approximately $8,000 and $307,000 are included in proved property acquisition costs for 2004 and 2003.

During the years ended December 31, 2004, 2003 and 2002, exploration costs of approximately $143,000, $92,000 and $472,000, respectively, were expensed.

The Company had the following aggregate capitalized costs relating to the Company's oil and gas activities at December 31:

| | 2004 | 2003 |
|---|---|---|
| Unproved oil and gas properties | $ 71,029,835 | $ 50,738,040 |
| Proved oil and gas properties | 108,618,748 | 103,423,818 |
| | 179,648,583 | 154,161,858 |
| Less accumulated depreciation, depletion amortization and impairment | 63,053,277 | 59,212,313 |
| | $ 116,595,306 | $ 94,949,545 |

The following table sets forth the Company's results of operations from oil and natural gas producing activities for the years ended December 31:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Revenues | $ 6,454,334 | $ 5,717,814 | $ 592,528 |
| Production costs | (3,792,002) | (3,719,780) | (294,520) |
| Exploration costs | (143,135) | (91,815) | (471,948) |
| Accretion of asset retirement obligation | (52,711) | (62,452) | — |
| Depreciation, depletion, amortization and impairment | (3,840,781) | (3,102,354) | (9,606,606) |
| Loss from oil and gas producing activities | $ (1,374,295) | $ (1,258,587) | $ (9,780,546) |

In the presentation above, no deduction has been made for indirect costs such as corporate overhead or interest expense. No income taxes are reflected above due to the Company's tax loss carryforwards.

Depreciation, depletion, amortization and impairment expense was $3,840,781, $3,102,354 and $9,606,606 or $3.13, $2.37 and $120 per equivalent Mcf of production for the years ended December 31, 2004, 2003 and 2002, respectively. These amounts include impairment expenses, primarily for unproved properties of $2,279,828, $1,899,705 and $9,299,981 for the years ended December 31, 2004, 2003 and 2002, respectively.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

**NOTE M — OIL AND GAS RESERVE DATA (UNAUDITED)**

The following estimates of proved reserve quantities and related standardized measure of discounted net cash flows 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.

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 operating methods.

The standardized measure of discounted future net cash flows is computed by applying year−end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) 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, with consideration of future tax rates already legislated) 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% per year to reflect the estimated timing of the future cash flows.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves developed by Williamson Petroleum Consultants, Inc., our independent petroleum engineers.

**Summary of Changes in Proved Reserves**

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2004 | | 2003 | | 2002 | |
| | Mbbls | Mmcf | Mbbls | Mmcf | Mbbls | Mmcf |
| Proved reserves | | | | | | |
| Beginning of year | 15,124 | 15,448 | 12,324 | 8,502 | 8,478 | 2,495 |
| Purchase of reserves in place | — | — | 2,688 | 4,218 | 3,538 | 1,770 |
| Discoveries and extensions | 39 | 3,632 | — | 6,291 | — | 5,294 |
| Revisions of previous estimates | (918) | 279 | 199 | (2,778) | 312 | (1,002) |
| Production | (68) | (817) | (87) | (785) | (4) | (55) |
| End of year | 14,177(1) | 18,542(1) | 15,124(2) | 15,448(2) | 12,324(3) | 8,502(3) |
| Proved developed reserves | | | | | | |
| Beginning of year | 476 | 7,006 | 404 | 4,544 | 8 | 1,648 |
| End of year | 395 | 8,496 | 476 | 7,006 | 404 | 4,544 |

(1) Included in 2004 reserves, 2,142 Mbbls and 357 Mmcf is attributable to consolidated subsidiaries in which there is an average 23% minority interest.

(2) Included in 2003 reserves, 2,469 Mbbls and 1,028 Mmcf is attributable to consolidated subsidiaries in which there is an average 25% minority interest.

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

(3) Included in 2002 reserves, 1,195 Mbbls and 577 Mmcf is attributable to consolidated subsidiaries in which there is an average 34% minority interest

**Standardized Measure of Discounted Future Net Cash Flows**
**Relating to Proved Oil and Gas Reserves**

| | December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (Amounts in thousands) | | |
| Future cash inflows | $ 631,190 | $ 499,693 | $ 362,982 |
| Future production costs and taxes | (106,363) | (69,180) | (47,661) |
| Future development costs | (59,541) | (60,272) | (43,003) |
| Future income tax expenses | (110,161) | (87,042) | (110,939) |
| Net future cash flows | 355,125 | 283,199 | 161,379 |
| Discounted at 10% for estimated timing of cash flows | (162,480) | (137,073) | (89,961) |
| Standardized measure of discounted future net cash flows | $ 192,645(1) | $ 146,126(2) | $ 71,418(3) |

(1) Included in 2004 reserves, $26,054 is attributable to consolidated subsidiaries in which there is an average 23% minority interest.

(2) Included in 2003 reserves, $23,017 is attributable to consolidated subsidiaries in which there is an average 25% minority interest.

(3) Included in 2002 reserves, $10,462 is attributable to consolidated subsidiaries in which there is an average 34% minority interest.

**Changes in Standardized Measure of Discounted Future Net Cash Flows**
**Related to Proved Oil and Gas Reserves**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2004 | 2003 | 2002 |
| | (Amounts in thousands) | | |
| Sales, net of production costs and taxes | $ (2,519) | $ (1,934) | $ (298) |
| Discoveries and extensions | 5,967 | 9,339 | 5,550 |
| Purchases of reserves in place | — | 30,875 | 30,944 |
| Changes in prices and production costs | 55,595 | 7,624 | 46,531 |
| Revisions of quantity estimates | (14,249) | (2,882) | 1,884 |
| Net changes in development costs | (34) | (13,341) | (1,048) |
| Interest factor — accretion of discount | 18,299 | 11,396 | 2,047 |
| Net change in income taxes | (12,788) | 5,677 | (41,566) |
| Changes in production rates (timing) and other | (3,752) | 27,954 | 7,862 |
| Net increase | 46,519 | 74,708 | 51,906 |
| Balance at beginning of year | 146,126 | 71,418 | 19,512 |
| Balance at end of year | $ 192,645 | $ 146,126 | $ 71,418 |

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using current sales prices, along with estimates of the operating costs, production taxes and future development and abandonment costs (less salvage value) necessary to produce such reserves. The average prices used at December 31, 2004, 2003 and 2002 were $37.59, $28.45 and $27.15 per Bbl and $5.30,

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

$4.50 and $3.36 per Mcf, respectively. No deduction has been made for depreciation, depletion or any indirect costs such as general corporate overhead or interest expense.

Operating costs and production taxes are estimated based on current costs with respect to producing oil and natural gas properties. Future development costs are based on the best estimate of such costs assuming current economic and operating conditions. The future cash flows estimated to be spent to develop the Company’s portion of proved undeveloped properties in the years ended December 31, 2005, 2006 and 2007 are $21,037,639, $28,071,598 and $10,431,386, respectively.

Income tax expense is computed based on applying the appropriate statutory tax rate to the excess of future cash inflows less future production and development costs over the current tax basis of the properties involved, less applicable carryforwards, for both regular and alternative minimum tax.

The future net revenue information assumes no escalation of costs or prices, except for oil and natural gas sales made under terms of contracts which include fixed and determinable escalation. Future costs and prices could significantly vary from current amounts and, accordingly, revisions in the future could be significant.

**NOTE N — QUARTERLY INFORMATION (UNAUDITED)**

Summarized quarterly financial data for the years ended December 31, 2004 and 2003 are as follows:

| | 2004 | | | | |
|---|---|---|---|---|---|
| | Quarter | | | | |
| | First | Second | Third | Fourth | Year |
| Revenues | $ 4,332,302 | $ 6,030,246 | $ 8,137,770 | $ 7,891,512 | $ 26,391,830 |
| Gross profit | (142,365) | 1,005,638 | (195,276) | (11,359) | 656,638 |
| Net loss | (1,058,866) | (1,259,315) | (1,873,768) | (5,768,349) | (9,960,298) |
| Loss per share | | | | | |
| Basic and diluted | $ (0.15) | $ (0.15) | $ (0.18) | $ (0.33) | $ (0.84) |

| | 2003 | | | | |
|---|---|---|---|---|---|
| | Quarter | | | | |
| | First | Second | Third | Fourth | Year |
| Revenues | $ 4,437,681 | $ 4,441,003 | $ 6,173,532 | $ 10,610,647 | $ 25,662,863 |
| Gross profit | 634,381 | 1,117,818 | 1,383,088 | 3,412,457 | 6,547,744 |
| Net income (loss) | (1,234,322) | (13,782) | 664,966 | (616,245) | (1,199,383) |
| Loss per share | | | | | |
| Basic and diluted | $ (0.12) | $ (0.06) | $ (0.02) | $ (0.14) | $ (0.34) |

Quarterly and year−to−date computations of per share amounts are made independently. Therefore, the sum of quarterly per share amounts may not agree with per share amounts for the year.

During the fourth quarter of 2004, the Company had the following significant adjustments:

- Recorded a contingent liability for $1,800,000 relating to the Gotham litigation (see Note G).
- Recognized impairment on oil and gas properties of approximately $1,000,000, as a result of the expiration of certain unproved Washakie leases and net capitalized costs exceeding the expected future net cash flow based on engineering estimates on certain properties (see Note L).

The effect of these adjustments were to increase the net loss by approximately $2,800,000 or $(.12) and $(.14) per basic and diluted share for the quarter and year ended December 31, 2004, respectively.

During the fourth quarter of 2003, the Company had the following significant adjustment:

- Recognized impairment on oil and gas properties of approximately $1,900,000 as a result of the expiration of certain unproved Washakie leases and net capitalized costs exceeding the expected future net cash flow based on engineering estimates on certain properties (see Note L).

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

The effect of this adjustment was to increase the net loss by approximately $1,900,000 or $(.11) per basic and diluted share for the quarter and year ended December 31, 2003.

**NOTE O — SEGMENT INFORMATION**

The Company's operating activities can be divided into four major segments: turnkey contracts, oil and gas marketing, oil and gas exploration and production operations and well services. The Company drills oil and natural gas wells for Company−sponsored drilling partnerships and retains an interest in each well. The Company also markets natural gas for affiliated partnerships. The Company charges Company−sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. Segment information for the years ended December 31 is as follows:

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Revenues from external customers | | | |
| Turnkey contracts | $ 10,529,883 | $ 11,300,646 | $ 5,841,110 |
| Oil and gas marketing | 6,171,338 | 5,620,522 | 11,272,398 |
| Oil and gas operations | 6,574,527 | 6,212,311 | 4,879,302 |
| Well services | 1,070,004 | 1,167,564 | 1,895,453 |
| Other | 2,046,078 | 1,361,820 | 5,722,027 |
| Total | $ 26,391,830 | $ 25,662,863 | $ 29,610,290 |
| Intersegment revenue | | | |
| Well services | $ — | $ — | $ — |
| Other | — | — | 25,660 |
| Total | $ — | $ — | $ 25,660 |
| Interest and other income | | | |
| Turnkey contracts | $ 258 | $ 4,246 | $ 3,368 |
| Oil and gas marketing | — | — | — |
| Oil and gas operations | 1,996 | 6,586 | 31,439 |
| Well services | — | — | 2,540 |
| Other | 2,086,740 | 1,329,227 | 5,246,155 |
| Intersegment elimination | — | — | (25,660) |
| Total | $ 2,088,994 | $ 1,340,059 | $ 5,257,842 |

**Warren Resources, Inc. and Subsidiaries**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)**

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Consolidated revenues | | | |
| Total segment revenue | $ 24,345,752 | $ 24,301,043 | $ 23,888,263 |
| Other | 2,046,078 | 1,361,820 | 5,747,687 |
| Intersegment elimination | — | — | (25,660) |
| Total | $ 26,391,830 | $ 25,662,863 | $ 29,610,290 |
| Interest expense | | | |
| Turnkey contracts | $ 735 | $ 9,200 | $ 5,577 |
| Oil and gas marketing | — | — | — |
| Oil and gas operations | 52,771 | 62,452 | |
| Well services | — | — | 28,957 |
| Other | 440,471 | 1,456,417 | 6,303,757 |
| Elimination of intersegment | — | — | (25,660) |
| Total | $ 493,977 | $ 1,528,069 | $ 6,312,631 |
| Depreciation, depletion, amortization and impairment | | | |
| Turnkey contracts | $ 103,216 | $ 102,534 | $ 102,942 |
| Oil and gas marketing | — | — | — |
| Oil and gas operations | 3,840,781 | 3,102,354 | 9,606,606 |
| Well services | — | — | 47,643 |
| Other | 78,728 | 44,972 | 172,971 |
| Total | $ 4,022,725 | $ 3,249,860 | $ 9,930,162 |
| Operating income (loss) | | | |
| Turnkey contracts | $ (2,505,934) | $ 3,908,505 | $ 3,835,194 |
| Oil and gas marketing | 142,611 | 120,096 | 150,876 |
| Oil and gas operations | (1,252,166) | (757,504) | (6,021,629) |
| Well services | 397,071 | 505,436 | 982,515 |
| Other | (6,591,539) | (4,646,435) | (7,044,180) |
| Total | $ (9,809,957) | $ (869,902) | $ (8,097,224) |

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Assets | | | |
| Turnkey contracts | $ 13,022,081 | $ 23,625,826 | $ 34,982,047 |
| Oil and gas marketing | 192,642 | 192,642 | 192,642 |
| Oil and gas operations | 121,069,107 | 106,113,628 | 54,582,576 |
| Well services | — | — | 94,338 |
| Other | 112,626,831 | 21,121,567 | 18,410,691 |
| Total | $ 246,910,661 | $ 151,053,663 | $ 108,262,294 |
| Capital expenditures | | | |
| Turnkey contracts | $ — | $ — | $ — |
| Oil and gas marketing | — | — | — |
| Oil and gas operations | 27,102,948 | 12,735,327 | 4,744,732 |
| Well services | — | — | — |
| Other | | 4,221 | 5,313 |
| Total | $ 27,102,948 | $ 12,739,548 | $ 4,750,045 |

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## INDEX TO EXHIBITS

| Exhibit No. | Description |
|---|---|
| 2.1(1) | Stock Exchange Agreement, dated September 1, 2000, by and among the Registrant, Petroleum Development Corporation, James C. Johnson, Jr. and Gregory S. Johnson. |
| 3.1† | Articles of Incorporation of Registrant filed May 20, 2004 (Maryland) |
| 3.2(10) | Bylaws of the Registrant, dated June 2, 2004 |
| 3.3(10) | Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland) |
| 3.4(10) | Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland) |
| 3.5(10) | Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland) |
| 3.6(10) | Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland) |
| 4.1† | Specimen Stock Certificate for Common Stock |
| 4.2(1) | Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated December 1, 2000 regarding 12% debentures due December 31, 2007 |
| 4.3(1) | Form of Bond Certificate for 12% debentures due December 31, 2007 |
| 4.4(1) | Indenture between the Registrant and Continental Stock Transfer and Trust Company, as Trustee, dated February 1, 1999 regarding 13.02% debentures due December 31, 2010 and December 31, 2015 |
| 4.5(1) | Form of Bond Certificate for 13.02% debentures due December 31, 2010 |
| 4.6(1) | Form of Bond Certificate for 13.02% debentures due December 31, 2015 |
| 4.7(8) | Form of Class A Common Stock Warrant |
| 4.8(8) | Form of Class B Common Stock Warrant |
| 4.9(3) | Form of Registration Rights Agreement made as of December 12, 2002, by and between Warren Resources the Investors in the Series A 8% Cumulative Convertible Preferred Stock. |
| 4.10(6) | Form of Subscription and Registration Rights Agreement dated February 3, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated January 21, 2004 |
| 4.11(10) | Form of Subscription and Registration Rights Agreement dated July 30, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated July 9, 2004 |
| 4.12(5) | Form of Contribution Agreement by and between Warren Resources, Inc., and various Delaware limited liability companies. |
| 10.1(1) | 2000 Equity Incentive Plan for Warren E&P Subsidiary |
| 10.2(1) | Amendment to 2000 Stock Incentive Plan for Warren E&P Subsidiary |
| 10.3(1) | 2001 Stock Incentive Plan |
| 10.4(1) | 2001 Key Employee Stock Incentive Plan |
| 10.5(1) | Employment Agreement dated January 1, 2001, between the Registrant and Norman F. Swanton |
| 10.6(1) | Employment Agreement dated January 1, 2001, between the Registrant and Timothy A. Larkin |

| | |
|---|---|
| 10.7(9) | Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Norman F. Swanton |
| 10.8(9) | Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin |
| 10.9(9) | Employment Agreement dated March 1, 2004, between the Registrant and Lloyd Davies |
| 10.10(9) | Employment Agreement dated January 1, 2004, between the Registrant and David E. Fleming |
| 10.11(10) | Employment Agreement dated January 1, 2004, between the Registrant and Ellis G. Vickers |
| 10.12(1) | Form of Indemnification Agreement |
| 10.13(1) | Joint Venture Agreement dated May 24, 1999, by and between Warren Resources of California, Inc., Warren Development Corp., Warren E&P and Magness Petroleum Company |

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| Exhibit No. | Description |
|---|---|
| 10.15(1) | Gas Purchase Agreement dated January 28, 2000, by and between Western Gas Resources, Inc. and Big Basin Petroleum, LLC |
| 10.16(1) | December 20, 2000 Letter of Agreement to Amend the Gas Purchase Contract dated January 28, 2000, between Western Gas Resources Inc. and Petroleum Development Corp., as successor in interest to Big Basin Petroleum, LLC |
| 10.17(1) | Gas Purchase and Sales Contract dated April 1, 2000, between the Registrant and Tenaska Marketing Ventures |
| 10.18(1) | Form of Partnership Production Marketing Agreement |
| 10.19(4) | Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc. |
| 10.20(4) | Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P |
| | Company LP, and Anadarko Land Corp. |
| 10.21(4) | Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc. |
| 10.22(11) | Purchase and Sale Agreement dated November 24, 2004 by and among Warren Resources of California, Inc., Magness Petroleum Company and Next Generation Investments, LLC. |
| 10.23(11) | Settlement Agreement and Release dated November 24, 2004 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc., Warren Development Corp. and Magness Petroleum Company. |
| 11† | Statements regarding Computation of Per Share Earnings (Included in the Financial Statement in Part 4) |
| 14(7) | Code of Ethics for Senior Financial Officers |
| 21.1(12) | Subsidiaries of the Registrant |
| 23.1† | Consent of Williamson Petroleum Consultants, Inc. |
| 23.2† | Consent of CBIZ Valuation Group, LLC |
| 31.1† | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 |
| 31.2† | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes−Oxley Act of 2002. |
| 32† | Section 1350 Certification |

(1) Incorporated by reference to the Company’s Registration Statement on Form 10, Commission File No. 000−33275, filed on October 26, 2001.

(2) Incorporated by reference to the Company’s Amendment No. 1 to Registration Statement on Form 10/ A, Commission File No. 000−33275, filed on March 6, 2002.

(3) Incorporated by reference to the Company’s Current Report on Form 8−K filed on December 12, 2002.

(4) Incorporated by reference to the Company’s Current Report on Form 8−K filed on December 24, 2002.

(5) Incorporated by reference to the Company’s Quarterly Report on Form 10−Q for the quarter ended June 30, 2003.

(6) Incorporated by reference to the Company’s Current Report on Form 8−K, Commission File No. 000−33275, filed on February 11, 2004.

(7) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2002, filed on March 31, 2003.

(8) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2003, filed on March 15, 2004.

(9) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended March 31, 2004, filed May 12, 2004.

(10) Incorporated by reference to the Company's Quarterly Report on Form 10−Q for the quarter ended June 30, 2004, filed on August 13, 2003.

(11) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed November 30, 2004.

(12) Incorporated by reference to the Company's Registration Statement on From S−1/ A, Commission File No. 333−118535, filed December 2, 2004.

† Filed herewith.

**Exhibit 3.1**

# ARTICLES OF INCORPORATION

# OF

# WARREN RESOURCES, INC.

The undersigned, JoEllen L. Legg, whose address is 1660 Lincoln Street, Denver, Colorado 80264, being at least 18 years of age, acting as incorporator, does hereby form a corporation under the general laws of the State of Maryland having the following Articles:

## ARTICLE I
## NAME

The name of the corporation (the "Corporation") is: Warren Resources, Inc.

## ARTICLE II
## PURPOSE

The purposes for which the Corporation is formed are to engage in any lawful act or activity for which a corporation may be organized under the General Corporation Law of the State of Maryland (the "Maryland Code"). In furtherance of the foregoing purposes, the Corporation shall have and may exercise all of the rights, powers and privileges granted by the Maryland Code. In addition, the Corporation may do everything necessary, suitable and proper for the accomplishment of any of its corporate purposes.

## ARTICLE III
## PRINCIPAL OFFICE IN STATE AND RESIDENT AGENT

The street address of the principal office and registered agent of the Corporation in the State of Maryland is 11 East Chase Street, Baltimore, Maryland 21202. The name of the resident agent of the Corporation in the State of Maryland at that address is National Registered Agents, Inc. of MD.

## ARTICLE IV
## STOCK

Section 5.1 *Authorized Shares.* The Corporation is authorized to issue a total of 110,000,000 shares of stock in two classes designated respectively "Preferred Stock" and "Common Stock". The total number of shares of all series of Preferred Stock that the Corporation shall have the authority to issue is 10,000,000 and the total number of shares of Common Stock that the Corporation shall have the authority to issue is 100,000,000. All of the authorized shares shall have a par value of $0.0001 per share. The aggregate par value of all authorized shares of stock having par value is $11,000. If shares of one



class of stock are classified or reclassified into shares of another class of stock pursuant to this Article IV, the number of authorized shares of the former class shall be automatically decreased and the number of shares of the latter class shall be automatically increased, in each case by the number of shares so classified or reclassified, so that the aggregate number of shares of stock of all classes that the Corporation has authority to issue shall not be more than the total number of shares of stock set forth in the first sentence of this paragraph. The Board of Directors, without any action by the stockholders of the Corporation, may amend these Articles of Incorporation to change the name or other designation or the par value of any class or series of stock and the aggregate par value of that stock.

Section 5.2 *Common Stock.* Each stockholder of record shall have one vote for each share of common stock standing in his or her name on the books of the Corporation and entitled to vote, except that in the election of directors, each stockholder shall have as many votes for each share held by him or her as there are directors to be elected and for whose election the stockholder has a right to vote. Cumulative voting shall not be permitted in the election of directors or otherwise.

Section 5.3 *Preferred Stock.* Preferred stock may be issued from time to time in one or more series, each of such series to have such designations, relative rights and limitations as may be fixed in the resolution or resolutions providing for the issue of such series adopted by the board of directors of the Corporation as hereinafter provided. Any shares of preferred stock which may be redeemed, purchased or acquired by the Corporation may be reissued except as otherwise provided herein or by law. Different series of preferred stock shall not be construed to constitute different classes of shares for the purposes of voting by classes unless expressly provided for in the resolutions creating such series or required by applicable law. Authority is hereby expressly granted to the Board of Directors from time to time to issue the preferred stock in one or more series, and in connection with the creation of any such series, by resolution or resolutions providing for the issuance of the shares thereof, to determine and fix such voting powers, full or limited, or no voting powers, and such designations, preferences and relative participating, optional or other special rights, and qualifications, limitations or restrictions thereof including, without limitation, dividend rights, conversion rights, redemption privileges and liquidation preferences, as shall be stated and expressed in such resolutions, all to the fullest extent now or hereafter permitted by the Maryland Code. Without limiting the generality of the foregoing, the resolutions providing for issuance of any series of preferred stock may provide that such series shall be superior or rank equally or be junior to the preferred stock of any other series to the extent permitted by law.

**ARTICLE V**
**PERPETUAL EXISTENCE**

The Corporation is to have perpetual existence.

## ARTICLE VI
## INITIAL DIRECTORS

The following persons are elected to serve as the Corporation's initial directors until the next annual meeting of stockholders or until their successors are duly elected and qualify:

| Name | Address |
| --- | --- |
| Norman F. Swanton | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Dominick D'Alleva | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Chet Borgida | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Anthony L. Coelho | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Lloyd G. Davies | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Marshall Miller | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Thomas G. Noonan | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |
| Michael R. Quinlan | 489 Fifth Avenue, 32nd Floor, New York, NY 10017 |

## ARTICLE VII
## DIRECTOR MATTERS

7.1 *Number*. The number of directors shall be fixed from time to time exclusively by the Board of Directors pursuant to a resolution adopted by a majority of the total number of directors (whether or not there exist any vacancies in directorships at the time any such resolution is presented to the board of directors for adoption). The directors of the Corporation need not be elected by written ballot unless the Bylaws so provide.

7.2 *Classification.* On and after the closing date of the first sale of the Corporation's common stock pursuant to an underwritten registered public offering (an "IPO"), the directors shall be divided into three classes with the term of office of the first class (Class I) to expire at the first annual meeting of the stockholders following an IPO; the term of office of the second class (Class II) to expire at the second annual meeting of stockholders held following an IPO; the term of office of the third class (Class III) to expire at the third annual meeting of stockholders following an IPO; and thereafter for each such term to expire at each third succeeding annual meeting of stockholders after such election. All directors shall hold office until the annual meeting of stockholders for the year in which their term expires and until their successors are duly elected and qualified, or until their earlier death, resignation or removal.

7.3 *New Directorships; Vacancies.* Subject to the rights of the holders of any series of preferred stock then outstanding, newly created directorships resulting from any increase in the authorized number of directors or any vacancies in the board of directors resulting from death, resignation or other cause may be filled only by the Board of Directors (unless there are no remaining directors) acting by a majority vote of the directors then in office, though less than a quorum, and directors so chosen shall hold office for a term expiring at the next annual meeting of stockholders at which the term of office of the class to which they have been elected expires, and until their respective successors are elected, or until their earlier death, resignation, or removal. No decrease in the number of directors constituting the board of directors shall shorten the term of any incumbent director.

7.4 *Removal.* Following an IPO, any director, or the entire board of directors, may be removed from office at any time, but only for cause and only by the affirmative vote of the holders of at least 66 2/3% of the voting power of all of the shares of capital stock of the Corporation then entitled to vote generally in the election of directors, voting together as a single class. For purposes hereof, “cause” shall mean gross neglect or willful misconduct in the performance of the duties as a director.

7.5 *Amendments.* The Board of Directors is expressly empowered to adopt, amend or repeal the Bylaws of the Corporation. Any adoption, amendment or repeal of Bylaws of the Corporation by the Board of Directors shall require the approval of a majority of the total number of directors (whether or not there exist any vacancies at the time any resolution providing for adoption, amendment or repeal is presented to the board of directors). The stockholders shall also have power to adopt, amend or repeal the Bylaws of the Corporation. Following an IPO, any adoption, amendment or repeal of Bylaws of the Corporation by the stockholders shall require, in addition to any vote of the holders of any class or series of stock of the Corporation required by law or by these Articles of Incorporation, the affirmative vote of the holders of at least 66 2/3% of the voting power of all of the then outstanding shares of the capital stock of the Corporation entitled to vote generally in the election of directors, voting together as a single class.

## ARTICLE VIII
## STOCKHOLDER ACTIONS

The following provisions are inserted for the management of the business and the conduct of the affairs of the Corporation, and for further definition, limitation and regulation of the powers of the Corporation and of its directors and stockholders:

8.1 *Calling Special Meetings.* Following an IPO, special meetings of stockholders of the Corporation may be called only by (1) the Board of Directors pursuant to a resolution adopted by a majority of the entire Board of Directors, either upon motion or upon written request by the holders of at least 66 2/3% of the voting power of all the shares of capital stock of the Corporation then entitled to vote generally in the election of directors, voting together as a single class or (2) the president of the Corporation.

## ARTICLE IX
## LIMITATION OF LIABILITY

The personal liability of each director and officer of the Corporation shall be eliminated and limited to the full extent permitted by the laws of the State of Maryland, including without limitation as permitted by the provisions of Section 2−405.2 of the Maryland Code and any successor provision, as amended from time to time, except to the extent (i) it is proved that the person actually received an improper benefit or profit in money, property or services, for the amount of the benefit or profit in money, property or services actually received, (ii) a judgment or other final adjudication adverse to the person is entered in a proceeding based on a finding in the proceeding that the person's action, or failure to act, was the result of active and deliberate dishonesty and was material to the cause of action adjudicated in the proceeding; or (iii) otherwise provided by the Maryland Code. Neither any amendment nor repeal of this Article IX, nor adoption of any provision of these Articles of Incorporation, the bylaws of the Corporation or any statute that is inconsistent with this Article IX, shall eliminate or reduce the effect of this Article IX in respect of any acts or omissions occurring prior to such amendment, repeal or adoption. If the Maryland Code is hereafter amended or supplemented to authorize corporate action further eliminating or limiting the personal liability of directors and officers, then the liability of directors and officers of the Corporation shall be eliminated or limited to the fullest extent permitted by such amended or supplemented Maryland Code. In the event that any of the provisions of this Article IX (including any provision within a single sentence) is held by a court of competent jurisdiction to be invalid, void or otherwise unenforceable, the remaining provisions are severable and shall remain enforceable to the fullest extent permitted by law.

## ARTICLE X
## INTERESTED PARTY TRANSACTIONS

The following provisions are inserted for the management of the business and for the conduct of the affairs of the Corporation, and the same are in furtherance of and not in limitation of, the powers conferred by law:

No contract or other transaction of the Corporation with any other persons, firm or corporation in which this Corporation is interested, shall be affected or invalidated by the fact that any one or more of the directors or officers of this Corporation, individually or jointly with others, may be a party to or may be interested in any such contract or transaction so long as the contract or other transaction is approved by the Board of Directors in accordance with the Maryland Code. Each person who may become a director or officer of the Corporation is hereby relieved from any liability that might otherwise arise by reason of his or her contracting with the Corporation for the benefit of himself or herself or any firm or corporation in which he or she may be in any way interested.

## ARTICLE XI
## INDEMNIFICATION

The Corporation shall indemnify and advance expenses to any and all directors, officers, employees and agents of the Corporation to the fullest extent permitted by Section 2−418 of the Maryland Code, as the same may be amended and supplemented, unless it is established that (i) the act or omission was material to the matter giving rise to the liability and was omitted in bad faith or was the result of active and deliberate dishonesty, (ii) the person actually received an improper personal benefit in money, property or services, or (ii) in the case of a criminal proceeding, the person had reasonable cause to believe the act or omission was unlawful. The rights to indemnification and advancement of expenses provided for herein shall not be deemed exclusive of any other rights to which those indemnified may be entitled under these Articles of Incorporation, any bylaw, agreement, vote of stockholders or disinterested directors or otherwise, both as to action in such persons' official capacity and as to action in another capacity while holding such directorship, office, employment or agency, and shall continue as to a person who has ceased to be a director, officer, employee or agent and shall inure to the benefit of the heirs, executors and administrators of such a person. Neither the repeal nor modification of this Article XI, or the adoption of any provision to these Articles of Incorporation that is inconsistent with this Article XI, shall eliminate, restrict or otherwise adversely affect any right or protection of any such person existing hereunder with respect to any act or omission occurring prior to such repeal, modification or adoption of an inconsistent provision.

## ARTICLE XII
## AMENDMENTS

The Corporation reserves the right to amend or repeal any provision contained in these Articles of Incorporation in the manner prescribed by the laws of the State of Maryland, including to change the name of the corporation or to change the name or other designation or the par value of any class or series of stock and the aggregate par value of that stock, and all rights conferred upon stockholders are granted subject to this reservation; provided, however, that, notwithstanding any other provision of these Articles of Incorporation or any provision of law which might otherwise permit a lesser vote or no vote, but in addition to any vote of the holders of any class or series of the stock of this Corporation required by law or by these Articles of Incorporation, the affirmative vote of the holders of at least 66 2/3% of the voting power of all of the then outstanding shares of the capital stock of the Corporation entitled to vote generally in the election of directors, voting together as a single class, shall be required to amend or repeal this Article XII, Article VII or Article VIII.

IN WITNESS WHEREOF, I have signed these Articles of Incorporation and acknowledge the same to be my act on this 19th day of May, 2004.

/s/ JOELLEN L. LEGG

JoEllen L. Legg, Incorporator

STATE OF COLORADO )
) ss.
CITY AND COUNTY OF DENVER )

BEFORE ME the undersigned authority, personally appeared JoEllen L. Legg, known to me to be the individual described in and who executed the foregoing Articles of Incorporation, and she acknowledged that she subscribed the said instrument for the uses and purposes set forth therein. The subscriber is personally known to me.

WITNESS my hand and official seal in the County and State last aforesaid this 19th day of May, 2004.

[Seal]

/s/ DORIS M. HAYUTIN

Notary Public
My Commission Expires: Dec. 1, 2005

**Exhibit 4.1**

WARREN RESOURCES, INC.

W __________
COMMON STOCK

CUSIP 93564A 10 0

TOTAL AUTHORIZED ISSUE
100,000,000 SHARES PAR VALUE $.0001 EACH

SEE REVERSE FORCERTAIN DEFINITIONS

INCORPORATED UNDER THE LAWS OF THE STATE OF MARYLAND

_______________IS THE OWNER OF______________________________________________________________
fully paid and non−assessable shares of the above Corporation transferable only on the books of the Corporation by the holder hereof in person or by duly authorized Attorney upon surrender of this Certificate properly endorsed.

This Certificate is not valid unless countersigned and registered by the Transfer Agent and Registrar.

Witness, the facsimile seal of the Corporation and the facsimile signatures of its duly authorized officers.

Dated _________________________

WARREN RESOURCES, INC.

SECRETARY
/s/ DAVID E. FLEMING

CHIEF EXECUTIVE OFFICER
/S/ NORMAN F. SWANTON

THIS IS TO CERTIFY THAT COMMON STOCK COUNTERSIGNED AND REGISTERED: AMERICAN STOCK TRANSFER & TRUST COMPANY (NEW YORK, N.Y.)

TRANSFER AGENT AND REGISTRAR

BY: ______________________________
AUTHORIZED SIGNATURE

---

[BACK]

The Corporation shall furnish without charge to each stockholder who so requests a statement of the powers, designations, preferences and relative, participating, optional or other special rights of each class of stock of the Corporation or series thereof and the qualifications, limitations or restrictions of such preferences and/or rights. Such requests shall be made to the Corporation’s Secretary at the principal office of the Corporation. The following abbreviations, when used in the inscription on the face of this certificate, shall be construed as though they were written out in full according to applicable laws or regulations:

TEN COM− as tenants in common
TEN ENT − as tenants by the entireties
JT TEN − as joint tenants with right of survivorship and not as tenants in common
UNIF GIFT MIN ACT– __________ Custodian __________ (Cust) (Minor) under Uniform Gifts to Minors Act
____________________ (State)
UNIF TRF MIN ACT– .__________ Custodian (until age........) (Cust) ____________________ under Uniform Transfers (Minor) to Minors Act ____________________ (State)

Additional abbreviations may also be used though not in the above list.

PLEASE INSERT SOCIAL SECURITY OR OTHER
IDENTIFYING NUMBER OF ASSIGNEE

FOR VALUE RECEIVED, ____________________ hereby sell, assign and transfer unto ____________________ (PLEASE PRINT OR TYPEWRITE NAME AND ADDRESS, INCLUDING ZIP CODE, OF ASSIGNEE) shares of the common stock represented by the within Certificate, and do hereby irrevocably constitute and appoint __________ attorney to transfer the said stock on the books of the within named Corporation with full power of substitution in the premises.

Dated ____________________

______________________________
Signature

**NOTICE:** THE SIGNATURE(S) TO THIS ASSIGNMENT MUST CORRESPOND WITH THE NAME(S) AS WRITTEN UPON THE FACE OF THE CERTIFICATE IN EVERY PARTICULAR, WITHOUT ALTERATION OR ENLARGEMENT OR ANY CHANGE WHATEVER.

Signature(s) Guaranteed:
By: ________________________________________

THE SIGNATURE(S) MUST BE GUARANTEED BY AN ELIGIBLE GUARANTOR INSTITUTION (BANKS, STOCKBROKERS, SAVINGS AND LOAN ASSOCIATIONS AND CREDIT UNIONS) WITH MEMBERSHIP IN AN APPROVED SIGNATURE GUARANTEE MEDALLION PROGRAM, PURSUANT TO S.E.C. RULE 17Ad−15.

**Exhibit 23.1**

**CONSENT OF WILLIAMSON PETROLEUM CONSULTANTS, INC.**

As independent oil & gas consultants, Williamson Petroleum Consultants, Inc. hereby consents to the use of the name Williamson Petroleum Consultants, Inc. and references to Williamson Petroleum Consultants, Inc. and to the inclusion of and references to our report, or information contained therein, entitled "Evaluation of Oil and Gas Reserves to the Combined Interests of Warren Resources, Inc. including 1) the Direct Interests in Certain Properties, 2) the Interests as the General Partner in Certain Partnerships, and 3) the Total Controlled Interests in 13 LLC's Effective December 31, 2004 for Disclosure to the Securities and Exchange Commission Williamson Project 4.9026," prepared for Warren Resources, Inc., in the annual report on Form 10−K of Warren Resources, Inc. for the filing dated on or about March 10, 2005. .

/s/ Williamson Petroleum Consultants, Inc.

WILLIAMSON PETROLEUM CONSULTANTS, INC.

Midland, Texas
March 10, 2005

**Exhibit 23.2**

**CONSENT OF CBIZ VALUATION GROUP, LLC**

As independent valuation consultants, CBIZ Valuation Group, LLC hereby consents to the use of the name CBIZ Valuation Group, LLC and references to CBIZ Valuation Group, LLC and to references to our report entitled “Statement of Financial Accounting Standards 142 Analysis” prepared for Warren Resources, Inc., or information contained therein, for disclosure to the Securities and Exchange Commission in the annual report on Form 10−K of Warren Resources, Inc. for the filing dated on or about March 10, 2005.

/s/ CBIZ Valuation Group, LLC

CBIZ VALUATION GROUP, LLC

March 10, 2005
Dallas, Texas

**Exhibit 31.1**

**CERTIFICATION PURSUANT TO**
**SECTION 302 OF THE SARBANES−OXLEY ACT OF 2002**

I, Norman F. Swanton, certify that:

1) I have reviewed this annual report on Form 10−K of Warren Resources, Inc.;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5) The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over the financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Norman F. Swanton

Norman F. Swanton,
Chairman and Chief Executive Officer

Date: March 15, 2005

**Exhibit 31.2**

**CERTIFICATION PURSUANT TO**
**SECTION 302 OF THE SARBANES−OXLEY ACT OF 2002**

I, Timothy A. Larkin, certify that:

1) I have reviewed this annual report on Form 10−K of Warren Resources, Inc.;

2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4) The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting;

5) The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over the financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors:

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Timothy A. Larkin

Timothy A. Larkin,
Executive Vice President and Chief Financial Officer

Date: March 15, 2005

**Exhibit 32**

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES−OXLEY ACT OF 2002**

In connection with the Annual Report of Warren Resources, Inc. (the "Company") on Form 10−K for the year ending December 31, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "report"), we, Norman F. Swanton and Timothy A. Larkin, Chairman and Chief Executive Officer and Executive Vice President and Chief Financial Officer, respectively, of the registrant, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes−Oxley Act of 2002, that to our knowledge:

(1) The report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Norman F. Swanton

Norman F. Swanton
Chairman and Chief Executive Officer

/s/ Timothy A. Larkin

Timothy A. Larkin
Executive Vice President and Chief Financial Officer

March 15, 2005