FORM 10−K

WARREN RESOURCES INC − WRES

Filed: March 06, 2007 (period: December 31, 2006)

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, 2006

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	**11−3024080**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
489 Fifth Avenue, New York, NY	**10017**
(Address of principal executive offices)	(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 if the registrant is a well−known seasoned issuer, as defined in Rule 405 of the Securities Act. ☒ Yes ☐ No

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

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 a large accelerated filer, an accelerated filer, or a non−accelerated filer (as defined in Rule 12b−2 of the Act).

Large accelerated filer ☐ Accelerated filer ☒ Non−accelerated filer ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b−2 of the Act). ☐ Yes ☒ No

The aggregate market value of the registrant's common stock held by non−affiliates of the registrant on June 30, 2006 was $ 550,013,905.

The number of shares of registrant's common stock outstanding as of March 2, 2007 was 54,143,054 shares.

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 30, 2007, in connection with the registrant's 2007 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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As used in this document, "Warren", "the Company", "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.

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".

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 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), that involve a number of risks and uncertainties.

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

- our business and growth strategies;
- our oil and natural gas reserve estimates;
- our ability to successfully and economically explore for and develop oil and gas resources;
- our exploration and development drilling prospects, inventories, projects and programs;
- availability and costs of drilling rigs and field services;
- 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;
- 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, including delays in obtaining permits;
- hazardous and risky drilling operations; and
- an inability to meet growth projections.

You should also consider carefully the statements under “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 coalbed methane, or CBM, natural gas properties located in the Rocky Mountain region and on our waterflood oil recovery programs in the Wilmington field within the Los Angeles Basin of California.

As of December 31, 2006, we owned natural gas and oil leasehold interests in approximately 272,241 gross (152,596 net) acres, 92% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains. We have identified approximately 1,900 drilling locations on our acreage in the Rocky Mountains, primarily on 80−acre well spacing. Additionally, we have identified approximately 450 drilling locations in the Wilmington field.

As of December 31, 2006, we had estimated net proved reserves of 349.3 Bcfe, with a PV−10 value of $608.9 million, based on a reserve report prepared by Williamson Petroleum Consultants, Inc. These estimated net proved reserves are located on less than 10% of our total net acreage. Based on our preliminary results to date, we believe that a substantial amount of our remaining undeveloped CBM acreage in the Rocky Mountain Region has commercial potential.

As of December 31, 2006, we had interests in 297 gross (180 net) producing wells and are the operator of record or co−operator for 89% 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. For the month of December 2006, our average daily production was 25.5 million cubic feet per day (“MMcfe/d”) gross (11.8 MMcfe/d net). For 2007, we have a total capital expenditure budget of approximately $121 million.

Business Strategy

The principal elements of our business strategy are designed to grow our 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 have identified a total of approximately 2,350 drilling locations, of which 1,900 are in our Rocky Mountain CBM properties, 400 are in our Wilmington Townlot Unit and 50 are in the North Wilmington Unit. We plan to participate in the drilling of 142 gross wells (including injector wells) during 2007, of which 82 are in our Rocky Mountain properties and 60 are in our Wilmington field.

- *Increase proved reserves*. We intend to increase our proved reserves and production by drilling an increased number of wells on our undeveloped, unproved acreage, which represents 92% of our acreage position at December 31, 2006.
- *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. For example, the acquisitions of the Wilmington Townlot Unit and the North Wilmington Unit. We are also joint venture partners in the Atlantic Rim project in Wyoming with Anadarko Petroleum Corporation, one of the largest independent oil and gas exploration and production companies in the world. We expect to pursue further acquisitions of natural gas and oil properties in areas where we have specific technical knowledge and experience.
- *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. As of December 31, 2006, we have assembled a substantial undeveloped acreage position in the Rocky Mountains of 237,997 gross (136,480 net) acres containing approximately 1,900 identified drilling locations. In the Rocky Mountains, our estimated total net proved reserves of 21.6 Bcf are located on approximately 7% of our total net acreage.
- *Significant Development Opportunity in the Los Angeles Basin of California*. We believe that our Wilmington Townlot Unit, together with the North Wilmington Unit, provide us a significant development opportunity of long−lived oil reserves in a historically prolific basin. The Wilmington Townlot Unit and North Wilmington Unit combined comprise approximately 2,476 gross (2,406 net) acres within the Los Angeles basin and contains approximately 450 identified drilling locations for producing wells. As of December 31, 2006, 82% of our proved reserves in the Wilmington field were undeveloped.
- *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 Townlot Unit.
- *Experienced Management Team*. Our management team has 29 years of experience on average in the oil and gas industry, and our technical professionals have 26 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 2, 2007, our 13 directors and executive officers

beneficially owned 4,401,181 shares of common stock, which includes exercisable options to purchase 2,125,583 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 projects in the Wilmington field in California. The table below highlights our main areas of activity:

Area	Gross Acres	Net Acres	Planned Gross Wells in 2007
Atlantic Rim Project	209,248	110,930	80
Pacific Rim Project	35,846	28,190	2
South Seminoe Prospect	14,187	7,094	—
Powder River Basin	3,110	1,332	—
Wilmington Field	2,476	2,406	60
Other(1)	7,374	2,644	—
Total	272,241	152,596	142

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

Rocky Mountain Projects in the Washakie Basin

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, 2006, we had assembled 245,094 gross (139,120 net) acres prospective for CBM development in this area, of which 129,305 net acres are undeveloped. This area contains approximately 1,900 identified drilling locations primarily on 80−acre well spacing. The report prepared by Williamson Petroleum Consultants as of December 31, 2006 estimates that the gross recoverable proved reserves for the 62 CBM wells drilled and their 43 well offsets in our first three CBM pilot programs in this basin were 75.2 Bcf gross (21.6 Bcf net) on 80−acre well spacing. We own a 57% average working interest to the base of the Mesa Verde formation in this acreage.

In addition to this acreage, we have the rights to drill and develop the deeper, conventional formations (“deep rights”) in some, but not all, of the acreage in the Atlantic Rim Area. We own approximately 89,930 gross (74,015) net) undeveloped acres of deep rights inside the AMI with Anadarko, and approximately 29,438 gross (26,910 net) undeveloped acres of deep rights outside the AMI, for a total of 119,368 gross (100,925 net) undeveloped acres in the entire Atlantic Rim Area. These deep rights are also subject to the pending EIS covering the shallow rights in the Atlantic Rim Area. The EIS contemplates that approximately 200 conventional wells will be drilled to the deep rights owned by Warren and the other operators within the EIS boundary covering the Atlantic Rim Area. We anticipate receiving a Record of Decision approving the EIS in the first quarter of 2007.

Commercial CBM production in the Washakie Basin was initially established in 2002 on the eastern rim of the Washakie Basin by Warren and Double Eagle Petroleum Co., an independent energy company. Current development in the Washakie Basin is targeting 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 209,248 gross (110,930 net) acres on the eastern rim of the Washakie Basin. We drilled a total of 24 CBM wells in the Atlantic Rim project in 2006, for a total of 152 wells. Additionally, upon completion of an ongoing environmental impact study (“EIS”) being conducted on the Atlantic Rim area by the Rawlins Office of the Bureau of Land Management (“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 the first quarter of 2007. Currently, 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 in 2001 on 80−acre spacing. In 2004 we drilled an additional 2 CBM gross (0.3 net) wells and a second water injection well. Production commenced 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. As of December 31, 2006, these wells were producing 4,212 Mcf per day of gas and 11,500 Bbls/d of water. Based on a report from Williamson Petroleum Consultants, as of December 31, 2006, estimated gross ultimate recoverable proved reserves for the 12 producing wells and 14 undrilled offset locations in the Sun Dog unit average 0.9 Bcfe per well. We currently own a working interest of approximately 27% in the wells drilled in the initial pod of the Sun Dog unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

Blue Sky Unit

The Blue Sky unit is a 23−well pilot program originally drilled on 160−acre spacing. This program commenced production in August 2003 and as of December 31, 2006, was producing 402 Mcf/d of natural gas and approximately 25,000 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. During 2005, we drilled an additional 11 CBM wells in this unit to reduce the well spacing to 80−acres. Based on a report from Williamson Petroleum as of December 31, 2006, estimated gross ultimate recoverable proved reserves for the 22 producing wells in the Blue Sky unit average 0.5 Bcfe per well. We currently own an approximate 13% working interest in the wells drilled in the initial pod of the Blue Sky unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

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, another eight wells during 2004 and an injector well in 2005. The installation of a gathering system was completed in 2005. These 16 wells are currently in the dewatering stage. We own a working interest of approximately 13% in the wells drilled in the initial pod of the Red Rim unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 46% if the existing unit is fully drilled and developed.

Doty Mountain Unit

The Doty Mountain unit consists of 46 wells on 80−acre spacing. In 2004, we drilled 24 wells and one water injection well. In 2006, we drilled and completed an additional 22 wells. The first 24 wells in this program commenced production in February 2005 and as of December 31, 2006, was producing 1,335 Mcf/d of natural gas and approximately 7,800 Bbls/d of water. We anticipate that the 22 recently drilled wells will be producing by March 2007. We currently own an approximate 9% working interest in the wells drilled in the initial pod of the Doty Mountain unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

Jolly Roger Unit

The Jolly Roger unit consists of 24 wells on 160−acre spacing. We drilled eight wells and one water injection well in 2002 and drilled 16 wells, one water injection well and one monitor well in this unit in 2005. These wells are currently in the dewatering stage. We currently own a working interest of approximately 11% in the wells drilled in the initial pod of the Jolly Roger unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 43% if the existing unit is fully drilled and developed.

Pacific Rim Project

Our Pacific Rim acreage is located on the western rim of the Washakie Basin, approximately 60 miles west of our Atlantic Rim project. At December 31, 2006, this project comprised approximately 35,846 gross (28,190 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.

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

During 2003 and 2004 Warren drilled the first CBM pilot in the Pacific Isle Unit consisting of 15 producers and 1 injection well. After extensive production testing Warren has determined that the combination of low permeability in the coal and communication with the adjacent water sands resulted in a non−effective dewatering profile for commercial CBM production in the unit. Warren discontinued its CBM effort in the Pacific Isle Unit. At December 31, 2006, Warren wrote off all non−salvageable costs relating to the Pacific Isle unit.

Chicken Springs Unit

We are currently developing our first pod in the Chicken Springs unit. This pod consists of seven wells, one of which we drilled in the second quarter of 2004, three of which we drilled in 2005 and three which were drilled in 2006. As of December 31, 2006, the Chicken Springs wells were producing 356 Mcf/d of natural gas. We currently own an approximate 13% working interest in the wells drilled in the initial pod of the Chicken Springs unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 50% 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 ten wells, one of which we acquired with the property, and four of which were drilled in the fourth quarter of 2004. We drilled an additional five CBM wells in the first quarter of 2006. Warren is currently production testing this ten well pilot to determine the commercial potential of CBM potential in the Rifes Rim Unit. We currently own a working interest of approximately 18% in the wells drilled in the initial pod of the Rifes Rim unit. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 72% if the existing unit is fully drilled and developed.

South Seminoe Prospect in the Hanna Basin

During 2005, we acquired a 50% working interest in 14,187 gross (7,094 net) acres located in the Hanna Basin of south central Wyoming. Warren also secured 50% interest in a farm−in on 5,600 gross acres adjacent to these leases. Seismic data from this prospect indicates the potential presence of a structure that may contain pay zones from the shallower Shannon zone to the deeper Ten Sleep formation.

Warren, along with its 50% working interest partner Stone Energy, began drilling the first exploratory well on this prospect during 2006. Warren has set 7 inch liner to a depth of 15,074 feet and is currently drilling ahead to evaluate the Ten Sleep. Currently the Company is drilling the top of the Ten Sleep formation at approximately 16,200 feet.

Powder River Basin

At December 31, 2006, we owned and operated interests in 70 gross (39 net) producing CBM wells in 3,110 gross (1,332 net) acres in the Powder River Basin near Gillette, Wyoming. At December 31, 2006, these wells were producing approximately 2,416 Mcf/d gross (843 Mcf/d net). At December 31, 2006, our total estimated net proved reserves in this portion of the Powder River Basin were 4.2 Bcf gross (1.8 Bcf net).

Southern California Projects

Wilmington Townlot Unit

Our Wilmington Townlot 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 1930s. Since that time, the Wilmington Townlot Unit, a unitized oil field consisting of 1,440 gross (1,370 net) acres, has produced more than 149 million barrels of oil from primary production. All the working interests in the Wilmington Townlot Unit are subject to the terms and provisions of a unit operating agreement. We hold an approximate 98.5% undivided working interest in the Wilmington Townlot Unit.

Our Wilmington Townlot 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, 2006, we had 1,613 barrels of oil per day (“Bbls/d”) gross, (1,287 Bbls/d net) production, compared to 760 Bbls/d gross (551 Bbls/d net) production as of December 31, 2005. In addition, estimated proved reserves as of December 31, 2006 were 43 MMbbls gross (34 MMbbls net), of which 76% are PUDs. Further, as of December 31, 2006, there were 73 gross (72 net) producing wells.

North Wilmington Unit

The North Wilmington Unit is located in the Wilmington oil field adjacent to our existing Wilmington Townlot Unit. Since its discovery in the 1930s, this unitized oil field consisting of approximately 1,036 gross and net acres has produced more than 37.6 million barrels of oil. All working interests in the North

Wilmington Unit are subject to the terms and provisions of a unit operating agreement. We own a 100% working interest and an approximate 84.5% net revenue interest in the North Wilmington Unit field, including existing wells, certain equipment and certain surface properties.

The North Wilmington Unit oil reserves are primarily PUDs. Based on a report of Williamson Petroleum Consultants as of December 31, 2006, the estimated net proved reserves attributable to the North Wilmington Unit are 117.9 Bcfe net. 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, 2006, production from the North Wilmington Unit was 381 Bbls gross (322 Bblsd net).

Drilling Programs

Since 1992, we have sponsored 31 drilling programs that have raised approximately $228 million. We have not sponsored drilling programs since 2003. At December 31, 2006, we served as managing general partner for seven remaining drilling programs. These partnerships were formed between 1999 and 2003, and will continue to operate until their partners vote otherwise.

We act as the sole managing general partner of each drilling program. 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, 2006, none of the active seven remaining drilling programs managed by us had achieved payout status. Because we serve as the managing general partner of these entities, under state partnership law we are contingently liable for the liabilities of these partnerships, which liabilities are not material for any of the periods presented in relation to the partnerships' respective assets.

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.

During the first quarter of 2006, the investor partners of the 1998 drilling partnerships voted to approve the sale of all of the oil and gas assets of the drilling partnerships to us. As a result, the Company issued 387,492 restricted shares of common stock under Regulation D (restricted for at least one year) in exchange for both producing and non−producing properties. The number of shares issued was determined based upon a 20% discount from the weighted average sales price for Warren's publicly traded common stock for the forty−five (45) calendar days ending March 31, 2006. The Company recorded the transaction based on the undiscounted weighted average price of its common stock for the forty−five (45) calendar days ending March 31, 2006. These shares were valued at approximately $5.5 million. The Company also issued a total of 54,225 shares to two individuals in exchange for their interests in three drilling partnerships. These shares were valued at $817,646 based on the price of our stock on the date of issuance.

Also, during the three months ended March 31, 2006, the Company acquired all minority interests in the 1994 thru 1997 drilling partnerships for approximately $1.4 million in cash. The minority interest relating to these partnerships was recorded as a reduction in the cost basis of the assets acquired.

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, 2006, 2005 and 2004 based on reserve reports prepared by Williamson Petroleum. 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 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, 2006, none of the active 7 drilling programs managed by us had achieved payout status.

	Years Ended December 31,		
	2006	2005	2004
Estimated Proved Natural Gas and Oil Reserves:			
Net natural gas reserves (MMcf):			
Proved developed	9,264	10,829	8,496
Proved undeveloped	15,561	13,524	10,046
Total(1)	24,825	24,353	18,542
Net oil reserves (MBbls):			
Proved developed	9,583	2,938	395
Proved undeveloped	44,494	47,477	13,781
Total(2)	54,077	50,415	14,176
Total Net Proved Natural Gas & Oil Reserves (MMcfe)	349,290	326,845	103,601
Estimated Present Value of Net Proved Reserves:			
PV−10 Value (in thousands)			
Proved developed	$ 205,683	$ 107,639	$ 26,901
Proved undeveloped	403,201	530,280	215,392
Total(3)	608,884	637,919	242,293
Less: future income taxes, discounted at 10%	196,308	175,139	49,648
Standardized measure of discounted future net cash flows (in thousands)(4)	$ 412,576	$ 462,780	$ 192,645
Prices Used in Calculating Reserves:			
Natural Gas (per Mcf)	$ 4.35	$ 9.92	$ 5.30
Oil (per Bbl)	$ 50.60	$ 49.05	$ 37.59
Proved Developed Reserves (MMcfe)	66,763	28,461	10,866

(1) Included in 2005 and 2004 reserves, 136 MMcf and 357 MMcf is attributable to consolidated subsidiaries in which there is an average minority interest of 9% and 23%, respectively.

(2) Included in 2005 and 2004 reserves, 922 MBbls and 2,142 MBbls is attributable to consolidated subsidiaries in which there is an average minority interest of 9% and 23%, respectively.

(3) The PV−10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10% per annum. Although it is a non−GAAP measure, we believe that the presentation of the PV−10 Value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and our current tax structure. We use this measure when assessing the potential return on investment related to our oil and gas properties. Our reconciliation of this non−GAAP financial measure is shown in the table as the PV−10, less future income taxes, discounted at 10% per annum, resulting in the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to our proved oil and natural gas reserves after income tax, discounted at 10%. In accordance with SEC requirements, our reserves and the future net revenues were

determined using realized prices for natural gas and oil at each of December 31, 2006, 2005, and 2004, which were, $ 4.35 per Mcf of natural gas and $ 50.60 per barrel of oil at December 31, 2006, $9.92 per Mcf of natural gas and $49.05 per barrel of oil at December 31, 2005 and $5.30 per Mcf of natural gas and $37.59 per barrel of oil at December 31, 2004. These prices reflect adjustment by lease for quality, transportation fees and regional price differences.

(4) Standardized measure of discounted future net cash flows differs from PV−10 value because it includes the effect of future income taxes. Included in 2005 and 2004 standardized measure of discounted future net cash flows $9,673 and $23,017 is attributable to consolidated subsidiaries in which there is an average minority interest of 9% and 23%, respectively.

The data in the above natural gas and oil reserves table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. See “Risk Factors”.

PV−10 is equal to the future net cash flows from our proved reserves at December 31, 2006, excluding any future income taxes, discounted at 10% per annum (“PV−10”). Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on undrilled acreage for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells on which a relatively major expenditure is required to establish production. PV−10 may be considered a non−GAAP financial measure as defined by Item 10(e) of Regulation S−K and is derived from the standardized measure of discounted future net cash flows which is the most directly comparable GAAP financial measure. PV−10 is a computation of the standardized measure of discounted future net cash flows on a pre−tax basis. We believe that the presentation of the PV−10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account corporate future income taxes and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. However, PV−10 is not a substitute for the standardized measure of discounted future net cash flows.

Due to the volatility of commodity prices, the oil and gas prices on the last day of the period significantly impact the calculation of the PV−10 and the standardized measure of discounted future net cash flows. The present value of future net cash flows does not purport to be an estimate of the fair market value of the Company’s proved reserves. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil and gas. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The 10% discount factor used to calculate present value, which is required by Financial Accounting Standard Board pronouncements, may not necessarily be the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate.

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 there from, 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, 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, 2006:

	Natural Gas Wells		Oil Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
California	—	—	125.0	124.0	125.0	124.0
New Mexico	20.0	0.7	3.0	0.1	23.0	0.8
Texas.	9.0	1.7	—	—	9.0	1.7
Wyoming	138.0	53.0	—	—	138.0	53.0
Other	—	—	2.0	0.1	2.0	0.1
Total	167.0	55.4	130.0	124.2	297.0	179.6

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:

	Years Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells(1)						
Productive(2)	37.0	20.0	21.0	2.4	52.0	5.1
Nonproductive(3)	2.0	0.7	—	—	1.0	0.1
Development Wells(1)						
Productive(2)	28.0	27.9	27.0	13.3	14.0	2.1
Nonproductive(3)	—	—	—	—	1.0	0.3
Total	67.0	48.6	48.0	15.7	68.0	7.6

(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, 2006:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	878	852	1,598	1,554	2,476	2,406
New Mexico	1,066	98	2,924	351	3,990	449
Texas	704	176	—	—	704	176
Wyoming	24,397	11,066	237,997	136,480	262,394	147,546
Other	945	419	1,732	1,600	2,677	2,019
Total	27,990	12,611	244,251	139,985	272,241	152,596

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 production is attributable to our direct interests in producing properties and the production we are allocated from our interest in our drilling 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 relates to our net production.

	Years Ended December 31,		
	2006	2005	2004
Production:			
Natural gas (MMcf)	1,052.1	1,073.5	817.2
Oil (MBbls)	455.8	147.6	68.2
Total equivalents (MMcfe)	3,787.2	1,958.9	1,226.3
Average Sales Price Per Unit:			
Natural gas (per Mcf)	$ 5.73	$ 6.71	$ 5.03
Oil (per Bbl)	55.36	45.75	34.38
Weighted average (per Mcfe)	8.25	7.13	5.26
Expenses (per Mcfe):			
Lease operating expense(1)	$ 3.69	$ 3.64	$ 3.12

(1) 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 47% of our natural gas production was subject to a firm commitment contract for transportation space, but not sales, with Williston Basin Interstate relating to our LX−Bar lease for 2,000 Mcf/d, which will expire on March 31, 2007. We sell our natural gas at market price. 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 “Risk Factors”.

For 2006, the largest purchasers and marketers for our production and that of our drilling programs primarily included ABQ Energy Group, LTD, Anadarko Energy Services, Conoco Phillips, Inc. and Lunday−Thagard Company, which accounted for 12%, 14%, 54% and 18%, 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.

Through Warren E&P, we employ petroleum engineers, drilling supervisors, landmen and field supervisors. Warren E&P also employs geologists and other personnel on a contract basis. As of December 31, 2006, Warren E&P was the operator or co−operator of approximately 89% 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; that we can sell interests in natural gas and oil leases; or that we can obtain financing for, or locate participants to join in the development of prospects.

Regulations and Environmental Matters

General. Our operations are subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Our operations are subject to the same environmental laws and regulations as other companies in the oil and gas exploration and production industry. These laws and regulations may:

- require the acquisition of various permits before drilling commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;
- Limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closure and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations;
- with respect to operations affecting federal lands or leases, require time consuming environmental analysis; and
- expose the Company to litigation by environmental and other special interest groups.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and the federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly waste handling, disposal and clean−up requirements for the oil and gas industry could have a significant impact on our operating costs. We believe that we substantially comply with all current applicable environmental laws and regulations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. However, we cannot predict the passage of or quantify the potential impact of more stringent future laws and regulations at this time. For the year ended December 31, 2006, we did not incur any material capital expenditures for remediation or retrofit of pollution control equipment at any of our facilities.

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

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will have an environmental assessment, or EA, prepared that assesses the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study, or EIS, that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

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.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, affect oil and gas exploration and production activities by imposing regulations on the generation, transportation, treatment, storage, disposal and cleanup of “hazardous wastes” and on the disposal of non−hazardous wastes. Under the auspices of the Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of crude oil, natural gas, or geothermal energy constitute “solid wastes”, which are regulated under the less stringent non−hazardous waste provisions, but there is no guarantee that the EPA or the individual states will not adopt more stringent requirements for the handling of non−hazardous wastes or categorize some non−hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re−categorize certain oil and gas exploration and production wastes as “hazardous wastes”.

We believe that we are in substantial compliance with the requirements of RCRA and related state and local laws and regulations, and that we held all necessary and up−to−date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), also known as the “superfund” law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site, or site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substance. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA for all or part of the costs to clean up sites at which such “hazardous substances” have been deposited.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the state. These prescriptions also prohibit the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non−compliance with discharge permits or other requirements of the federal Clean Water Act and analogous state laws and regulations. Response costs could be high and may have a material adverse effect on our operations. We may not be fully insured for these costs. We maintain all required discharge permits necessary to conduct our operations, and we believe we are substantially compliant with the terms thereof. Obtaining permits has the potential to delay the development of oil and natural gas projects. 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.

Air Emissions. The Federal Clean Air Act, and associated state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Some of our new facilities will be required to obtain permits before work can begin, and existing facilities may be required to incur capital costs in order to remain in compliance. These regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non−compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. We believe that we are in substantial compliance with all air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining permits has the potential to delay the development of oil and natural gas projects.

Other Environmental Laws and Regulation. The Kyoto Protocol to the United Nations Framework Convention on Climate Change went into effect in February 2005 and requires all industrialized nations that ratified the Protocol to reduce or limit greenhouse gas emissions to a specified level by 2012. The United States has not ratified the Protocol, and the U.S. Congress has resisted recent proposed legislation directed at reducing greenhouse gas emissions. However, there is increasing public pressure from environmental groups and some Northeastern and West Coast states for the United States to develop a national program for regulating greenhouse gas emissions, and several states have already adopted regulations or announced initiatives focused on decreasing or stabilizing greenhouse gas emissions associated with industrial activity, primarily carbon dioxide emissions from power plants. The oil and natural gas exploration and production industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting of natural gas could impact our future operations. Our operations are not adversely impacted by current state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

Operating Regulation of the Oil and Gas Industry

In addition to environmental laws and regulations, exploration, production and operations in the oil and gas industry are extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production. Our operations are subject to various types of regulation at federal, state, and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled and other third parties;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of natural gas and oil we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Natural Gas Sales Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The Federal Energy Regulatory Commission, or FERC, has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non−price controls for sales of domestic natural gas sold in “first sales”, which include all of our sales of our own production.

FERC also regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, unregulated, open access market for gas purchases and sales that permits all purchasers of gas to buy gas directly from third−party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open−access, non−discriminatory basis at cost−based rates or at market−based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by state agencies. Although its policy is still in flux, FERC recently has reclassified certain jurisdictional transmission facilities as non−jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point−of−sale locations.

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 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.

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, spacing and 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.

Future Regulations

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.

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. 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. 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 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 policy have been adequate to meet the applicable bonding and insurance requirements to date. Finally, we have posted a $3.0 million U.S. treasury bond, with a fair value of $2,902,000 as of December 31, 2006, as collateral for a $3.4 million reclamation bond for the Wilmington Townlot 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 operations. This produced water is disposed of by re−injection into the subsurface through disposal wells, and, in some cases, 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 final Atlantic Rim EIS was completed in December 2006 and record of decision is expected during the first quarter of 2007.

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.

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 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 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 currently existing 20,885 gross (17,207 net) acres comprising our Pacific Rim project area. The Pacific Rim EA contemplates the drilling of 120 CBM wells in the study area. A record of decision on this EA was issued by the BLM in the third quarter of 2004. As is now common practice after each EA is granted, several environmental organizations objected to the approval of the EA. After an appeal by the environmental groups for a State Director Review, the Wyoming State Office affirmed the decision record for the EA and denied their request for stay. Thereafter, the environmental organizations filed an appeal and requested a stay from the IBLA. In February 2005, the IBLA issued an order denying their petition for a stay. The environmental organizations continue to appeal to the IBLA by attacking the approval of the EA by the BLM, but no further decision has been made by the IBLA. However, by issuing its order refusing to grant a stay, the IBLA has allowed our drilling to proceed. We were allocated approximately 80 of the 120 wells in the EA study area. We have drilled approximately 24 wells in the Pacific Rim. 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 late 2007.

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 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 Field

The Wilmington Townlot Unit and the North Wilmington Unit are located in a mixed 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 field 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 Townlot Unit and North 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 either the Wilmington Townlot Unit or North Wilmington Unit.

Operating Hazards And Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, 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 or landmen. 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, 2006, we had 57 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 activities. 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 March 2008. Our oil and gas operations office in Casper, Wyoming occupies 3,750 square feet under a lease currently being negotiated. Our oil and gas operations office in Long Beach, California occupies 2,206 square feet of space under a lease that was entered into in February 2005, which expires in June 2010. In June 2005, we entered into an office lease in Roswell, New Mexico, which expires in May 2007. We believe that suitable additional space to accommodate our anticipated growth will be available in the future on commercially reasonable terms.

Website and Code of Business Conduct and Ethics

Our website address is http://www.warrenresources.com. 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 all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC at http://www.sec.gov. Additionally, our Code of Business Conduct and Ethics, which includes our code of ethics for senior financial management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are posted on our website and are available in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our principal office at 489 Fifth Avenue, 32nd Floor, New York, NY 10017.

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 are 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.

Down−dip. The occurrence of a formation at a lower elevation than a nearby area.

Drill−to−earn. The process of earning an interest in leasehold acreage by drilling a well pursuant to a farm−in or exploration agreement.

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 Farm−in. 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.

Finding and Development Costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

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 or laterally within a productive or potentially productive 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.

Infill Drilling. The drilling of wells between established producing wells on a lease to increase reserves or productive capacity from the reservoir.

Injection Well or Injector. A well which is used to place water, liquids or gases into an underground zone to assist in maintaining reservoir pressure, enhancing recoveries from the field, or disposal of produced water.

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 work;
- 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 and explore for, drill for, produce, store and remove oil and natural gas from 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. One 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 Revenue Interest. An owner’s interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Net wells. The sum of all of Warren’s full and partial well ownership interests (i.e., if we own 25% percent of 100% working interest in eight producing wells, 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 well before it is drilled into.

PDNP. Proved developed nonproducing.

PDP. Proved developed producing.

Permeability. A measure of the resistance or capacity of a geologic formation to allow water, natural gas or oil to pass through it.

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.

Pod. A grouping of 5 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.

PUD. Proved undeveloped.

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 operating and 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 (PDP). 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.

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%.

Recompletion. The process of re−entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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.

Stratigraphic Play. An oil or natural gas formation contained within an area created by permeability and porosity changes characteristic of the alternating rock layer that result from the sedimentation process.

Structural Play. An oil or natural gas formation contained within an area created by earth movements that deform or rupture (such as folding or faulting) rock strata.

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; and
- 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.

Tight gas sands. A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

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.

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

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.

Item 1A: 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 annual report. 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 and oil prices and other factors, many of which are beyond our control.

As of December 31, 2006, approximately 82% 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 for 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.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Under these laws and regulations, we could be held liable for personal injuries, property damage (including site clean−up and restoration costs), and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resources damages. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact statements, studies, reports and/or plans of development before commencing exploration and production activities. These regulations affect our operations and limit the quantity of oil and natural gas we may be able to produce and sell.

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. On December 1, 2006, the U.S. Bureau of Land Management, or BLM, released a final environmental impact statement, or EIS, which includes and 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 timing and location of wells that may be drilled in the Atlantic Rim. The record of decision for the final EIS is currently expected to be made by the

BLM during the first quarter of 2007, although this projected completion date may be extended. Our prior drilling in this basin, along with our projected drilling through 2007, has been and 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 record of decision may not be completed during the first quarter of 2007, 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. Additionally, in the Pacific Rim a record of decision on an EA was granted in the third−quarter of 2004 by the BLM allowing the drilling of up to 120 wells. After the EA was approved, several environmental, anti−development organizations objected to the granting of the EA and sought to stay our, and other oil and gas owners, ability to proceed with drilling. The environmental organizations first appealed for a State Director Review, and the Wyoming State Office affirmed the decision record for the EA and denied their request for stay. Thereafter, the environmental organizations appealed the EA and sought a stay from the IBLA. In February 2005, the IBLA issued an order denying the petition for a stay filed by environmental organizations. The environmental organizations are continuing the IBLA appeal by attacking the granting of the EA by the BLM. As of this date, their appeal is currently pending and awaiting action by the IBLA. However, by not allowing a stay, the IBLA has ordered that our drilling under the EA can proceed. We were allocated approximately 80 of the 120 wells in the EA study area. We have drilled approximately 24 wells in the Pacific Rim. 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 a full EIS for the Pacific Rim project will be necessary before late 2007.

A major risk inherent in our drilling plans is the need to obtain drilling permits from applicable federal, state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating area. 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 as planned. We cannot predict the timing or outcome of the record of decision for the final Atlantic Rim 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. See “Items 1 and 2. Business and Properties—Business—Operations—Environmental Matters and Regulation”.

Our substantial contingent obligations to repurchase drilling program interests could strain our financial resources.

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.

Under the terms of our five drilling programs formed between 1999 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, 2006 based on the December 31, 2006 reserve reports of the respective drilling programs, the aggregate PV−10 value of the assets in these programs was $13.0 million. Because this amount is less than the formula price of $73.9 million as of December 31, 2006, the PV−10 of $13.0 million is our maximum repurchase obligation as of December 31, 2006. This PV−10 amount may increase when we place the remaining 26 net wells on production on behalf of these seven drilling programs.

Based on the formula price as of December 31, 2006, if in the future the drilling program PV−10 value were to exceed $73.9 million, then our maximum obligation would be the formula price of $73.9 million, consisting of obligations of $73.9 million between January 1, 2007 and December 31, 2009.

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 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 re−injected into water disposal 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 $10 million, our portion of which would be approximately $5.0 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.

In 2003, we 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 obtain adequate prices for our gas. 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.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of our seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability and prices of drilling rigs and crews; and
- the availability of leases, license options, farm−outs, other rights to explore and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties.

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 $121 million in 2007. In the future, we intend to finance these capital expenditures through the proceeds public offerings, debt placements 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:

- timely issuance of permits and licenses by governmental agencies;
- the success of our CBM projects in the Washakie Basin;
- the success of our waterflood recovery oil projects in the Wilmington Townlot Unit and the North Wilmington Unit;
- 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;

- 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, 2006, we had an accumulated deficit of $81.8 million and total stockholders' equity of $291.9 million. We have recognized a significant amount of annual net losses in the past. See "Selected Consolidated Financial Data". We may not achieve or sustain profitability or positive cash flows from operating activities in the future.

Our credit facility contains operating restrictions and financial covenants, and we may have difficulty obtaining additional credit.

We will depend on our revolving credit facility for a portion of our future capital needs. Our current revolving credit facility restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. We also are, and expect to continue to be, required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility could result in a default under those facilities, which could cause all of our existing indebtedness to be immediately due and payable.

Our current revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion, based upon projected revenues from the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 75% of the commitments. If the required lenders do not agree on an increase, then the borrowing base will be the lowest borrowing base acceptable to the required number of lenders.

Our credit facility is secured by a pledge of substantially all of our producing natural gas and oil properties assets, is guaranteed by our subsidiary and contains covenants that limit additional borrowings, dividends to nonpreferred shareholders, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common or preferred stock, speculative commodity transactions and other matters. We may not be able to refinance our debt or obtain additional financing, particularly in view of our credit facility's restrictions on our ability to incur additional debt and the fact that substantially all of our assets are currently pledged to secure obligations under the credit facility. The restrictions of our credit facility and our difficulty in obtaining additional debt financing may have adverse consequences on our operations and financial results including:

- our ability to obtain financing for working capital, capital expenditures, our drilling program, purchases of new technology or other purposes may be impaired;
- the covenants in our credit facility that limit our ability to borrow additional funds and dispose of assets may affect our flexibility in planning for, and reacting to, changes in business conditions;

- because our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates;
- any additional financing we obtain may be on unfavorable terms;
- we may be required to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- a substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require us to modify our operations, including by curtailing portions of our drilling program, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing; and
- we may become more vulnerable to downturns in our business or the economy generally.

We may incur additional debt in order to fund our exploration and development activities. 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, natural gas and oil prices and financial, business and other factors, many of which are beyond our control, affect our operations and our future performance. Our senior subordinated notes and senior subordinated secured notes contain restrictive covenants similar to those under our credit facility.

In addition, under the terms of our credit facility, our borrowing base is subject to redeterminations at least semiannually based in part on prevailing natural gas and oil prices. In the event the amount outstanding exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make any required repayment. 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 a portion of our assets.

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

In addition to our credit facility, 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 a debt or 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.

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.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. 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 and lease stipulations in some of the areas where we operate. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs, and 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 seven limited partnerships and participate in two 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 joint 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. 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, 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 water, 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.

A substantial amount 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. Therefore, the success and timing of our drilling and development activities on properties operated by others 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 our interest in the Wilmington Townlot Unit in 1999 and 2005 with no title opinion as to the interests acquired in the Wilmington Townlot Unit, which may ultimately prove to be less than the interests we believe we own. The prior owner 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 Townlot Unit for over 25 years before its sale in 1997. Similarly, when we acquired our interest in the North Wilmington Unit in December 2005, we had no title opinion prepared as to the interests we own in the North Wilmington Unit. The prior owner had owned the North Wilmington Unit for over 15 years, acquired the North Wilmington Unit from Sun Oil Corporation with warranty of title, which had owned unit for over 20 years before its sale in 1990. Losses of title to the Wilmington Townlot Unit and North Wilmington Units may result from title defects or from ownership of a lesser interest than we believe we acquired. 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 may 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.

Some of the factors that cause this fluctuation are:

- the domestic and foreign supply of oil and natural gas;
- the price of foreign imports;
- overall domestic and global economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- variations between product prices at sales points and applicable index prices.

Lower natural gas and oil prices may not only decrease our revenues, 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 exploration, exploitation, 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:

- delays in obtaining drilling permits from applicable regulatory authorities;
- 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.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at December 31, 2006, production will decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and income are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

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

We describe some of our current prospects and our plans to explore those prospects in this annual report. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of natural gas or oil. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. However, the use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling and testing whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in sufficient quantities to recover drilling or completion costs or to be economically viable. If we drill wells in our current and future prospects that are identified as non−economic or dry holes, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any wells is often uncertain and new wells may not be productive.

Our identified drilling location inventories are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi−year drilling activities on our existing acreage. These identified drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

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 proved 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 of 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 a variety of federal, state and local agencies.

If these permits are not issued, or if 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 and California regions, 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:

- the amounts and types of substances and materials that may be released into the environment;
- water discharge and disposal permits for drilling operations;
- drilling permits;
- drilling and operating 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 continues to increase, 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, throughout 2005 and 2006, 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 rises 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 exploration, exploitation, 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 previously restricted shares of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline, or could impair our ability to raise capital through the sale of additional common or preferred stock.

As of December 31, 2006, we had 54,143,054 shares of common stock outstanding, 71,314 shares of common stock were issuable upon conversion of our convertible debt and convertible preferred stock and 2,752,765 shares of common stock were issuable upon exercise of outstanding options and warrants. Our directors and executive officers, hold approximately 4 % of the outstanding shares of our common stock.

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;
- the success of our operating strategy
- 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 may limit your ability to influence the outcome of matters requiring stockholder approval and could discourage our potential acquisition by third parties.

As of March 2, 2007, our executive officers and directors beneficially owned approximately 4% 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.

Failure of the Company's internal control over financial reporting could harm its business and financial results.

The management of Warren is responsible for establishing and maintaining effective internal control over financial reporting. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with accounting principles generally accepted in the United States of America. Internal control over financial reporting includes maintaining records that in reasonable detail accurately and fairly reflect the Company's transactions; providing reasonable assurance that transactions are recorded as necessary for preparation of the financial statements; providing reasonable assurance that receipts and expenditures are made in accordance with management authorization; and providing reasonable assurance that unauthorized acquisition, use or disposition of the Company assets that could have a material effect on the financial statements would be prevented or detected on a timely basis. Because of its inherent limitations, internal control over financial reporting is not intended to provide absolute assurance that a misstatement of the Company's financial statements would be prevented or detected. Failure to maintain an effective system of internal control over financial reporting could limit the Company's ability to report its financial results accurately and timely or to detect and prevent fraud.

Item 1B: Unresolved Staff Comments.

The Company has no outstanding or unresolved SEC staff comments.

Item 3: Legal Proceedings

We are not a party to any material pending legal or governmental proceedings, other than ordinary routine litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

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 2006.

PART II

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

Market Information.

Our common stock is listed on the Nasdaq Global Market under the symbol "WRES".

The following table sets forth, for the period indicated, the high and low sales prices for our common stock as reported by the Nasdaq Global Market:

	Common Stock Price	
	High	Low
Year Ended December 31, 2006		
First Quarter	$ 18.68	$ 13.49
Second Quarter	15.94	11.07
Third Quarter	15.00	11.73
Fourth Quarter	15.18	11.04
Year Ended December 31, 2005		
First Quarter	$ 13.00	$ 8.30
Second Quarter	11.41	8.01
Third Quarter	17.45	10.10
Fourth Quarter	18.19	13.00

On March 2, 2007, the closing sales price for our common stock as reported by Nasdaq was $10.43 per share.

Holders

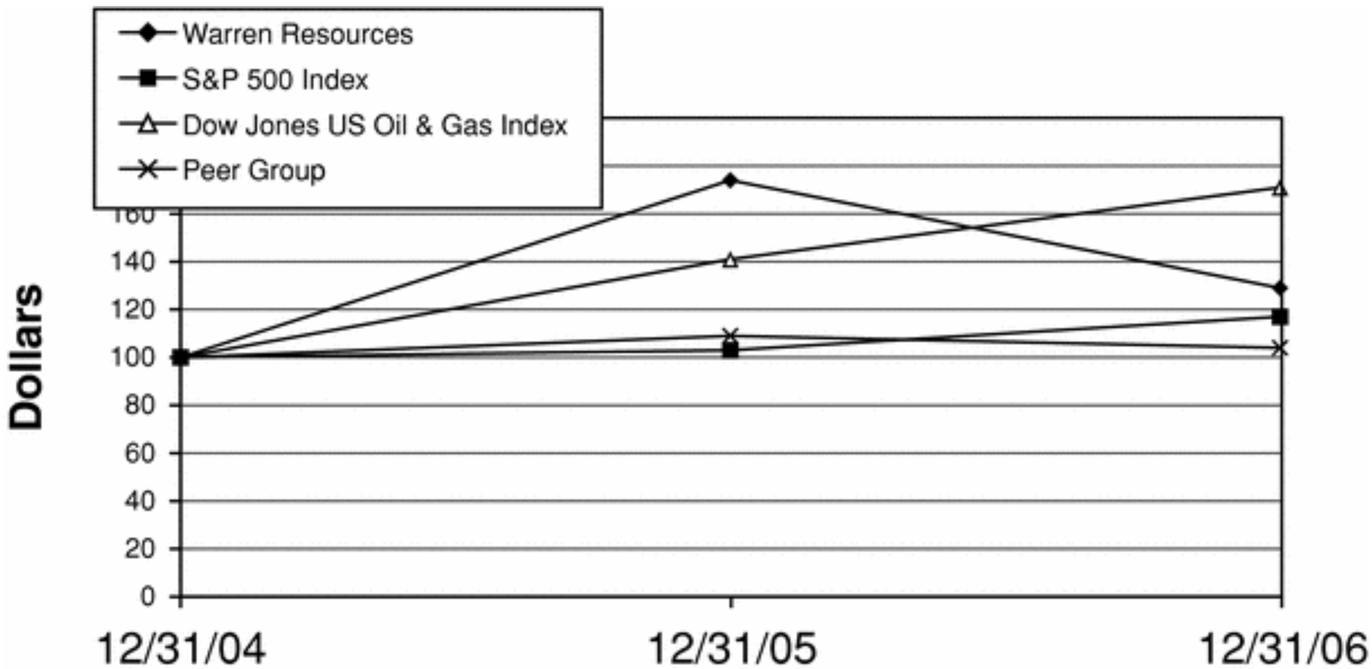
As of March 2, 2007, there were approximately 2,900 holders of our common stock.

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.

Stockholder Return Performance Presentation

The following performance graph compares the performance of the Company’s common stock to the S&P 500 Index, and to the Dow Jones U.S. Oil & Gas Index for the last two years, which is a composite index consisting of 77 U.S. oil and gas companies that includes integrated major oil and gas companies as well as smaller independent U.S. companies. The graph also shows the performance of the Company’s stock for the same two−year period to our peer group of companies consisting of Quicksilver Resources, Inc., Bill Barrett Corp., St. Mary Land & Exploration, Berry Petroleum, Petroleum Development Corporation and Brigham Exploration, which companies have market capitalizations similar to Warren and are primarily involved in domestic U.S. exploration and production. The graph assumes that the value of the investment in the Company’s common stock and each index was $100 at December 31, 2004, and that all dividends were reinvested.



Fiscal Year Ended December 31

	2004	2005	2006
Warren Resources, Inc.	$ 100	$ 174	$ 129
S&P 500 Index	100	103	117
Dow Jones U.S. Oil & Gas Index	100	141	171
Peer Group	100	109	104

Total Return Data Provided by S&P’s Institutional Market Services and Dow Jones & Company, Inc.

Securities Authorized for Issuance Under Compensation Plans

The table below includes information about our equity compensation plans as of December 31, 2006:

	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	765,250	$ 10.83	584,250
2001 Stock Incentive Plan	2,500,000	424,783	7.92	1,312,977
2001 Key Employee Stock Incentive Plan	2,500,000	1,266,750	6.46	1,008,250
Total	6,975,000	2,456,783	8.07	2,905,477

Issuer Purchases of Equity Securities

The Company did not repurchase any of its equity securities in the fourth quarter of 2006.

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, 2006, 2005, 2004, 2003 and 2002 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,				
	2006	2005	2004	2003	2002
	(in thousands, except per share data)				
Consolidated Statement of Operations Data:					
Revenues:					
Oil & gas sales	$ 31,264	$ 13,959	$ 6,454	$ 5,717	$ 593
Turnkey contracts with affiliated partnerships	1,622	9,756	10,530	11,301	5,841
Oil & gas sales from marketing activities	2,330	10,211	6,171	5,621	11,272
Well services	1,029	1,555	1,070	1,168	1,895
Total revenues	36,245	35,481	24,225	23,807	19,601
Costs and operating expenses:					
Production and exploration	13,710	7,296	3,935	3,812	1,326
Turnkey contracts	1,001	11,275	12,932	7,285	4,965
Cost of oil and gas purchased from affiliated partnerships	2,255	10,079	6,028	5,500	11,121
Well services	990	1,147	673	662	839
Depreciation, depletion, amortization and impairment	11,712	3,629	4,075	3,249	9,930
Contingent repurchase obligation	—	—	—	—	(3,065)
General and administrative	9,903	7,476	8,116	4,496	6,278
Retirement of debt expense	—	1,862	—	—	—
Total costs and operating expenses	39,571	42,764	35,759	25,004	31,394
Loss from operations	(3,326)	(7,283)	(11,534)	(1,197)	(11,793)
Other income:					
Interest and other income	4,765	3,302	2,089	1,340	5,258
Interest expense	(399)	(1,685)	(441)	(1,528)	(6,313)
Gain on sale of oil and gas properties	—	203	120	494	4,287
Net gain (loss) on investment	92	961	(44)	21	464
Total other income	4,458	2,781	1,724	327	3,696
Income (loss) before income taxes, minority interest and change in accounting principle	1,132	(4,502)	(9,810)	(870)	(8,097)
Income tax expense (benefit)	93	391	(59)	129	(471)
Income (loss) before minority interest and cumulative change in accounting principle	1,039	(4,893)	(9,751)	(999)	(7,626)
Minority interest	—	(279)	(209)	(112)	—
Net income (loss) before change in accounting principle	1,039	(5,172)	(9,960)	(1,111)	(7,626)
Cumulative effect of change in accounting principle	—	—	—	(88)	—
Net income (loss)	1,039	(5,172)	(9,960)	(1,199)	(7,626)
Preferred dividends and accretion	357	3,774	6,591	4,562	16
Net income (loss) applicable to common stockholders	$ 682	$ (8,946)	$ (16,551)	$ (5,761)	$ (7,642)
Earnings (loss) per share—Basic	$ 0.01	$ (0.23)	$ (0.84)	$ (0.34)	$ (0.44)
Earnings (loss) per share—Diluted	$ 0.01	$ (0.23)	$ (0.84)	$ (0.34)	$ (0.44)
Weighted average shares outstanding—Basic	52,966,115	39,177,816	19,739,048	16,827,857	17,339,869
Weighted average shares outstanding—Diluted	54,511,578	39,177,816	19,739,048	16,827,857	17,339,869

	Year ended December 31,				
	2006	2005	2004	2003	2002
	(in thousands, except per share data)				
Consolidated Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 10,821	$ (10,348)	$ (4,507)	$ 5,278	$ (6,101)
Investing activities	(88,182)	(54,654)	(29,033)	(13,524)	5,317
Financing activities	5,751	79,714	108,931	9,591	1,045

	As of December 31,				
	2006	2005	2004	2003	2002
Balance Sheet Data:					
Cash and cash equivalents	$ 43,022	$ 114,632	$ 99,921	$ 24,529	$ 23,184
Total assets	323,859	320,764	246,911	151,054	108,262
Total long−term debt (including current maturities)	9,520	8,906	50,038	49,916	56,202
Stockholders’ equity	291,884	278,040	157,569	56,394	7,002

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 (“CBM”) properties located in the Rocky Mountain region and on our waterflood oil recovery programs in the Wilmington field within the Los Angeles Basin of California. As of December 31, 2006, we owned natural gas and oil leasehold interests in approximately 272,241 gross (152,596 net) acres, 92% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains. Our total net proved reserves are located on less than 10% 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 programs and retain an interest in the wells. Historically, a substantial portion of our revenue was attributable to these turnkey drilling services.

For fiscal years 2007 and later, Warren will not recognize revenue from turnkey drilling services. As of December 31, 2006, we have performed our obligations under the turnkey drilling contracts. As a result, we have no deferred income liability as of December 31, 2006. Our future revenue growth is primarily dependent on our ability to increase our oil and gas reserves and production.

The schedule below reflects revenue and expense from natural gas and oil sales and from turnkey contracts for the years ended December 31, 2006 and 2005.

	2006	2005
Oil and gas sales	$ 31,264,379	$ 13,959,097
Production and exploration expense	13,709,966	7,295,520
Depreciation, depletion, amortization and impairment	11,206,490	3,397,275
Gross margin	$ 6,347,923	$ 3,266,302
Turnkey contract revenue with affiliated partnerships	$ 1,621,462	$ 9,756,209
Turnkey contract expense	1,001,397	11,275,348
Depreciation, depletion, amortization and impairment	76,711	103,216
Gross margin	$ 543,354	$ (1,622,355)

Liquidity and Capital Resources

Our cash and cash equivalents decreased $71.6 million during 2006. This resulted from cash used in investing activities of $88.2 million. This was offset by cash provided by operating activities of $10.8 million and cash provided by financing activities of $5.8 million.

Cash used in investing activities of $88.2 million results from $88.9 million for expenditures on oil and gas properties and equipment offset by the release of $0.7 million in U.S. Treasury Bonds relating to the acquisition of certain drilling programs and the redemption of debentures. Cash provided by operating activities of $10.8 million primarily relates to oil and gas operations. Cash provided by financing activities of $5.8 million primarily results from proceeds received from the exercise of stock options and warrants.

During the first quarter of 2006, effective as of the last drilling partnership distribution date in the fourth quarter of 2005 and closing on March 31, 2006, the investor partners of the 1998 drilling partnerships voted to approve the sale of all of the oil and gas assets of the drilling partnerships to us. The aggregate purchase price was $8.2 million. As a result, net of our interest, the Company issued 383,072 shares of restricted common stock and paid $2.7 million in cash in exchange for both producing and non−producing properties. The number of shares issued was determined based upon a 20% discount from the weighted average sales price for Warren’s publicly traded common stock for the forty−five (45) calendar days ending March 31, 2006. The Company recorded the transaction based on the undiscounted weighted average price of its common stock for the forty−five (45) calendar days ending March 31, 2006. The Company received oil and gas properties having a PV−10 value of approximately $7.6 million as determined by Williamson Petroleum Consultants, Inc., as well as unproved properties.

Additionally during the first quarter of 2006, we purchased for cash the remaining minority oil and gas interests not already owned by Warren from the drilling program LLC’s originally formed between 1994 and 1997 based upon their PV−10 value as determined by Williamson Petroleum Consultants, Inc., independent petroleum engineers. We paid an aggregate cash purchase price of $1.1 million. The remaining minority interest relating to these partnerships was recorded as a reduction in the cost basis of the assets acquired.

On November 20, 2006, Warren entered into a five year, $150 million credit agreement with JP Morgan Chase Bank (the “Credit Facility”). The Credit Facility provides for a revolving credit facility up to the lesser of (i) the borrowing base (ii) $150 million and (iii) the draw limit requested by the Company. The Credit Facility matures on November 15, 2011. It is secured by substantially all of our assets. The borrowing base will be determined by the lenders at least semi−annually on each April 1 and October 1, beginning April 1, 2007 and is based in part on the proved reserves of the Company. Interest payments are made quarterly in arrears. The initial borrowing base is $40 million. The company is subject to certain covenants under the terms of the Credit Facility which include, but are not limited to the maintenance of the following financial ratios (1) minimum current ratio of 1.0 to 1.0 and (2) a maximum total net debt to annualized consolidated EBITDAX (as defined by the Credit Facility) of 3.5 to 1.0.

Depending on the current level of borrowing base usage, the annual interest rate on each base rate borrowing under the Credit Facility will be at our option either: (a) the higher of (i) the Agent’s prime rate of interest announced from time to time, or (ii) the Federal Funds rate most recently determined by the Agent, plus ½% per annum, plus an applicable margin that ranges from 0.25% to 1.0%, or (b) Eurodollar Loan rate plus an applicable margin that ranges from 1.25% to 2%.

The Company had net income of $0.7 million (after preferred dividends and accretion of $0.4 million) for 2006, as compared to a net loss of $8.9 million (including preferred dividends of $3.8 million) for 2005. At December 31, 2006, current assets exceeded current liabilities by approximately $29.5 million. We expect our cash and cash equivalents, cash flows from operating activities and bank financings to be sufficient to fund our operations for more than the next twelve months.

At December 31, 2006, we had approximately 2.0 million vested outstanding stock options issued under our stock based equity compensation plans. Of the total 2.0 million outstanding vested options, only 15,000 options had exercise prices above the closing market price ($11.72) of our common stock on December 31, 2006. If the options with exercise prices below the closing market price on December 31, 2006 are exercised by the holders, we would receive $13.3 million in cash.

2007 Capital Expenditure Program

Our capital expenditure budget for 2007 is $121 million, which includes participation in the drilling of 142 gross (99 net) wells. At the present time, we are concentrating our drilling activities in California and Wyoming. We have two California projects in the Wilmington field, the Wilmington Townlot Unit (WTU) and the North Wilimington Unit (NWU). Additionally, we have three exploratory projects in Wyoming, the Atlantic Rim and Pacific Rim projects in the Washakie Basin and one in the Hanna Basin. We are planning to drill 60 gross (59 net) producing and injecting wells in California with capital expenditures estimated at $68 million. We plan to drill 34 gross (33 net) wells in the WTU with estimated capital expenditures of $50 million. We plan to recomplete or drill 26 gross (26 net) wells in the NWU with estimated capital expenditures of $18 million. Also, we plan to drill 82 gross (39 net) producing and injecting wells in Wyoming with estimated capital expenditures of $45 million. We plan to drill 80 gross (38 net) wells in the Atlantic Rim project with estimated capital expenditures of $38 million. We plan to drill 2 gross (1 net) wells in the Pacific Rim project with estimated capital expenditures of $5 million. Lastly, we are currently drilling one exploratory well in Wyoming with estimated net 2007 capital expenditures of $2.0 million. 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.

Our estimated total proved reserves as of December 31, 2006 are approximately 349 billion cubic feet of gas equivalent (Bcfe) with a PV−10 value of approximately $609 million using December 31, 2006 oil and gas pricing. Approximately 82% of our estimated net proved reserves are undeveloped.

Compared with the development of our CBM properties, we anticipate that development of our oil properties in California could have a more immediate impact on our cash flows. We also anticipate that we will be able to conduct drilling operations in California 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.

Stock based Equity Compensation Plan Information

At December 31, 2006, we had approximately 2.0 million vested outstanding stock options issued under our stock based equity compensation plans. Of the total 2.0 million outstanding vested options, 2.0 million had exercise prices below the closing market price $11.72 of our common stock on December 31, 2006. If such options are exercised by the holders, we will receive the exercise price in cash. The following table provides information with respect to shares of our common stock that may be issued under vested stock options whose exercise price was less than our closing stock price on December 31, 2006.

Exercise Price of Outstanding Vested Options	Number of Securities to be Issued Upon Exercise of Vested Outstanding Options	Proceeds to be Received Upon Exercise of Vested Outstanding Options
$4.00	672,783	$ 2,691,132
$7.00	609,500	4,266,500
$9.05	689,000	6,235,450
$11.00	10,000	110,000
	1,981,283	$ 13,303,082

For additional detail about our stock based equity compensation plans, see "Executive Compensation—Employee Benefit Plans" under Item 11 and as incorporated by reference from our Proxy Statement on Form 14A.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. Below, we provide expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our consolidated financial statements. See Notes to the Consolidated Financial Statements for a discussion of additional accounting policies and estimates made by management.

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 recorded 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.

Well services revenue is recognized when services are performed.

New Accounting Pronouncement

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements.* SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a balance sheet (iron curtain) approach in assessing materiality and provides for a one−time cumulative effect transition adjustment. SAB No. 108 is effective for our fiscal year 2006 annual financial statements. The adoption of SAB No. 108 did not have a material impact on the Company's consolidated financial position or results of operations.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 will not have a material impact on the Company's consolidated financial position or results of operations.

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in the company's Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, "the Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. Unrealized gains and losses on items for which the fair value option has been elected will be recognized in earnings at each subsequent reporting date. SFAS 159 is effective for us January 1, 2008. We are evaluating the impact that the adoption of ASAF No. 159 will have on our consolidated financial statements.

Results of Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Oil and gas sales. Revenue from oil and gas sales increased $17.3 million to $31.3 million during 2006, a 124% increase compared to 2005. This increase in production resulted from significantly increasing our drilling activity in the Wilmington Townlot Unit ("WTU") in southern California. Additionally, this increase results from acquiring the North Wilmington Unit ("NWU") which is adjacent to the WTU. Prior to July 2005, all wells were syndicated to our drilling partnerships which resulted in lower working interest percentages allocated us. Net oil production for 2006 and 2005 was 456 thousand barrels of oil ("Mbbls") and 148 Mbbls, respectively. Net gas production for 2006 and 2005 was 1.1 billion cubic feet of gas ("Bcf") and 1.1 Bcf, respectively. The average realized price per barrel of oil for 2006 and 2005 was $55.36 and $45.75, respectively. Additionally, the average realized price per Mcf of gas for 2006 and 2005 was $5.73 and $6.71, respectively.

Production & exploration. Production and exploration expense increased $6.4 million during 2006 to $13.7 million, an 88% increase compared to 2005. This increase resulted from a 124% increase in production as described above. Production and exploration expense was $19.68 per barrel of oil in 2006 compared to $25.56 per barrel of oil in 2005. Production and exploration expense was $4.76 per mcf of gas in 2006 compared to $3.13 per mcf of gas in 2005. Production and exploration expense per barrel of oil decreased during 2006 because of higher production levels and a reduction in repair and maintenance costs during 2006. Production and exploration expense per mcf of gas increased during 2006 because of operating expenses relating to CBM wells that were drilled or acquired during the year.

Turnkey contract revenue and expenses. Turnkey contract revenue decreased $8.1 million during 2006 to $1.6 million, an 83% decrease compared to 2005. Additionally, turnkey contract expense decreased $10.3 million during 2006 to $1.0 million, a 91% decrease compared to 2005. The drilling activity on behalf of the drilling programs was less active during 2006 compared to 2005.

The Company realized a gain from turnkey activities before allocation of depreciation and interest expense of $0.6 million for 2006 compared to a loss of $1.5 million for 2005. The gain from turnkey activities during 2006 resulted from drilling wells more economically during this period.

Oil and gas sales and costs from marketing activities. Oil and gas sales from marketing activities decreased $7.9 million during 2006 to $2.3 million, a 77% decrease compared to 2005. Cost of oil and gas marketing activities decreased $7.8 million during 2006 to $2.3 million, a 78% decrease compared to 2005. The decrease results from acquiring the assets in our drilling partnerships formed between 1994 and 1998. Gas production from the wells in the drilling partnerships in which we earn a marketing fee for the years ended December 31, 2006 and 2005 was 332 Mmcfe and 1,800 Mmcfe, respectively. The average price per Mcfe during 2006 and 2005 was $6.79 and $5.60, respectively. The gross profit from marketing activities for 2006 was $75 thousand compared to $132 thousand in 2005.

Well services activities. Well services revenue decreased $0.5 million during 2006 to $1.0 million, a 34% decrease compared to 2005. Well services expense decreased $0.2 million during 2006 to $1.0 million. The decreases in well services revenue and expense results from drilling less wells and administrating less wells on behalf of the drilling programs which were recently acquired. Gross profit from well services activities was $39 thousand and $0.4 million for 2006 and 2005, respectively.

Net gain on investments. Net gain on investments was $0.1 million for 2006. Net gain on investments was $1.0 million for 2005. Primarily, investments represent zero coupon U.S. treasury bonds. Fluctuations in net gain or loss on investments resulted from a decrease in invested assets during 2006.

Interest and other income. Interest and other income increased $1.5 million in 2006 to $4.8 million, a 44% increase compared to 2005. This represents an increase in interest earned on idle cash balances.

Depreciation, Depletion, Amortization and Impairment. Depreciation, depletion, amortization and impairment expense increased $8.1 million for 2006 to $11.7 million, a 223% increase compared to last year. This increase resulted from $4.6 million of impairment expense in 2006 compared to $0.2 million in 2005. The Company recorded impairment expense primarily related to its Pacific Isle Unit in the Pacific Rim Project in Wyoming. Additionally, depletion rates increased during 2006 compared to 2005 as a result of production increases during this period.

General and administrative expenses. General and administrative expenses increased $2.4 million during 2006 to $9.9 million, a 32% increase compared to last year. This reflects a decrease in the allocation of certain general and administrative expenses to turnkey expenses during 2006. Additionally, this results from an increase in personnel as a result of increased drilling activities. Lastly, compensation expense relating to the issuance and vesting of stock options were $0.6 million in 2006 compared to $−0− in 2005.

Interest expense. Interest expense decreased $1.3 million during 2006 to $0.4 million, a 76% decrease compared to last year. The Company reduced long−term debt by approximately $44 million during 2005. As a result, interest expense decreased significantly.

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, 2006, we had a net operating loss carryforward of approximately $99 million. As of December 31, 2006, we have provided a 100% valuation allowance on our net deferred tax assets. Our net operating loss carryforwards expire in 2012 and subsequent years.

Results of Operations

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

Oil and gas sales. Revenue from oil and gas sales increased $7.5 million to $14.0 million during 2005, a 116% increase compared to 2004. This increase resulted from our acquisition of substantially all of the remaining working interests in the Wilmington Townlot Unit in California. Additionally, this increase reflects drilling wells for our own account. Prior to the third quarter of 2005, all wells were syndicated to our drilling programs. Net production for 2005 and 2004 was 1,959 Bcfe and 1,226 Bcfe, respectively. Additionally, the average realized price per Mcfe for 2005 and 2004 was $7.13 and $5.26, respectively.

Production & exploration. Production and exploration expense increased $3.3 million during 2005 to $7.3 million, an 85% increase compared to 2004. This increased resulted from an increase in lease operating expenses related to the Wilmington Townlot Unit in California. The Company has incurred significant start up repair and maintenance costs associated with the implementation of our drilling plan. Additionally, increases in production and exploration expense result from increases in oil and gas production.

Turnkey contract revenue and expenses. Turnkey contract revenue decreased $0.8 million during 2005 to $9.8 million, a 7% decrease compared to 2004. Additionally, turnkey contract expense decreased $1.7 million during 2005 to $11.3 million, a 13% decrease compared to 2004. The drilling activity on behalf of the drilling programs was less active during 2005 compared to 2004.

Loss from turnkey activities before allocation of depreciation and interest expense was $1.5 million for 2005 compared to a loss of $2.4 million for 2004. The loss from turnkey activities during 2005 and 2004 results from increased drilling costs.

Oil and gas sales and costs from marketing activities. Oil and gas sales from marketing activities increased $4.0 million during 2005 to $10.2 million, a 65% increase compared to 2004. Cost of oil and gas marketing activities increased $4.1 million during 2005 to $10.1 million, a 67% increase compared to 2004. These increases resulted from increases in oil and gas production from the wells in the drilling programs in which we earn a marketing fee. This production was 1.8 Bcfe and 1.4 Bcfe for 2005 and 2004, respectively. The average price per Mcfe during 2005 and 2004 was $5.60 and $4.45, respectively.

The gross profit from marketing activities for 2005 was $132 thousand compared to $143 thousand in 2004.

Well services activities. Well services revenue increased $0.5 million during 2005 to $1.6 million, a 45% increase compared to 2004. Well services expense increased $0.5 million during 2005 to $1.1 million. The increases in well services revenue and expense results from a joint venture between Anadarko Petroleum Corporation and Warren that commenced during 2005. Under this joint venture, we charge a fee for the use of our jointly owned compression facilities and sales lines.

Gross profit from well services activities was $0.4 million for 2005 and 2004.

Net gain on investments. Net gain on investments was $1.0 million for 2005. Net loss on investments was $42 thousand for 2004. Primarily, investments represent zero coupon U.S. treasury bonds. 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 $1.2 million in 2005 to $3.3 million, a 58% increase compared to 2004. This represents an increase in interest earned on idle cash balances.

Depreciation, Depletion, Amortization and Impairment. Depreciation, depletion, amortization and impairment expense decreased $0.5 million for 2005 to $3.6 million, a 12% decrease compared to last year. This decrease results from $2.3 million of impairment expense in 2004 compared to $0.2 million in 2005. The decrease was offset by an increase in depletion expense of $1.6 million resulting from an increase in oil and gas production from the Wilmington Townlot Unit in California and an increase in the cost basis of the Wilmington Townlot Unit.

General and administrative expenses. General and administrative expenses decreased $0.6 million during 2005 to $7.5 million, an 8% decrease compared to 2004. This decrease results from a litigation accrual of $1.8 million recorded during the fourth quarter of 2004. The decrease was offset by an increase of $1.0 million in general and administrative expense resulting from the allocation of less general and administrative expense to turnkey activities during 2005. Additionally, the decrease was offset by an increase in the number of employees.

Interest expense. Interest expense increased $1.3 million during 2005 to $1.8 million, a 255% increase compared to last year. Interest expense increased significantly during 2005 because we are no longer capitalizing interest costs related to the Wilmington Townlot Unit in California. The Company capitalized interest totaling $1.7 million during 2005 compared to $5.9 million during 2004.

Retirement of debt. Retirement of debt expense was $1.9 million during 2005. There was no retirement of debt expense in 2004. This expense represents a premium paid on redemption of the debentures and the write off of unamortized deferred offering costs associated with the early redemption of debentures during 2005.

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, 2005, we had a net operating loss carryforward of approximately $84 million. As of December 31, 2005, we had provided a 100% valuation allowance on our net deferred tax assets. Our net operating loss carryforwards expire in 2012 and subsequent years.

Debentures

As of December 31, 2006, we had $2.5 million of convertible secured debentures that are convertible into our common shares. Further, all convertible secured debentures are callable by us if the average bid price of our public traded common shares traded 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 100% of par value plus accrued interest.

The principal of the convertible 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 table below reflects the outstanding convertible secured 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 2007. The conversion prices listed below will increase in the future.

Debentures (in thousands, except for conversion prices)	Outstanding at December 31, 2006	Conversion Price as of December 31, 2006	Fair Market Value of U.S. Treasuries	Estimated Debenture Interest for 2007
12% Secured Fund Debentures due December 31, 2020	$ 1,390,000	$ 35.00	$ 709,790	$ 166,800
12% Secured Fund Debentures due December 31, 2022	1,106,000	35.00	508,760	132,720
	$ 2,496,000		$ 1,218,550	$ 299,520

Preferred Stock

As of December 31, 2006, we had 272,000 shares of convertible preferred stock issued and outstanding. During 2006, 268,508 shares of our convertible preferred stock converted into common shares on a 1 to 0.75 basis and 11,361 shares of preferred stock converted into common shares on a 1 to 0.50 basis. Dividends and accretion on preferred shares totaled $0.4 million and $3.8 million for the years ended December 31, 2006 and 2005, respectively.

All of our outstanding preferred stock has a dividend equal to 8% per annum, payable to the extent legally available quarterly in arrears, and has a liquidation preference of $12.00 per share. Any accrued but unpaid dividends shall be cumulative and paid upon liquidation, optional redemption or conditional repurchase. No dividends may be paid on the common stock as long as there are any accrued and unpaid dividends on the preferred stock. Commencing July 1, 2006 and thereafter, at the election of the holder of our convertible preferred stock, each share of preferred stock is convertible into 0.50 share of common stock.

The conversion rate for our convertible preferred stock is subject to adjustment in the event of:

- the issuance of common stock as a dividend or distribution on any class of our capital stock;
- the combination, subdivision or reclassification of the common stock; or
- the distribution to all holders of common stock of evidences of indebtedness or assets, including securities issued by third parties, but excluding cash dividends or distributions paid out of surplus.

Commencing seven years after their respective date of issuance, the preferred stock may be redeemed by the holders at a redemption price equal to the liquidation value of $12.00 per share, plus accrued but unpaid dividends, if any. At December 31, 2006, there were 218,920 preferred shares outstanding that the Company may be required to redeem during the year ended December 31, 2010, and thereafter, and 53,080 preferred shares outstanding that the Company may be required to be redeemed during the year ended December 31, 2011 and thereafter.

Upon receipt of a redemption election, we, at our option, shall either:

- pay the holder cash in an amount equal to $12.00 per convertible preferred share, subject to adjustment for stock splits, stock dividends or stock exchanges, plus accrued and unpaid dividends, to the extent that we have funds legally available for redemption, or
- issue to the holder shares of common stock in an amount equal to 125% of the cash redemption price and any accrued and unpaid dividends, based on the average of the closing sale prices of our common stock for the 30 trading days immediately preceding the date of the receipt of the written

redemption election by the holder, as reported by the Nasdaq Stock Market, or by any exchange or electronic OTC listing service on which the shares of common stock are then traded. In the event that we elect to pay the Redemption Price in kind with our common stock, for the 272,000 shares of preferred stock representing $3.3 million of Redemption Price value, notwithstanding the market price of our common stock, we shall not issue to the redeeming preferred stockholders less than their proportionate share of 272,000 shares of our shares of common stock, nor be obligated to issue more than 408,000 shares of our common stock in full satisfaction of the redemption, subject to adjustment for stock splits, stock dividends and stock exchanges.

If we are not listed on an exchange or our common stock has no trading volume, upon redemption the Board shall determine the fair market value of the common stock.

If the closing sale price of our publicly traded common stock as reported by the Nasdaq Stock Market, or any exchange or electronic OTC listing service on which the shares of common stock are then traded, exceeds 133% of the conversion price then in effect for the preferred stock for at least 10 trading days during any 30−day period, we, at our option, may either:

- redeem the preferred stock in whole or in part, at a redemption price of $12.00 per share plus accrued and unpaid dividends, or
- convert the preferred stock, plus any accrued and unpaid dividends, into common stock at the then applicable conversion rate, based on the average closing sale prices of our common stock for the 30 trading days immediately preceding the date fixed for redemption.

In addition, the preferred stock, plus accrued and unpaid dividends, shall be converted into common stock at the then applicable conversion rate upon the vote or written consent of the holders of 66 2/3% of the then outstanding preferred stock, voting together as a class.

Accordingly, if the holders of any of the then−remaining outstanding shares of our preferred stock request redemption commencing in 2009 and thereafter and we elect to pay the Redemption Price for the preferred stock in cash, we would need capital of $12.00 per share, plus the amount of any accrued but unpaid dividends, which funds may not be available and the payment of which could have a material adverse effect on our financial liquidity and results of operation. Alternatively, if we elect to pay the Redemption Price for the preferred stock commencing in 2009 and thereafter with shares of our common stock, such issuance could materially increase the number of our shares of common stock then outstanding and be dilutive to our earnings per share, if any.

Contractual Obligations

The contractual obligations table below assumes the maximum amount is tendered each year. 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 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.

	Payments due by period				
Contractual Obligations As of December 31, 2006	**Total**	**Less Than 1 Year**	**1−3 Years**	**4−5 Years**	**More Than 5 Years**
Debentures	$ 2,496,000	$ 249,600	$ 426,816	$ 345,721	$ 1,473,863
Drilling Commitments	2,953,852	2,953,852	—	—	—
Leases	387,720	212,909	147,015	27,796	—
Total	$ 5,837,572	$ 3,416,361	$ 573,831	$ 373,517	$ 1,473,863

The contractual obligation schedule above does not reflect $2.5 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 $1.2 million at December 31, 2006.

The Company has a contract with Nabors Well Services Co. (Contractor) for drilling wells in California that expires September 1, 2007. The contract provides for an operating rate of $22,490 per day. In the event of early termination, a shortfall charge of $8,922 per day is incurred for each day prior to the initial termination date, which is limited to a maximum of $1,500,000.

The Company has a contract with Ensign United States Drilling, Inc. (Contractor) for drilling wells in California that expires August 18, 2007. The contract provides for an operating rate of $12,640 per day. In the event of early termination, the company will incur demobilization costs of $23,000 plus actual costs incurred by the contractor for removing and returning the rig to the contractor’s yard, for a maximum of $1,453,852 in 2006.

Off−Balance Sheet Arrangements

Under the terms of our drilling programs formed from 1999 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. The tender rights were included to make such programs more attractive to potential investor partners, thereby enabling the Company to obtain more capital to drill more oil and gas wells. 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, 2006, based on the December 31, 2006 reserve reports of the respective drilling programs, the aggregate PV−10 value of the assets in these programs is $13.0 million. Because this PV−10 value is less than the formula price of $73.9 million at December 31, 2006, the maximum repurchase price obligation at December 31, 2006 was $13.0 million. This PV−10 value would be higher if current prices for crude oil and natural gas were to increase when we place the remaining 26 net wells on production on behalf of these five 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. There are no known events that would result in termination of the material benefits of our off−balance sheet arrangements except for a decrease in oil and gas pricing that occurs after an acquisition. The only material off−balance sheet benefit of this arrangement is the acquisition of proved reserves. To the extent that we acquire interests for their PV−10 value based on this arrangement, and declining oil and natural gas prices, or other factors, render those interests less valuable, a material reduction in the benefit of this arrangement to the Company would occur.

The table below presents the projected timing of our maximum potential repurchase commitment associated with these programs as of December 31, 2006:

	Amount of repurchase commitment per period				
	Less Than 1 Year	1−3 Years	4−5 Years	More Than 5 Years	Total
			(in thousands)		
Maximum potential repurchase commitment(1)	$ 1,887	$ 11,130	—	—	$ 13,017

(1) Based on the partnership reserves taken from the Williamson partnership reserve report as of December 31, 2006 and using pricing at that date. This report does not include reserves for the 26 net wells drilled and waiting to be placed on production.

Commencing January 1, 2007, we may be obligated to commence purchasing drilling program interests at their PV−10 value. As a result, the following factors may affect the liquidity and capital resources of the Company:

- An increase in the price of oil and natural gas, or an increase in the amount of proved reserves (from the 26 net wells drilled and waiting to be placed on production, or from other factors) may increase the PV−10 value of the drilling programs and, as a result, increase the price of our repurchase. After the acquisition of any drilling program interests, oil and natural gas prices may decline, resulting in a decline in the expected future net cash flow or the fair market value of the assets acquired in the repurchase and a possible recording of impairment expense.
- If our existing capital is inadequate to fund the repurchase of drilling program interests, we may be unable to obtain financing, or obtain financing on terms acceptable to us, to purchase the drilling program interests at their PV−10 value.

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 and other long−term liabilities. The carrying amounts of cash and cash equivalents, U.S. treasury bonds and other long−term liabilities, approximate fair market value due to the highly liquid nature of these short−term instruments or they are reported at fair value.

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.

Item 8: Financial Statements and Supplementary Data

See Report of independent Registered Public Accounting Firm and Audited Financial Statements at Item 15.

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

None.

Item 9A: Controls and Procedures

Disclosure Controls and Procedures.

We maintain controls and procedures designed to ensure that information required to be disclosed in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Evaluations have been performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a—15(e) and 15d—15(e) of the Exchange Act). Based upon those evaluations, management, including the Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were adequate and effective as of December 31, 2006 to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Exchange Act are recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Pursuant to the evaluation performed in connection with the filing of this Amendment, management has confirmed that our disclosure controls and procedures were adequate and effective as of December 31, 2006 and continue to be adequate and effective as of the date of this filing.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realties that judgments in decision−making can be faulty and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives and the Chief Executive Officer and the Chief Financial Officer, as of December 31, 2006, have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. As defined in Exchange Act Rule 13a−15(f), internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we carried out an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2006 based on the criteria in "Internal Control − Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based upon this evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Grant Thornton LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10−K, has also audited our management's assessment of the effectiveness of the Company's internal control over financial reporting and the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 as stated in their report included herein.

Changes in Internal Control over Financial Reporting.

There were no changes in internal control over financial reporting that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting

Item 9B: Other Information.

Not applicable.

PART III

Item 10: Directors, Executive Officers and Corporate Governance

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 May 16, 2007 (to be filed with the SEC within 120 days after the end of the Company's fiscal year ended December 31, 2006) 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 and Related Stockholder Matters

Information required by this item will be contained in the Proxy Statement under the caption "Securities Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters" and is incorporated herein by reference.

Item 13: Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be contained in the Proxy Statement under the caption "Certain Transactions" and "Corporate Governance" 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

(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(13)	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(13)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(8)	Form of Class A Common Stock Warrant
4.3(8)	Form of Class B Common Stock Warrant
4.4(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.
4.5(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

Exhibit No.	Description
4.6(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
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(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Norman F. Swanton
10.9(9)	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin
10.10(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Timothy A. Larkin
10.11(15)	Employment Agreement dated as of July 1, 2005, between the Registrant and Lloyd Davies
10.12(15)	Employment Agreement executed on June 17, 2005, between the Registrant and David E. Fleming
10.13(10)	Employment Agreement dated January 1, 2004, between the Registrant and Ellis G. Vickers
10.14(1)	Form of Indemnification Agreement
10.15(1)	Form of Partnership Production Marketing Agreement
10.16(4)	Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc.
10.17(4)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.18(4)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.
10.19(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.
10.20(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.

Exhibit No.	Description
10.21(14)	Asset Purchase Agreement dated December 9, 2005 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc. and Global Oil Production, LLC and Wilmington Management, LLC
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 Grant Thornton LLP
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†	Certification of CEO and CFO pursuant to Section 1350

(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.

(13) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2004, filed on March 17, 2005.

(14) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed December 12, 2005.

(15) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed June 17, 2005.

† 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 Norman F. Swanton	*President, Chief Executive Officer, Director and Chairman*
By	/s/ TIMOTHY A. LARKIN Timothy A. Larkin	*Executive Vice President, Chief Financial Officer, and Principal Accounting Officer*

Dated: March 6, 2007

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 Norman F. Swanton	President, Chief Executive Officer, Director and Chairman	March 6, 2007
/s/ TIMOTHY A. LARKIN Timothy A. Larkin	Executive Vice President, Chief Financial Officer and Principal Accounting Officer	March 6, 2007
/s/ ANTHONY COELHO Anthony Coelho	Director	March 6, 2007
/s/ LLOYD DAVIES Lloyd Davies	Director	March 6, 2007
/s/ DOMINICK D'ALLEVA Dominick D'Alleva	Director	March 6, 2007
/s/ THOMAN NOONAN Thomas Noonan	Director	March 6, 2007
/s/ MICHAEL R. QUINLAN Michael R. Quinlan	Director	March 6, 2007
/s/ CHET BORGIDA Chet Borgida	Director	March 6, 2007
/s/ LEONARD DECECCHIS Leonard Dececchis	Director	March 6, 2007

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Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Warren Resources, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, appearing under item 9A, that Warren Resources, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control − Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control − Integrated Framework* issued by COSO. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control − Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2006 and our report dated March 5, 2007 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 5, 2007

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Warren Resources, Inc.

We have audited the accompanying consolidated balance sheets of Warren Resources, Inc. and Subsidiaries (the “Company”) as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders’ equity and cash flows for each of the three years in the period ended December 31, 2006. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Warren Resources, Inc. and Subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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, 2006, the Company adopted Statement of Financial Accounting Standards No. 123 (R), *Accounting for Stock−Based Compensation.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company’s internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control − Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 5, 2007 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting and management’s assessment thereon.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 5, 2007

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED BALANCE SHEETS
December 31,

	2006	2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 43,021,884	$ 114,632,099
Accounts receivable—trade	5,949,369	3,945,862
Accounts receivable from affiliated partnerships	34,890	118,356
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $98,884 in 2006 and $96,959 in 2005)	121,855	125,771
Other current assets	3,309,692	2,356,583
Total current assets	52,437,690	121,178,671
Other Assets		
Oil and gas properties—at cost, based on successful efforts method of accounting, net of accumulated depreciation, depletion, amortization and impairment	260,500,325	185,904,194
Property and equipment—at cost, net	1,751,146	559,612
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $889,953 in 2006 and $1,387,910 in 2005)	1,096,695	1,821,181
Deferred bond offering costs, net of accumulated amortization of $272,853 in 2006 and $253,537 in 2005	258,383	277,700
Goodwill	3,430,246	3,430,246
Other assets	4,384,772	7,592,799
Total other assets	271,421,567	199,585,732
	$ 323,859,257	$ 320,764,403
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current maturities of debentures	$ 249,600	$ 260,600
Current maturities of other long−term liabilities	257,028	325,994
Accounts payable and accrued expenses	22,455,043	25,042,379
Deferred income—turnkey drilling contracts with affiliated partnerships	—	1,765,829
Total current liabilities	22,961,671	27,394,802
Long−Term Liabilities		
Debentures, less current portion	2,246,400	2,345,400
Other long−term liabilities, less current portion	6,766,868	5,974,493
	9,013,268	8,319,893
Minority Interest	—	7,009,634
Commitments and Contingencies		
Stockholders' Equity		
8% convertible preferred stock—$.0001 par value; authorized, 10,000,000 shares; issued and outstanding, 272,000 shares in 2006 and 652,366 shares in 2005 (aggregate liquidation preference $3,264,000 in 2006 and $7,828,032 in 2005)	3,252,897	7,629,622
Common stock—$.0001 par value; authorized, 100,000,000 shares; issued, 54,143,054 shares in 2006 and 52,738,384 shares in 2005	5,414	5,274
Additional paid−in capital	371,035,151	353,714,161
Accumulated deficit	(81,822,011)	(82,861,220)
Accumulated other comprehensive income, net of applicable income taxes of $92,000 in 2006 and $185,000 in 2005	140,922	280,292
	292,612,373	278,768,129
Less common stock in Treasury—at cost; 632,250 shares in 2006 and 2005	728,055	728,055
Total Stockholders' Equity	291,884,318	278,040,074
	$ 323,859,257	$ 320,764,403

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF OPERATIONS
Year ended December 31,

	2006	2005	2004
Revenues			
Oil and gas sales	$ 31,264,379	$ 13,959,097	$ 6,454,334
Turnkey contracts with affiliated partnerships	1,621,462	9,756,209	10,529,883
Oil and gas sales from marketing activities	2,329,945	10,210,681	6,171,338
Well services, 78%, 70%, and 84% with affiliated partnerships, respectively	1,029,442	1,554,760	1,070,004
Net gain (loss) on investments	92,191	960,995	(42,916)
Interest and other income	4,765,303	3,302,034	2,088,994
Gain on sale of unproved oil and gas properties	—	203,487	120,193
	41,102,722	39,947,263	26,391,830
Expenses			
Production and exploration	13,709,966	7,295,520	3,935,137
Turnkey contracts	1,001,397	11,275,348	12,932,124
Cost of marketed oil and gas purchased from affiliated partnerships	2,254,820	10,078,848	6,028,727
Well services	990,033	1,146,590	672,933
Depreciation, depletion, amortization and impairment	11,711,640	3,628,610	4,075,496
General and administrative	9,903,193	7,475,919	8,116,164
Interest	399,464	1,685,694	441,206
Retirement of debt	—	1,862,164	—
	39,970,513	44,448,693	36,201,787
Income (loss) before provision for income taxes and minority interest	1,132,209	(4,501,430)	(9,809,957)
Deferred income tax expense (benefit)	93,000	391,000	(59,000)
Net income (loss) before minority interest	1,039,209	(4,892,430)	(9,750,957)
Minority interest	—	(279,314)	(209,341)
Net income (loss)	1,039,209	(5,171,744)	(9,960,298)
Less dividends and accretion on preferred shares	356,867	3,774,395	6,590,886
Net income (loss) applicable to common stockholders	$ 682,342	$ (8,946,139)	$ (16,551,184)
Basic and diluted income (loss) per common share—Basic	$ 0.01	$ (0.23)	$ (0.84)
Basic and diluted income (loss) per common share—Diluted	$ 0.01	$ (0.23)	$ (0.84)
Weighted average common shares outstanding—Basic	52,966,115	39,177,816	19,739,048
Weighted average common shares outstanding—Diluted	54,511,578	39,177,816	19,739,048

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
Years ended December 31, 2006, 2005 and 2004

	Preferred stock		Common stock		Additional paid−in capital	Accumulated deficit	Accumulated other comprehensive income	Treasury stock	Total Stockholders' equity
	Shares	Amount	Shares	Amount					
Balance at January 1, 2004	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 of $6,805,458	—	—	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
Issuance of common stock, net of offering costs of $5,362,421	—	—	7,498,021	750	100,416,701	—	—	—	100,417,451
Shares issued from exercise of options	—	—	942,985	94	4,173,350	—	—	—	4,173,444
Shares issued from exercise of warrants	—	—	214,831	22	2,265,211	—	—	—	2,265,233
Conversion to common stock from debentures	—	—	3,859,251	386	23,267,583	—	—	—	23,267,969
Conversion to common stock from preferred stock	(5,908,473)	(69,738,041)	5,890,895	589	69,737,452	—	—	—	—
Retirement of common stock	—	—	(15,453)	(2)	(219,055)	—	—	—	(219,057)
Dividends declared on preferred stock	—	—	—	—	(3,677,145)	—	—	—	(3,677,145)
Accretion of preferred stock to redemption value	—	97,250	—	—	(97,250)	—	—	—	—
Comprehensive loss									
Net loss	—	—	—	—	—	(5,171,744)	—	—	(5,171,744)
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	(585,483)	—	(585,483)
Total comprehensive loss									(5,757,227)

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY (Continued)
Years ended December 31, 2006, 2005 and 2004

	Preferred stock		Common stock		Additional paid−in capital	Accumulated deficit	Accumulated other comprehensive income	Treasury stock	Total Stockholders' equity
	Shares	Amount	Shares	Amount					
Balance at December 31, 2005	652,336	7,629,622	52,738,384	5,274	353,714,161	(82,861,220)	280,292	(728,055)	278,040,074
Issuance of common stock	—	—	488,540	49	6,944,699	—	—	—	6,944,748
Shares issued from exercise of options	—	—	483,699	48	4,195,933	—	—	—	4,195,981
Shares issued from the exercise of warrants	—	—	160,573	16	1,784,286	—	—	—	1,784,302
Conversion to common stock from debentures	—	—	16,347	1	99,996	—	—	—	99,997
Conversion to common stock from preferred stock	(380,336)	(4,389,024)	279,869	28	4,388,996	—	—	—	—
Retirement of common stock	—	—	(24,358)	(2)	(360,046)	—	—	—	(360,048)
Dividends declared on preferred stock	—	—	—	—	(344,568)	—	—	—	(344,568)
Stock based compensation	—	—	—	—	623,993	—	—	—	623,993
Accretion of offering costs	—	12,299	—	—	(12,299)	—	—	—	—
Net income	—	—	—	—	—	1,039,209	—	—	1,039,209
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	(139,370)	—	(139,370)
Total comprehensive loss									899,839
Balance at December 31, 2006	272,000	$ 3,252,897	54,143,054	$ 5,414	$ 371,035,151	$ (81,822,011)	$ 140,922	$ (728,055)	$ 291,884,318

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENTS OF CASH FLOWS
Year ended December 31,

	2006	2005	2004
Cash flows from operating activities:			
Net income (loss)	$ 1,039,209	$ (5,171,744)	$ (9,960,298)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:			
Accretion of discount on available for sale debt securities	(75,414)	(553,332)	(669,882)
Amortization and write−off of deferred bond offering costs	19,317	1,158,865	396,160
Gain on sale of U.S. Treasury bonds—available for sale	(156,379)	(1,117,239)	(58,693)
Depreciation, depletion, amortization and impairment	11,711,640	3,628,610	4,075,496
Gain on sale of oil and gas properties	—	(203,487)	(120,193)
Expense on the issuance of warrants	—	21,705	—
Common stock surrendered in settlement of receivable	(360,048)	(219,057)	—
Stock compensation expense	623,993	—	—
Deferred tax expense (benefit)	93,000	391,000	(59,000)
Change in assets and liabilities:			
Decrease in trading securities	—	174,247	26,906
(Increase) decrease in accounts receivable—trade	(1,928,508)	(2,403,937)	904,255
Decrease in accounts receivable from affiliated partnerships	83,466	24,941	245,974
(Increase) decrease in other assets	2,254,918	(5,702,936)	2,362,056
Increase (decrease) in accounts payable and accrued expenses	(739,078)	9,779,832	7,122,794
Decrease in deferred income from affiliated partnerships	(1,765,829)	(10,142,560)	(10,529,883)
Increase (decrease) in other long−term liabilities	20,600	(13,069)	1,757,769
Net cash provided by (used in) operating activities	10,820,887	(10,348,161)	(4,506,539)
Cash flows from investing activities:			
Purchase, exploration and development of oil and gas properties	(87,522,271)	(71,591,433)	(27,093,223)
Purchases of property and equipment	(1,387,453)	(344,923)	(9,725)
Proceeds from sale of oil and gas properties, net of selling fees	—	372,864	120,193
Proceeds from sale of property and equipment	—	—	24,000
Purchases of U.S. Treasury bonds—available for sale	—	—	(2,367,786)
Proceds from U.S. Treasury bonds—available for sale	727,826	16,909,189	293,858
Net cash used in investing activities	(88,181,898)	(54,654,303)	(29,032,683)
Cash flows from financing activities:			
Payments on long−term debt	(196,256)	(19,816,280)	(1,620,679)
Issuance of common stock, net	5,947,052	101,104,552	116,632,741
Issuance of preferred stock, net	—	—	126,730
Dividends paid on preferred stock	—	(1,574,594)	(6,207,684)
Net cash provided by financing activities	5,750,796	79,713,678	108,931,108
Net increase (decrease) in cash and cash equivalents	(71,610,215)	14,711,214	75,391,886
Cash and cash equivalents at beginning of year	114,632,099	99,920,885	24,528,999
Cash and cash equivalents at end of year	$ 43,021,884	$ 114,632,099	$ 99,920,885
Supplemental disclosure of cash flow information			
Cash paid for interest, net of amount capitalized	$ 380,147	$ 1,467,949	$ 45,082
Cash paid for income taxes	—	—	—
Noncash investing and financing activities:			
Conversion to common stock from convertible debt	$ 99,997	$ 24,132,500	$ 68,000
Accrued preferred stock dividend	136,284	383,786	1,574,594
Preferred stock issued to minority interest	—	—	500,986
Common stock issued to pay dividends	592,069	3,293,355	—
Change in accounts payables relating to oil and gas property	1,675,757	299,504	—
Common stock issued for oil and gas properties	6,385,908	2,436,228	—
Increase in asset retirement liability	632,994	2,754,541	7,904

The accompanying notes are an integral part of these statements.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES

Nature of Operations

Warren Resources, Inc. (the "Company" or "Warren"), was originally formed on June 12, 1990 for the purpose of acquiring and developing oil and gas properties. The Company is incorporated under the laws of the state of Maryland. The Company's properties are primarily located in Wyoming, California, New Mexico, North Dakota and Texas. 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 accounts of the Company, its wholly−owned subsidiaries, Warren Development Corp., Warren Drilling Corp., Warren Management Corp., Warren Resources of California, Inc, Warren Energy Services LLC and Warren E & P, Inc. The Company has consolidated limited liability companies in which the Company has a majority ownership interest. 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−1999 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.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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 drilling 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. During 2006, the Company completed its remaining obligations under the drilling contracts with affiliated partnerships.

Well services revenue is recognized when services are performed.

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 that exceed federally insured limits. At December 31, 2006, the Company had approximately 49%, 27% and 24% of its cash and cash equivalents with three financial institutions. 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.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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 from joint interest owners and oil and gas purchasers. 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.

Investments

The Company classifies its debt 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 recorded 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. Preferred stock is accreted to its 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

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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

The Company capitalized interest relating to its California and Wyoming properties in accordance with Statement of Financial Accounting Standards ("SFAS") No. 34, *Capitalization of Interest Costs*. Assets qualifying for interest capitalization represent lease costs associated with undeveloped acreage on which exploration activities are in progress. Interest capitalization commences when activities necessary to ready the asset for its intended use have been incurred and continues as long as activities necessary to get the lease ready for its intended use are in progress. If the Company suspends these activities, interest capitalization shall cease until activities are resumed. However, brief interruptions and interruptions that are externally imposed do not result in cessation.

Interest of approximately $1,700,000 and $5,900,000 was capitalized during the years ended December 31, 2005 and 2004, respectively, relating to California and Wyoming properties on which exploration activities were in progress during 2005 and 2004.

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.

Stock Based Compensation

Prior to January 1, 2006, the Company accounted for nonqualified stock options using the intrinsic value method under Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB 25"). Under APB 25, if the exercise price of employee stock options equaled the market price of the underlying stock on the grant date, no compensation expense was recorded. The Company had adopted the disclosure−only provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock−Based Compensation* ("SFAS 123"). No stock−based compensation cost for nonqualified stock options was recognized in the Consolidated Statements of Operations for the year ended December 31, 2005 and 2004, respectively. Effective January 1, 2006, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123(R), *Accounting for Stock−Based Compensation* ("SFAS 123(R)"), using the modified−prospective−transition method. Under that transition method, compensation cost recognized in 2006 includes: (a) compensation cost for all

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

share−based payments granted prior to, but not yet vested as of January 1, 2006 and (b) compensation cost for all share−based payments granted subsequent to January 1, 2006. The compensation cost is based on the grant−date fair value calculated using a Black−Scholes−Merton option−pricing formula and is amortized over the vesting period in accordance with provisions of Statement 123(R). For the year ended December 31, 2006, the Company recognized approximately $600,000 in compensation expense related to non−qualified stock option plans.

The following table is presented to illustrate the proforma effect on loss before provision for income taxes, net loss and loss per common share as if the Company had applied the provisions of SFAS 123R during 2005 and 2004.

	2005	2004
Loss before provision for income taxes		
As reported	$ (4,501,430)	$ (9,809,957)
Deduct: Stock−based employee compensation expense under SFAS 123	(2,645,396)	(963,483)
Pro forma	$ (7,146,826)	$ (10,773,440)
Net loss applicable to common stockholders		
As reported	$ (8,946,139)	$ (16,551,184)
Deduct: Stock−based employee compensation expense under SFAS 123	(2,645,396)	(963,483)
Pro forma	$ (11,591,535)	$ (17,514,667)
Basic and diluted loss per common share:		
As reported	$ (0.23)	$ (0.84)
Pro forma	$ (0.30)	$ (0.89)

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 2006, 2005 and 2004, respectively: No expected dividends, weighted average volatility of 47%, 29% and 28%, risk−free interest rates of 4.67%, 3.69% and 3.60% and expected lives of 3.5 years for incentive options issued in 2006 and expected lives of 5 years for incentive options issued in 2005 and 2004, respectively. The volatility assumptions were developed using a peer group of similar energy companies and our stock price. The weighted average fair value of the options issued in 2006, 2005 and 2004 was $5.46, $3.14 and $2.90, respectively.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (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 39 years. Major classes of property and equipment consisted of the following at December 31:

	2006	2005
Equipment	$ 957,913	$ 957,913
Automobiles and trucks	561,687	274,940
Furniture and fixtures	333,100	253,120
Land and buildings	817,367	99,237
Office equipment	503,967	101,371
	3,174,034	1,686,581
Less accumulated depreciation and amortization	1,422,888	1,126,969
	$ 1,751,146	$ 559,612

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 debentures and preferred stock are converted using the if−converted method. Conversion or exercise is not assumed if the results are antidilutive.

For the year ended December 31, 2006, diluted weighted average common shares outstanding includes in the money employee stock options of 1,015,192 and in the money warrants of 530,271, respectively.

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

	Year ended December 31,		
	2006	2005	2004
Employee stock options	475,500	2,510,721	2,625,206
Convertible debentures	71,314	104,240	5,188,788
Preferred stock	272,000	489,252	6,560,809
Warrants	—	2,968,109	3,109,643

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 0.5 (Note D).

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

At December 31, 2006, the Convertible Debentures may be converted until maturity at 100% of principal amount into common stock of the Company at prices ranging from approximately $35.00 to $50.00 (Note C).

Goodwill

The Company applies SFAS 142, *Goodwill and Other Intangible Assets,* which addresses financial accounting and reporting for acquired goodwill and other intangible assets and requires that goodwill and intangibles with indefinite lives no longer be amortized, but instead be periodically reviewed for impairment. There were no indicators that would indicate that the carrying amount of goodwill was impaired during the periods presented.

Asset Retirement Obligations

The Company accounts for its asset retirement obligations in accordance with SFAS No. 143. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a risk adjusted rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units−of−production method on a field−by−field basis. The associated liability is classified in other long−term liabilities in the accompanying Consolidated Balance Sheets. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense, and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion, amortization and impairment. The Company has treasury bills held in escrow with a fair market value of $2,902,000 that are legally restricted for potential plugging and abandonment liability in the Wilmington field which are recorded in non current assets in the Consolidated Balance Sheets.

A reconciliation of the Company's asset retirement obligations is as follows:

	December 31, 2006	December 31, 2005
Balance at beginning of year	$ 3,701,076	$ 883,832
Liabilities incurred in current year	646,989	2,910,472
Liabilities settled in current year	(193,401)	(168,999)
Accretion expense	356,071	75,771
Carrying amount	$ 4,510,735	$ 3,701,076

Reclassification

Certain reclassification has been made in the prior year financial statements to conform with the current year presentation. Accretion expense on asset retirement liabilities has been reclassified from Interest expense to depreciation, depletion, amortization and impairment.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

Accounting Pronouncements

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin ("SAB") No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements.* SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a balance sheet (iron curtain) approach in assessing materiality and provides for a one−time cumulative effect transition adjustment. SAB No. 108 is effective for our fiscal year 2006 annual financial statements. The adoption of SAB No. 108 did not have a material impact on the Company's consolidated financial position or results of operations.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* ("FIN 48"). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company's financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 will not have a material impact on the Company's consolidated financial position or results of operations.

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in the company's Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, "the Fair Value Option for Financial Assets and Financial Liabilities−−−Including an amendment of FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value. Unrealized gains and losses on items for which the fair value option has been elected will be recognized in earnings at each subsequent reporting date. SFAS 159 is effective for us January 1, 2008. The adoption of SFAS No. 159 is not expected to have a material impact on the Company's consolidated financial position or results of operations.

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, 2006	December 31, 2005
U.S. Treasury Bonds, stripped of interest, maturing 2020 and 2022, aggregate par value of $2,496,000 and $4,070,000, respectively		
Amortized cost	$ 988,837	$ 1,484,869
Gross unrealized gains	229,713	462,083
Estimated fair value	$ 1,218,550	$ 1,946,952

During 2006, 2005 and 2004, the Company recognized approximately $(64,000), $(156,000) and $(106,000), respectively, of unrealized gains (losses) on its trading securities and $156,000, $1,117,000 and $59,000, 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 and debentures (Notes C & F).

The amortized cost and estimated fair values of available−for−sale securities, by contractual maturity at December 31, 2006 are shown below.

	Amortized cost	Estimated fair value
Due within one year	$ —	$ —
Due after one year through five years	—	—
Due after five years through ten years	—	—
Due after ten years	988,837	1,218,550
Total	$ 988,837	$ 1,218,550

NOTE C—LONG−TERM LIABILITIES

Debentures consist of the following at December 31:	2006	2005
Secured Convertible Debentures, due December 31, 2020, bearing interest at 12%, due in monthly payments. As of December 31, 2006 and 2005, principal collateralized by $1,390,000 and $1,470,000, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2020.(1)	$ 1,390,000	$ 1,470,000
Secured Convertible Debentures, due December 31, 2022, bearing interest at 12%, due in monthly payments. As of December 31, 2006 and 2005, principal collateralized by $1,106,000 and $1,136,000 respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2022.(1)	1,106,000	1,136,000
	2,496,000	2,606,000
Less current maturities	249,600	260,600
Long−term portion	$ 2,246,400	$ 2,345,400

(1) 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.

The Convertible 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 Debentures and range from approximately $35.00 to $50.00. Conversion of the Debentures would increase the number of shares outstanding at December 31 as follows:

2006	Maturity date	Outstanding principal amount	Per share conversion price	Common shares if converted
Secured Convertible 12% Debentures	December 31, 2020	$ 1,390,000	$ 35.00	39,714
Secured Convertible 12% Debentures	December 31, 2022	1,106,000	35.00	31,600
		$ 2,496,000		71,314

NOTE C—LONG−TERM LIABILITIES (Continued)

During 2005, the Company retired certain debentures under the original terms of the agreement which resulted in retirement of this debt expense of $1.9 million. Due to this retirement, the Company no longer has annual sinking fund requirements to purchase zero coupon U.S. Treasury Bonds as collateral for its outstanding debentures. Each year, holders of the Secured Convertible Debentures may tender to the Company up to 10% of the aggregate amount outstanding. As of December 31, 2006, the estimated principal that can be tendered by the secured holders is as follows:

Fiscal year ending December 31		
2007	$	249,600
2008		224,640
2009		202,176
2010		181,958
2011		163,763
Thereafter		1,473,863
	$	2,496,000

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

	2006		2005	
Debt collateralized by treasury stock	$	690,005	$	776,260
Asset retirement obligations		4,510,735		3,701,071
Litigation provision		1,823,156		1,823,156
		7,023,896		6,300,487
Less current maturities		*257,028*		*325,994*
Long−term portion	$	6,766,868	$	5,974,493

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, 2006 and 2005 was approximately $690,000 and $776,000, respectively, net of discount of approximately $217,000 and $290,000, 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.

On November 16, 2006, the Company entered into a five year, $150 million credit agreement (the “Credit Agreement”) with JPMorgan Chase Bank, N.A. (the “Agent”). The Credit Agreement provides for a revolving credit facility up to the lesser of (i) the borrowing base, (ii) $150 million and (iii) the draw limit requested by the Company. The Credit Agreement matures on November 15, 2011. It is secured by substantially all of our assets and is guaranteed by two of the Company’s wholly−owned subsidiaries, Warren Resources of California, Inc. and Warren E&P, Inc.

The borrowing base will be determined by the Agent at least semi−annually on April 1 and October 1 of each year, beginning April 1, 2007. The initial borrowing base is $40 million and based in part on the

NOTE C—LONG−TERM LIABILITIES (Continued)

proven reserves of the Company. Depending on the current level of borrowing base usage, the annual interest rate on each borrowing will be the Company's option of either: (a) the higher of (i) the Agent's prime rate of interest announced from time to time, and (ii) the Federal Funds rate most recently determined by the Agent plus ½% per annum, plus an applicable margin that ranges from 0.25% to 1.0% or (b) the Eurodollar loan rate plus an applicable margin that ranges from 1.25% to 2.0%. The Company has no outstanding borrowings under this facility. Interest is paid quarterly in arrears.

The Company is subject to certain covenants under the terms of the Credit Agreement which include, but are not limited to, maintenance of the following financial ratios: (1) minimum current ratio of 1.0 to 1.0, and (2) a maximum total net debt to EBITDAX (as defined in the Credit Agreement) of 3.50 to 1.0. The Credit Agreement also places certain restrictions on indebtedness, dividends, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of the Company's common stock, speculative commodity transactions, transactions with affiliates and other matters. The Company is in compliance with these covenants at December 31, 2006.

The credit facility will be used for working capital, capital expenditures, permitted acquisitions and general corporate purposes. The Credit Agreement is subject to customary events of default, the occurrence and continuation of which could result in the acceleration by the Agent of amounts due under the facility.

NOTE D—STOCKHOLDERS' EQUITY

During 2006, the Company issued 387,492 shares to partners in a drilling partnership in exchange for the oil and gas assets in that partnership. These shares had a value of approximately $5.6 million based on the closing price of our publicly stock on the day of issuance. Also during 2006, the Company issued 54,225 shares to individuals in exchange for their interest in drilling partnerships. These shares were valued at approximately $818,000 based on the price of our stock on the date of issuance.

On December 27, 2005, the Company sold 6,900,000 shares of common stock to the public in a secondary offering at a price of $14.50 per share which included the underwriter's over−allotment option. After deducting the underwriters' commission and offering expenses, the Company received total net proceeds of approximately $94,700,000.

During 2005, the Company called for full redemption the following convertible debentures: 2009 Secured Debentures; 2010 Secured Bonds; 2010 Sinking Fund Debentures; 2015 Sinking Fund Debentures and 2016 Secured Convertible Debentures. Debenture holders were given the option to redeem for cash or receive common stock of the Company. Accordingly, the Company issued 3,859,251 shares of its common stock to certain debenture holders.

During 2006, the Company issued 46,823 shares of common stock with a value of approximately $592,000, in lieu of Preferred Stock dividend payments for the fourth quarter of 2005 and the first, second and third quarters of 2006. During 2005, the Company issued 323,847 shares of common stock with a value of approximately $3,300,000, in lieu of the second and third quarter Preferred Stock dividend payment.

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

NOTE D—STOCKHOLDERS' EQUITY (Continued)

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 2006, 2005 and 2004, the Company issued 483,699, 942,985 and 186,056 shares of common stock to individuals who exercised options at exercise prices ranging from $4 to $10.00 per share. Also during 2006, 2005 and 2004, the Company issued 160,573, 214,831 and 8,482 shares of common stock to investors who exercised Class A warrants at $10 per share and Class B warrants at $12.50 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, the Company issued 11,331 shares, of redeemable convertible preferred stock through a private placement with accredited investors at a price of $12 per share for gross proceeds of $135,972. Also, during 2004, the Company issued 41,749 shares, 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. The preferred stock has an 8% cumulative dividend, payable quarterly. Preferred dividends of approximately $136,000 and $384,000 were accrued at December 31, 2006 and 2005, respectively. 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 into common stock at the election of the holder based on the table below. The conversion rate is subject to adjustment as defined by the agreement.

Period	Preferred to common
Prior to June 30, 2005	1 to 1
July 1, 2005 through June 30, 2006	1 to .75
July 1, 2006 through redemption	1 to .50

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

NOTE D—STOCKHOLDERS' EQUITY (Continued)

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 2006, the Company issued 268,508 shares of common stock to preferred stock investors who exchanged on a 1 to 0.75 basis and 11,361 shares of common stock to preferred stock investors who exchanged on a 1 to 0.50. During 2005, the Company issued 5,838,161 shares of common stock to preferred stock investors who exchanged on a 1 to 1 basis and 52,734 shares of common stock to preferred stock investors who exchanged on a 1 to 0.75 basis. At December 31, 2006, there were 218,920 preferred shares outstanding that the Company may be required to redeem at the aggregate Redemption Price of $2,627,040 during the year ended December 31, 2010, and 53,080 preferred shares outstanding that the Company may be required to redeem at the aggregate Redemption Price of $636,960 during the year ended December 31, 2011 and thereafter. As noted above, the Company could, at its option, settle the redemption requests in shares of common stock.

Securities Authorized for Issuance Under Compensation Plans

The table below includes information about our equity compensation plans as of December 31, 2006:

	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	765,250	$ 10.83	584,250
2001 Stock Incentive Plan	2,500,000	424,783	7.92	1,312,977
2001 Key Employee Stock Incentive Plan	2,500,000	1,266,750	6.46	1,008,250
Total	6,975,000	2,456,783	8.07	2,905,477

During 2006, the Board of Directors approved and the Company issued 497,250 stock options to officers and employees of the Company exercisable at prices ranging from $12.53 to $13.85 per share.

During 2005, the Board of Directors approved and the Company issued 768,500 stock options to officers and employees of the Company exercisable at prices ranging from $9.05 to $14.85 per share.

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. During 2004, 60,000 stock options were forfeited as a result of employee terminations. 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 vest over time.

NOTE D—STOCKHOLDERS' EQUITY (Continued)

As a result of job performance, during 2005 the Compensation Committee elected to accelerate the vesting of certain unvested stock options previously awarded to employees, officers and directors of the Company under various stock option plans. As a result of this action, options to purchase approximately 1.0 million shares of our common stock that would otherwise have vested over the next two years became fully vested. A summary of the status of the Company's options issued to employees as of December 31, 2006, 2005 and 2004 and changes during the years ended on those dates is presented below:

	Incentive options	Weighted Average Exercise Price
Options outstanding—January 1, 2004	2,301,012	$ 5.10
Issued	630,250	$ 7.00
Exercised	(186,056)	$ 4.00
Expired	—	
Forfeited	(60,000)	$ 4.00
Options outstanding—December 31, 2004	2,685,206	$ 5.66
Issued	768,500	$ 9.38
Exercised	(942,985)	$ 4.40
Expired	—	
Forfeited	—	0
Options outstanding—December 31, 2005	2,510,721	$ 7.23
Issued	497,250	$ 13.71
Exercised	(483,699)	$ 8.67
Expired	—	
Forfeited	(67,489)	$ 13.82
Options outstanding—December 31, 2006	2,456,783	$ 8.07

The following table summarizes information about the Company's stock options outstanding at December 31, 2006:

Exercise Price	Options Outstanding at Year End	Weighted Average Remaining Life (In Years)	Options Exercisable at Year End
$4.00	672,783	1.40	672,783
$7.00	609,500	2.27	609,500
$9.05	689,000	3.11	689,000
$11.00	10,000	3.72	10,000
$12.53	50,000	4.87	0
$13.70	30,000	4.64	0
$13.85	375,500	4.22	0
$14.85	20,000	3.87	15,000
Total	**2,456,783**	**2.67**	**1,996,283**

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2006	2,456,783	$ 8.07	2.67	$ 9,918
Exercisable at December 31, 2006	1,996,283	6.78	2.29	$ 9,918

The total intrinsic value of options exercised during the year ended December 31, 2006, 2005 and 2004 was $2.0 million, $2.0 million, and $0.6 million, respectively.

As of December 31, 2006 there was $1.9 million of total unrecognized compensation cost related to non−vested stock options granted under the Plans. This cost is expected to be recognized over a weighted average period of 3 years.

Cash received from option exercises under all stock−based payment arrangements for the twelve months ended December 31, 2006 was $4.2 million. We issue new shares of common stock to settle option exercises.

A summary of the status of the Company's warrants issued as of December 31, 2006, 2005 and 2004 and changes during the years ended on those dates is presented below:

	Warrants	Weighted Average Exercise Price
Warrants outstanding—January 1, 2004	180,625	$ 10.00
Issued	2,937,500	$ 11.25
Exercised	(8,482)	$ 10.00
Expired	—	
Forfeited	—	0
Warrants outstanding—December 31, 2004	3,109,643	$ 11.18
Issued	73,297	$ 9.45
Exercised	(214,831)	$ 10.79
Expired	—	
Forfeited	—	
Warrants outstanding—December 31, 2005	2,968,109	$ 11.17
Issued	—	
Exercised	(160,573)	$ 11.11
Expired	—	
Forfeited	—	
Warrants outstanding—December 31, 2006	2,807,536	$ 11.17

As of December 31, 2006 the aggregate intrinsic value of warrants outstanding was $1.5 million. The weighted average remaining life was 2.37.

NOTE E—INCOME TAXES

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

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

	2006	2005	2004
Income taxes at federal statutory rate (34%)	$ 384,951	$ (1,530,486)	$ (3,335,385)
Change in valuation allowance	1,816,061	2,649,040	4,375,484
Nondeductible expenses	44,926	49,682	45,064
Deductions for the exercise of stock options	(432,077)	—	—
State income taxes at statutory rate	67,933	(270,086)	(588,597)
Adjustment of estimated income tax provision of prior year	(1,536,756)	(390,594)	(482,418)
Other	(252,038)	(116,556)	(73,148)
	$ 93,000	$ 391,000	$ (59,000)

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

	2006	2005
Deferred tax assets relating to:		
Net operating loss carryforward	$39,753,087	$33,741,548
Stock option expense	249,597	—
Other	314,400	314,400
	40,317,084	34,055,948
Less valuation allowance	33,161,108	31,345,047
Total deferred tax assets	7,155,976	2,710,901
Deferred tax liabilities relating to:		
Oil and gas properties and tangible equipment	7,050,605	2,304,939
Net unrealized gain on investments	105,371	405,962
Total deferred tax liabilities	7,155,976	2,710,901
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 $1,816,061, $2,649,040 and $4,375,484 for the years ended December 31, 2006, 2005 and 2004, respectively.

At December 31, 2006, the Company had net operating loss carryforwards for federal income tax purposes of approximately $99,400,000, which begin to expire in 2012.

NOTE F—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, 2006, the maximum termination compensation for all executives is approximately $2,400,000.

The Company has a contract with Nabors Well Services Co. for drilling wells in California that expires September 1, 2007. The contract provides for an operating rate of $22,490 per day. In the event of early termination, a shortfall charge of $8,922 per day is incurred for each day prior to the initial termination date, which is limited to a maximum of $1,500,000.

The Company has a contract with Ensign United States Drilling California, Inc. for drilling wells in California that expires August 18, 2007. The contract provides for an operating rate of $12,640 per day. In the event of early termination, the Company will incur demobilization costs in the amount of $23,000 plus the actual costs incurred by the contractor for removing and returning the rig to the contractor's yard, for a maximum of approximately $1,454,000 in 2007.

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 transportation contract with Williston Basin Interstate ("WBI") through March 31, 2007 related to its LX Bar lease. If the Company fails to deliver 2,000 Mcf of gas per day, WBI may charge the Company an additional transportation fee (the "Additional Transportation Fee"). The Additional Transportation Fee is defined as the amount of deficient Mcf times the transportation rate of approximately $0.30 per Mcf. During 2006, 2005 and 2004, the Company paid Additional Transportation Fees of approximately $2,000, $271,000 and $185,000, respectively. The maximum deficiency charge through the period of contract expiration is approximately $54,000.

Repurchase Agreements

For certain repurchase agreements relating to partnerships formed from 1999 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 partnership 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, 2006, the aggregate formula purchase

NOTE F—COMMITMENTS AND CONTINGENCIES (Continued)

price with respect to these partnerships was approximately $73,880,000. However, this amount is limited to approximately $13,016,000 based on the aggregate PV−10 of the assets in these partnerships. This limitation may increase when the Company places the remaining 26 net wells on production on behalf of these five 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 investor's 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, 2006 and 2005, the face amounts of U.S. Treasury Bonds securing the Company's obligation under the Trust Indenture Agreements were $2,496,000 and $2,606,000, respectively, and the market values of these U.S. Treasury Bonds were approximately $1,219,000 and $1,258,000, respectively (see Note C).

Leases

The Company leases corporate 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 2005, the Company entered into an office lease in Roswell, New Mexico, which expires in May 2007. In March 2005, the Company entered into an office lease in Long Beach, California which expires in June 2010.

Future minimum annual rental payments, which are subject to escalation and include utility charges as of December 31, 2006, are as follows:

Year ending December 31		
2007	$	212,909
2008		91,866
2009		55,150
2010		27,796
	$	387,721

Rent expense under these leases was approximately $313,000, $304,000 and $252,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

Litigation

In 2005, Warren recorded a provision for $1,800,000 relating to contingent liability that it may face as a result of a lawsuit originally filed in 1998 by Gotham Insurance Company in the 81st Judicial District Court of Frio County, Texas seeking a refund of approximately $1.8 million paid by Gotham and other insurers for a well blow−out policy that occurred in 1997. After several appeals to the Texas Court of

NOTE F—COMMITMENTS AND CONTINGENCIES (Continued)

Appeals and the Texas Supreme Court, the case has been remanded to the trial court for further proceedings in 2007.

The Company is a party to various other matters of litigation arising in the normal course of business. 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 G—EMPLOYEE BENEFIT PLANS

The Company has a retirement plan covering substantially all qualified employees under section 401(k) of the Internal Revenue Code. On October 1, 2006, the Company changed its matching policy to contribute 100% of the participant's contribution. Prior to October 1, 2006, 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's contributions vest over five years at 20% per year. The Company may also make discretionary contributions. The Company's expenses under the plan were approximately $127,000, $85,000 and $64,000 for the years ended December 31, 2006, 2005 and 2004, respectively.

NOTE H—RELATED PARTY TRANSACTIONS

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.

NOTE I—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.

NOTE I—FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

U.S Treasury Bonds—Trading and Available−For−Sale Securities. 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.

	2006		2005	
	Fair value	Carrying amount	Fair value	Carrying amount
Financial assets				
Cash and cash equivalents	$ 43,021,884	$ 43,021,884	$ 114,632,099	$ 114,632,099
U.S. Treasury bonds—available−for−sale	1,218,550	1,218,550	1,946,952	1,946,952
Financial liabilities				
Fixed rate debentures	$ 2,870,140	$ 2,496,000	$ 3,114,363	$ 2,606,000
Other long−term liabilities	4,943,712	4,943,712	4,477,332	4,477,332

NOTE J—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:

	2006	2005	2004
Property acquisition—unproved	$ 2,203,857	$ 2,509,272	$ 3,046,654
Property acquisition—proved	3,555,851	41,347,474	4,495,283
Exploration costs	4,810,660	9,927,037	902,564
Development costs	76,951,903	17,807,650	18,648,722
	$ 87,522,271	$ 71,591,433	$ 27,093,223

Effective January 1, 2005, the Company acquired all of the right, title and interest in the Wilmington Townlot Unit for $14.8 million. Additionally, effective February 1, 2005, Warren’s wholly owned operating subsidiary, Warren E&P, Inc., was elected operator of the Wilmington Unit. Additionally on December 9, 2005, the Company acquired all of the right, title and interest in the North Wilmington Unit for $23 million and Warren E&P was elected the new operator of the property.

Also, during the three months ended March 31, 2006, the Company acquired all minority interests in the 1994 thru 1997 drilling partnerships for approximately $1.4 million in cash. The minority interest relating to these partnerships was recorded as a reduction in the cost basis of the assets acquired.

Asset retirement cost included in proved property acquisition costs increased by approximately $647,000, $2,910,000 and $8,000 for 2006, 2005 and 2004, respectively.

NOTE J—OIL AND GAS INFORMATION (Continued)

During the years ended December 31, 2006, 2005 and 2004, exploration costs of approximately $675,000, $176,000 and $143,000, respectively, were expensed.

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

	2006	2005
Unproved oil and gas properties	$ 73,197,840	$ 60,254,586
Proved oil and gas properties	259,239,752	192,034,405
	332,437,592	252,288,991
Less accumulated depreciation, depletion amortization and impairment	71,937,267	66,384,797
	$ 260,500,325	$ 185,904,194

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

	2006	2005	2004
Revenues	$ 31,264,379	$ 14,164,196	$ 6,576,523
Production costs	(13,034,963)	(7,119,363)	(3,792,002)
Exploration costs	(675,003)	(176,157)	(143,135)
Accretion of asset retirement obligation	(356,071)	(75,771)	(52,711)
Depreciation, depletion, amortization and impairment	(10,850,419)	(3,321,504)	(3,840,841)
Gain (Loss) from oil and gas producing activities	$ 6,347,923	$ 3,471,401	$ (1,252,166)

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 $10,850,419, $3,321,504 and $3,840,781 or $2.87, $1.70 and $3.13 per equivalent Mcf of production for the years ended December 31, 2006, 2005 and 2004, respectively. These amounts include impairment expenses, primarily for unproved properties of $4,590,604, $208,407 and $2,279,828 for the years ended December 31, 2006, 2005 and 2004, respectively. In the fourth quarter of 2006, we determined that the Pacific Isle project would not produce commercial quantities of gas and recorded an impairment expense of approximately $4,256,000 which includes exploratory well cost, leasehold cost, unsalvageable tangibles and gathering costs.

NOTE J—OIL AND GAS INFORMATION (Continued)

The following table sets forth the Company's capitalized exploratory well activity during each of the years ended December 31:

	2006	2005	2004
Beginning capitalized exploratory well costs	$ 7,602,958	$ 9,159,398	$ 5,158,942
Additions to exploratory well costs pending the determination of proved reserves	6,636,247	2,002,718	4,000,456
Reclassifications due to determination of proved reserves	—	(3,559,158)	—
Exploratory well costs charged to expense	(1,016,632)	—	—
Ending capitalized exploratory well costs	$ 13,222,573	$ 7,602,958	$ 9,159,398

The following table provides an aging as of December 31, 2006, 2005 and 2004 of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the date the drilling was completed:

	2006	2005	2004
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 6,636,247	$ 1,590,686	$ 6,983,859
Capitalized exploratory well costs that have been capitalized for a period of more than one year	6,586,326	6,012,272	2,175,539
Ending capitalized exploratory well costs	$ 13,222,573	$ 7,602,958	$ 9,159,398
Number of wells with exploratory well costs that have been capitalized for a period greater than one year	57	42	16

The above exploratory well costs relate to coalbed methane wells that are drilled in our Atlantic Rim and Pacific Rim acreage.

Atlantic Rim—Currently, these wells are in the dewatering phase. Additionally, the Company is currently waiting on the approval of an Environmental Impact Statement covering the Atlantic Rim. Once completed, the Company can proceed with drilling additional wells adjacent to the exploratory wells and install the necessary infrastructure, including the building of a pipeline to these exploratory wells in order to bring these wells on production. The Company has already proven reserves on three pilots in the Atlantic Rim and believes that coal seam is continuous throughout the acreage.

Pacific Rim—Currently, these wells are in the dewatering phase. Due to the lack of existing commercial production in the surrounding area the Company has decided to obtain additional test results and monitor performance of these wells before a determination can be made if the wells will be commercially productive. The Company has already obtained proven reserves in one pilot in the Pacific Rim. The majority of drilling in this project took place from 2004 to 2006.

NOTE K—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.

NOTE K—OIL AND GAS RESERVE DATA (UNAUDITED) (Continued)

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, in accordance with SFAS No. 69 *Disclosures about Oil and Gas Producing Activities*.

Summary of Changes in Proved Reserves

	Year ended December 31,					
	2006		2005		2004	
	Mbbls	Mmcf	Mbbls	Mmcf	Mbbls	Mmcf
Proved reserves						
Beginning of year	50,415	24,353	14,177	18,542	15,124	15,448
Purchase of reserves in place	164	814	19,783	—	—	—
Discoveries and extensions	4,421	7,202	13,888	8,355	39	3,632
Revisions of previous estimates	(467)	(6,492)	2,715	(1,470)	(918)	279
Production	(456)	(1,052)	(148)	(1,074)	(68)	(817)
End of year	54,077	24,825	50,415(1)	24,353(1)	14,177(2)	18,542(2)
Proved developed reserves						
Beginning of year	2,939	10,829	395	8,496	476	7,006
End of year	9,583	9,264	2,939	10,829	395	8,496

(1) Included in 2005 reserves, 922 Mbbls and 136 Mmcf is attributable to consolidated subsidiaries in which there is an average 9% minority interest.

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

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

	December 31,		
	2006	2005	2004
	(Amounts in thousands)		
Future cash inflows	$ 2,844,403	$ 2,714,566	$ 631,190
Future production costs and taxes	(915,146)	(749,922)	(106,363)
Future development costs	(281,878)	(262,305)	(59,541)
Future income tax expenses	(536,541)	(470,106)	(110,161)
Net future cash flows	1,110,838	1,232,233	355,125
Discounted at 10% for estimated timing of cash flows	(698,262)	(769,453)	(162,480)
Standardized measure of discounted future net cash flows	$ 412,576	$ 462,780(1)	$ 192,645(2)

(1) Included in 2005 reserves, $9,673 is attributable to consolidated subsidiaries in which there is an average 9% minority interest.

NOTE K—OIL AND GAS RESERVE DATA (UNAUDITED) (Continued)

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

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

	Year ended December 31,		
	2006	2005	2004
	(Amounts in thousands)		
Sales, net of production costs and taxes	$ (17,554)	$ (6,664)	$ (2,519)
Discoveries and extensions	61,626	167,293	5,967
Purchases of reserves in place	4,493	236,700	—
Changes in prices and production costs	(56,899)	38,354	55,595
Revisions of quantity estimates	(13,051)	31,591	(14,249)
Net changes in development costs	(17,712)	(120,535)	(34)
Interest factor—accretion of discount	63,791	24,229	18,299
Net change in income taxes	(36,156)	(125,491)	(12,788)
Changes in production rates (timing) and other	(38,742)	24,658	(3,752)
Net (decrease) increase	(50,204)	270,135	46,519
Balance at beginning of year	462,780	192,645	146,126
Balance at end of year	$ 412,576	$ 462,780	$ 192,645

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, 2006, 2005 and 2004 were $50.60, $49.05 and $37.59 per Bbl and $4.35, $9.92 and $5.30 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, 2007, 2008 and 2009 are $67,496,094, $58,660,707 and $47,034,812, 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 L—QUARTERLY INFORMATION (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 2006 and 2005 are as follows:

	2006				
	Quarter				
	First	Second	Third	Fourth	Year
Revenues	$ 9,832,450	$ 9,692,984	$ 10,231,222	$ 11,346,066	$ 41,102,722
Gross profit	3,526,546	4,546,679	5,110,197	5,105,590	18,289,012
Net income (loss) applicable to common stockholders	685,031	1,385,205	2,142,536	(3,530,430)	682,342
Income (loss) per share					
Basic and diluted	$ 0.01	$ 0.03	$ 0.04	$ (0.07)	$ 0.01

	2005				
	Quarter				
	First	Second	Third	Fourth	Year
Revenues	8,116,798	7,965,710	10,017,730	13,847,025	39,947,263
Gross profit	2,318,993	652,843	1,275,865	1,616,740	5,684,441
Net loss applicable to common stockholders	(3,368,538)	(2,984,684)	(1,502,562)	(1,090,355)	(8,946,139)
Loss per share					
Basic and diluted	$ (0.10)	$ (0.08)	$ (0.04)	$ (0.02)	$ (0.23)

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 2006, the Company had the following significant adjustment:

- Recognized impairment on oil and gas properties of approximately $4,300,000, relating to exploratory costs for the Pacific Isle project, which was deemed to be non commercial.

The effect of this adjustment decreased basic and diluted income per share by $ (0.08) for the quarter and year ended December 31, 2006, respectively.

NOTE M—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:

	2006	2005	2004
Revenues from external customers			
Turnkey contracts	$ 1,621,462	$ 9,756,209	$ 10,529,883
Oil and gas marketing	2,329,945	10,210,681	6,171,338
Oil and gas operations	31,264,379	14,162,584	6,574,527
Well services	1,029,442	1,554,760	1,070,004
Other	4,857,494	4,263,029	2,046,078
Total	$ 41,102,722	$ 39,947,263	$ 26,391,830
Interest and other income			
Turnkey contracts	$ —	$ —	$ 258
Oil and gas marketing	—	—	—
Oil and gas operations	—	1,612	1,996
Well services	—	—	—
Other	4,765,303	3,300,422	2,086,740
Total	$ 4,765,303	$ 3,302,034	$ 2,088,994
Consolidated revenues			
Total segment revenue	$ 36,245,228	$ 35,684,234	$ 24,345,752
Other	4,857,494	4,263,029	2,046,078
Total	$ 41,102,722	$ 39,947,263	$ 26,391,830
Interest expense			
Turnkey contracts	$ —	$ 2,206	$ 735
Oil and gas marketing	—	—	—
Oil and gas operations	—	—	—
Well services	—	—	—
Other	399,464	1,683,488	440,471
Total	$ 399,464	$ 1,685,694	$ 441,206

NOTE M—SEGMENT INFORMATION (Continued)

	2006	2005	2004
Depreciation, depletion, amortization and impairment			
Turnkey contracts	$ 76,711	$ 103,216	$ 103,216
Oil and gas marketing	—	—	—
Oil and gas operations	11,206,490	3,397,275	3,893,552
Well services	209,231	50,580	—
Other	219,208	77,539	78,728
Total	$ 11,711,640	$ 3,628,610	$ 4,075,496
Operating income (loss)			
Turnkey contracts	$ 543,354	$ (1,624,561)	$ (2,505,934)
Oil and gas marketing	75,125	131,833	142,611
Oil and gas operations	6,347,923	3,471,401	(1,252,166)
Well services	(169,822)	357,590	397,071
Other	(5,664,371)	(6,837,693)	(6,591,539)
Total	$ 1,132,209	$ (4,501,430)	$ (9,809,957)
Assets			
Turnkey contracts	$ —	$ 2,455,065	$ 13,022,081
Oil and gas marketing	276,750	192,642	192,642
Oil and gas operations	319,357,599	314,659,695	121,069,107
Well services	3,191,893	2,897,389	—
Other	1,033,015	559,612	112,626,831
Total	$ 323,859,257	$ 320,764,403	$ 246,910,661
Capital expenditures			
Turnkey contracts	$ —	$ —	$ —
Oil and gas marketing	—	—	—
Oil and gas operations	87,043,709	68,930,660	27,102,948
Well services	478,562	2,660,773	
Other	1,387,453	344,923	—
Total	$ 88,909,724	$ 71,936,356	$ 27,102,948

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(13)	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(13)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(8)	Form of Class A Common Stock Warrant
4.3(8)	Form of Class B Common Stock Warrant
4.4(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.
4.5(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
4.6(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
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(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Norman F. Swanton
10.9(9)	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin
10.10(15)	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Timothy A. Larkin
10.11(15)	Employment Agreement dated as of July 1, 2005, between the Registrant and Lloyd Davies
10.12(15)	Employment Agreement executed on June 17, 2005, between the Registrant and David E. Fleming
10.13(10)	Employment Agreement dated January 1, 2004, between the Registrant and Ellis G. Vickers
10.14(1)	Form of Indemnification Agreement
10.15(1)	Form of Partnership Production Marketing Agreement
10.16(4)	Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc.

10.17(4)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.18(4)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.
10.19(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.
10.20(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.
10.21(14)	Asset Purchase Agreement dated December 9, 2005 by and among Warren Resources, Inc., Warren Resources of California, Inc., Warren E&P, Inc. and Global Oil Production, LLC and Wilmington Management, LLC
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 Grant Thornton LLP
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†	Certification of CEO and CFO pursuant to Section 1350

(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.

(13) Incorporated by reference to the Company's Annual Report on Form 10−K for the year ended December 31, 2004, filed on March 17, 2005.

(14) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed December 12, 2005.

(15) Incorporated by reference to the Company's Current Report on Form 8−K, Commission File No. 000−33275, filed June 17, 2005.

† Filed herewith.

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, 2006 for Disclosure to the Securities and Exchange Commission Williamson Project 6.9180,” 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 6, 2007

/s/ Williamson Petroleum Consultants, Inc.
WILLIAMSON PETROLEUM CONSULTANTS, INC.

Midland, Texas
March 6, 2007

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 5, 2007, accompanying the consolidated financial statements and management's assessment of the effectiveness of internal control over financial reporting included in the Annual Report of Warren Resources, Inc. on Form 10−K for the year ended December 31, 2006. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Warren Resources, Inc. on Form S−3 (File No. 333−130109, effective December 2, 2005) and on Form S−8 (File No. 333−125277, effective May 26, 2005).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 5, 2007

Exhibit 31.1

**CERTIFICATION OF CEO 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 officer 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) 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
   (d) 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 (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (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.

Date: March 6, 2007

/s/ Norman F. Swanton
Norman F. Swanton,
Chairman and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF CFO 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 officer 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) 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) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) 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
   d) 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 (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   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.

Date: March 6, 2007

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

Exhibit 32

CERTIFICATION OF CEO AND CFO 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, 2006 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.

March 6, 2007

/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