WARREN RESOURCES INC (WRES)

10-K/A
Annual report pursuant to section 13 and 15(d)
Filed on 04/05/2012
Filed Period 12/31/2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A
(Amendment No. 1)

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

For the Fiscal Year Ended December 31, 2011

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 (State or other jurisdiction of incorporation or organization)	**11-3024080** (I.R.S. Employer Identification No.)
1114 Ave of the Americas, New York, NY (Address of principal executive offices)	**10036** (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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☒ 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, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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, 2011 was $273,449,301.

The number of shares of registrant's common stock outstanding as of March 5, 2012 was 71,518,810 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 29, 2012, in connection with the registrant's 2012 Annual Meeting of Stockholders, are incorporated herein by reference into Part III of this Annual Report on Form 10-K.

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Explanatory Note

We are filing this Amendment No. 1 on Form 10-K/A (this "Amendment") to our Annual Report on Form 10-K for the year ended December 31, 2011, filed with the Securities and Exchange Commission (the "SEC") on March 6, 2012 (the "Original Filing"), solely to correct inadvertent printer errors concerning the chart included under the caption "Stockholder Return Performance Presentation" located in Part II, Item 5. For convenience, we have repeated the Original Filing in its entirety with the above-mentioned changes in Part II, Item 5, and without Exhibits, except for Exhibits 31.1, 31.2 and 32. Correspondingly, the list of Exhibits in Part IV, Item 15(a)(3) has been modified to show the incorporation by reference of Exhibits 11, 23.1, 23.2, 23.3 and 92.2 that were included with the Original Filing and are not included with this Amendment. Other than as described in the foregoing, none of the financial statements or other disclosures in the Original Filing have been amended or updated. Accordingly, this Form 10-K/A should be read in conjunction with the Company's filings with the Securities and Exchange Commission subsequent to the Original Filing.

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 ability to successfully and economically explore, develop and produce oil and gas resources;
- our ability to obtain permits and governmental approvals;
- the impact of environmental and other governmental regulation;
- our exploration and development drilling prospects, inventories, projects and programs;
- our oil and natural gas reserve estimates;
- volatility in commodity prices and market conditions for oil and natural gas;
- our liquidity and ability to finance our operations and exploration and development activities;
- our future production, revenue, operating costs and results of operations;
- the cost and availability of experienced labor;
- our business and growth strategies;
- our identified drilling locations;
- availability and costs of drilling rigs and field services; and
- our ability to make and integrate acquisitions.

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:

- further adverse changes in general economic conditions, including performance of financial markets, interest rates and unemployment rates;
- unsuccessful drilling activities;
- an inability to develop our reserves through exploration and development activities;

- impact of environmental and other governmental regulation, including delays in obtaining permits and governmental approvals;
- possible legislative or regulatory changes, including severance or production tax regimes, hydraulic-fracturing regulation, additional drilling and permitting regulations, oil and gas derivatives reform, changes in state, federal and foreign income taxes, environmental regulation, environmental risks and liability under federal, state, foreign and local environmental laws and regulations;
- the failure to obtain sufficient capital resources to fund our operations;
- the Company's ability to repay its debt;
- a decline in oil or natural gas production or oil or natural gas prices;
- incorrect estimates of reserve quantities, required operating costs and capital expenditures;
- increases in the cost of drilling, completion and gas gathering or other costs of production and operations;
- hazardous and risky drilling operations; and
- an inability to grow.

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 an independent energy company engaged in the exploration, development and production of domestic onshore crude oil and gas reserves. We focus our efforts primarily on the exploration and development of our waterflood oil recovery properties in the Wilmington field within the Los Angeles Basin of California, and our coalbed methane, or CBM, natural gas properties located in the Rocky Mountain region.

As of December 31, 2011, we owned natural gas and oil leasehold interests in approximately 129,588 gross (69,641 net) acres, approximately 80% of which are undeveloped. Substantially all our undeveloped acreage is located in the Rocky Mountains. We have identified approximately 200 gross drilling locations in our Wilmington field units. Additionally, we have identified approximately 300 gross drilling locations on our acreage in the Rocky Mountains, primarily on 80-acre well spacing.

As of December 31, 2011, we had estimated net proved reserves of 22.3 MMBoe, with a PV-10 value of $526 million, based on a reserve report prepared by Netherland, Sewell & Associates, Inc. These estimated net proved reserves include 15.0 MMBbls in our Wilmington units (67%) and 43.9 Bcfe primarily in our CBM program in the Washakie Basin (33%). These net proved reserves are located on approximately 20% 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.

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As of December 31, 2011, we had interests in 414 gross (206 net) producing wells and are the operator of record or actively participate in the management and operations for 74% 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 2011, our average daily production was 13.7 thousand barrels of oil equivalent per day ("MBoe/d") gross (5.0 MBoe/d net). For 2012, we have a total capital expenditure budget of approximately $79 million.

Our registration statement filed on Form S-1 (SEC File No. 333-118535) for our initial public offering became effective on December 16, 2004. Our common stock commenced trading on the NASDAQ National Market on December 17, 2004 under the trading symbol "WRES". The Company was incorporated on June 12, 1990 as a Delaware corporation for the purpose of acquiring and developing oil & gas properties. In 2004, the Company was reincorporated as a Maryland corporation.

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 seek to maximize the value of our existing asset base by developing properties that have production and reserve growth potential while also attempting to control per unit production costs. We have identified a total of approximately 200 gross oil well drilling locations in our Wilmington Field oil properties and 300 gross drilling locations in our Rocky Mountain CBM properties.

- ***Maximize Production and Increase Proved Developed Producing Reserves from our Existing Oil and Gas Asset Base.*** We intend to increase our proved reserves and production in future years by drilling an increased number of wells on our undeveloped, unproved acreage, which represents approximately 80% of our acreage position at December 31, 2011.

- ***Acquire Additional Resources with an Emphasis on Crude Oil.*** We have been successful in expanding operations through targeted acquisitions in our core areas of expertise. For example, our expertise in waterflood and horizontal drilling lead to 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 ("Anadarko"), one of the largest independent oil and gas exploration and production companies in the world. This strategy allows us to leverage our operating and technical expertise and build on established core operations. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable oil development potential in these regions. We will also continue to evaluate natural gas properties, primarily in our core areas of operation, which can be developed at reasonable costs.

- ***Invest our Capital in a Disciplined Manner and Maintain a Strong Financial Position.*** We focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities in all commodity cycles. Our capital programs are generally developed to be fully funded through internally generated cash flows, but we also may obtain alternative sources of capital investment to develop our assets through partnerships, joint ventures or other investment opportunities with third parties. We hedge a portion of our production and utilize long-term sales contracts whenever possible to maintain a strong financial position and provide the cash flow necessary for the development of our assets.

- ***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. 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.

- ***Control Operations and Costs.*** We seek to serve as the operator of the wells in which we have a significant interest. As the operator, we are better positioned to control the timing and plans for future enhancement and exploitation efforts, the costs of enhancing, drilling, completing and producing the wells, and the marketing negotiations for our gas and oil production to maximize both production volumes and wellhead price.

Business Strengths

Balanced High Quality Asset Portfolio. Since 1999, we have grown our asset base and diversified our production through California oil property acquisitions in the Los Angeles Basin and natural gas properties in the Rocky Mountains that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in natural gas and oil prices as well as area economics.

Long-Lived Proved Reserves with Stable Production Characteristics. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of total proved reserves to production of approximately 13 years.

Low-Risk Multi-Year Drilling Inventory in Established Resource Plays. Most of our drilling locations are located in proven resource plays that possess low geologic risk leading to predictable drilling results. Our California assets where we have identified approximately 200 gross drilling locations have an average depth of less than 4,000 feet and are located in areas where we are an established driller and producer.

Operational control and financial flexibility. As of December 31, 2011, we were the operator of record or actively participate in the management and operations for 74% of our producing wells. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production, and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling budget primarily through our internally generated operating cash flows.

Experienced management and operational teams. Our core team of technical staff and operating managers have broad industry experience, including experience in horizontal and directional drilling, waterflood recovery operations and CBM development and completion. We continue to utilize technologies and waterflood recovery practices that will allow us to optimize production and improve the ultimate recoveries of crude oil on our California properties.

Areas of Exploration and Development Activities

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

Area	Gross Acres	Net Acres	Net Undeveloped Acreage
Atlantic Rim Project, Wyoming	114,919	60,531	48,988
Wilmington Field, California	2,476	2,460	516
Pacific Rim Project, Wyoming	4,818	3,984	3,984
Other(1)	7,375	2,666	1,950
Total	129,588	69,641	55,438

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

California Projects

Wilmington Townlot Unit

Our Wilmington Townlot Unit ("WTU") 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 (1,424 net) acres, has produced more than 149 million barrels of oil from primary and secondary 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 98.9% undivided working interest in the Wilmington Townlot Unit.

During December 2011, we averaged 2,830 barrels of oil per day ("Bbls/d") gross, (2,292 Bbls/d net) production in the Wilmington Townlot Unit, compared to 2,804 Bbls/d gross (2,272, Bbls/d net) production during December 2010. As of December 31, 2011, there were 90 gross (89 net) producing wells. In addition, estimated proved reserves as of December 31, 2011 were 14.5 MMbbls gross (11.8 MMbbls net), of which approximately 60% are proved developed producing ("PDP") or proved developed non-producing ("PDNP") and 40% are proved undeveloped ("PUD"). We seek to develop our PUD reserves using directional and horizontal drilling and secondary recovery techniques, such as a waterflood recovery.

North Wilmington Unit

The North Wilmington Unit ("NWU") 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 84.7% net revenue interest in the North Wilmington Unit field, including existing wells, certain equipment and certain surface properties.

During December 2011, we averaged 385 Bbls/d gross, (326 Bbls/d net) production in the North Wilmington Unit. In addition, estimated proved reserves as of December 31, 2011 were 3.8 MMbbls gross (3.2 MMbbls net), of which 39% are PDPs and 61% are proved undeveloped ("PUD").

Rocky Mountain Projects in the Washakie Basin

Washakie Basin

The Washakie Basin is located in the southeast portion of the Greater Green River Basin in southwestern Wyoming and represents our largest acreage position. As of December 31, 2011, we own 119,737 gross (64,515 net) acres prospective for CBM development in this area, of which 52,972 net acres are undeveloped. This area contains approximately 300 gross identified drilling locations primarily on 80-acre well spacing. The report prepared by Netherland, Sewell & Associates, Inc. as of December 31, 2011 estimates that the gross recoverable proved reserves for the 247 CBM wells drilled and their 46 well offsets in our core CBM project area in this basin were 152 Bcf gross (41.5 Bcf net) on 80-acre well spacing.

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 67,200 gross (60,861 net) undeveloped acres of deep rights inside the area of mutual interest ("AMI") with Anadarko, and approximately 19,873 gross (16,632 net) undeveloped acres of deep rights outside the AMI, for a total of 87,073 gross (77,493 net) undeveloped acres in the entire Atlantic Rim Area.

Commercial CBM production in the Washakie Basin was initially established in 2002 on the eastern rim of the Washakie Basin by Warren and another 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. CBM field development in the Washakie Basin was initiated by grouping wells into "pods" of 10 to 24 wells, complete with associated infrastructure, including water disposal wells, gathering and compression. The productive pods were typically grouped into individual federal units of up to 25,000 acres each, which facilitates development operations. The Bureau of Land Management issued a Record of Decision (ROD) approving the final Atlantic Rim Natural Gas Environmental Impact Statement in May of 2007. This allowed the operators to begin full field development of the Atlantic Rim Project. Partners in the Atlantic Rim plan to develop the core area which is located in the center of the project and develop the field in an outward manner as economics allow.

Atlantic Rim Project

Our Atlantic Rim project comprises approximately 114,919 gross (60,531 net) acres on the eastern rim of the Washakie Basin. As of December 31, 2011, we have drilled a total of 383 wells. Currently, we are developing the majority of our acreage in the Atlantic Rim projects within the area of mutual interest with Anadarko. Anadarko is the operator of record for the Sun Dog and Doty Mountain federal units in 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, with Anadarko having ultimate operator's authority. Warren's interest in the Catalina unit is operated by Double Eagle Petroleum Company.

Spyglass Hill Unit

On June 10, 2011, the U.S. Bureau of Land Management ("BLM") approved the new Spyglass Hill Unit in the Atlantic Rim area. The Spyglass Hill Unit covers approximately 113,000 gross acres and includes the areas previously committed to the Sun Dog, Doty Mountain, Jack Sparrow and Brown Cow Units, as well as all additional leases in the southern portion of the project area. This new unit allows for better location and placement of wells, more efficient development of resources, and increased utilization of existing water and gas transportation infrastructure. Additionally, Warren's leases in this Unit, which are prospective for the deeper Niobrara oil formation, will be protected and perpetuated by Unit operations or production. As anticipated, the BLM requires the drilling of approximately 25 gross (10.3 net) CBM wells per year under the new Spyglass Hill unit agreement. Set forth below are discussions of the three active Sub-Units within the Spyglass Hill Unit: Sun Dog Sub-Unit, Doty Mountain Sub-Unit and Jack Sparrow Sub-Unit. The Catalina Unit is not included within and remains unaffected by the formation of the Spyglass Hill Unit.

Sun Dog Sub-Unit

Our initial pod, the Sun Dog unit, was a 10-well pilot program drilled in 2001 on 80-acre spacing. 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. Currently the Sun Dog unit comprises of 113 wells. During December 2011, production from 79 producing wells averaged approximately 17,900 Mcf/d of gas and 93,000 Bbls/d of water. The wells in Sun Dog are currently being produced at low rates due to water injection capacity constraints in the unit. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2011 estimated proved reserves for the wells in the Sun Dog unit were 59 Bcf gross (20.2 net) Bcf. Estimated gross ultimate recovery for the 113 producing wells and 8 proved undeveloped offset locations in the Sun Dog unit average 0.7 Bcf per well. We currently own a working interest of approximately 42% in the wells drilled in the initial pod of the Sun Dog unit. Our working interest in the unit will be approximately 40% if the existing unit is fully drilled and developed.

Doty Mountain Sub-Unit

The Doty Mountain unit consists of 59 CBM wells on 80-acre spacing. During December 2011, these wells were producing approximately 15,100 Mcf/d of natural gas and 29,000 Bbls/d of water. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2011, estimated proved reserves for the wells in the Doty Mountain unit were 55.5 gross (18.3 net) Bcf. Estimated gross ultimate recovery for the 53 producing wells and 27 proved undeveloped offset locations in the Doty Mountain unit average 0.8 Bcf per well. We currently own an approximate 40% working interest in the wells drilled in the initial pod of the Doty Mountain unit. Our working interest in the unit will be approximately 42% if the existing unit is fully drilled and developed.

Grace Point Sub-Unit (formerly Blue Sky/Jack Sparrow Unit)

The original CBM pilot was a 24-well program originally drilled on 160-acre spacing in 2003 to establish the Blue Sky Unit. During 2005, we drilled 11 additional CBM wells to reduce the well spacing to 80-acres and accelerate de-watering. The Unit was later renamed Jack Sparrow. Based on prior desorption, permeability, pressure build-up and other tests, we believe that as the wells dewater, they should exhibit daily production rates and a CBM production curve similar to other CBM wells in the Atlantic Rim project. However, in early 2009, operations were suspended due to economics and remain shut-in. In 2011 the BLM required a 25 well drilling program in the area, which is now designated the Grace Point Sub-Unit, to establish the larger Spyglass Hill Unit. These 25 wells are currently de-watering and are expected to meet the BLM productivity requirement to validate the Spyglass Hill Unit. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2011, estimated proved reserves for the wells in the Grace Point unit were 1.9 gross (0.7 net) Bcf.

Catalina Unit

The Catalina Unit consists of 71 CBM wells. During December 2011 gross production from the Catalina unit averaged approximately 21,900 Mcf/d of natural gas and 40,000 Bbls/d of water. Warren currently owns a working interest of approximately 8% in the Catalina Unit. Based on a report from Netherland, Sewell & Associates, Inc. as of December 31, 2011 estimated proved reserves for the wells in the Catalina unit were 35.6 Bcf gross (2.3 net) Bcf. Estimated gross ultimate recovery for the 71 producing wells and 11 proved undeveloped offset locations in the Catalina unit average 1.0 Bcf per well. Because we have a larger working interest in the undrilled locations, our working interest in the unit will be approximately 17% if the existing unit is fully drilled and developed.

Niobrara Shale Project

Warren owns certain deep rights below a portion of the Atlantic Rim CBM Project, which include an approximate 77,000 net acre position that is potentially prospective for the Niobrara Shale oil production. The acreage is primarily located in the southern portion of the Eastern Washakie Basin in Wyoming and is adjacent to the Colorado border.

Warren estimates that its Niobrara Shale formation is at depths between 4,000 and 10,000 feet. Successful Niobrara Shale oil wells that have been developed in southern Wyoming and northern Colorado are typically drilled horizontally with multiple-stage fracturing. The Company is also considering possibilities for developing the Niobrara Shale formation, including joint ventures, cooperative development agreements and joint participation agreements.

Oil and Natural Gas Reserves

Third Party Reserve Reporting and Controls Over Reserve Report

Estimates of proved reserves at December 31, 2011 were prepared by Netherland, Sewell & Associates, Inc., our independent consulting petroleum engineers. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. C. Ashley Smith and Mr. Mike Norton. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 2006. Mr. Smith is a Licensed Professional Engineer in the State of Texas (No. 100560) and has over 11 years of practical experience in petroleum engineering, with over 5 years experience in the estimation and evaluation of reserves. He graduated from University of Missouri-Rolla (Missouri University of Science & Technology) in 2000 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Norton has been practicing consulting petroleum geology at NSAI since 1989. Mr. Norton is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 441) and has over 30 years of practical experience in petroleum geosciences, with over 22 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1978 with a Bachelor of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. For the years ended December 31, 2010 and 2009, the Company engaged Williamson Petroleum Consultants, Inc., independent consulting petroleum engineers, to prepare estimates of the Company's proved reserves. The technical persons at Williamson Petroleum Consultants, Inc. responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. These reserves are then reviewed and approved by our in house petroleum engineers and geoscientists who oversee and control preparation of the reserve report by working with the independent consulting petroleum engineers to ensure the integrity, accuracy and timeliness of data furnished to the independent consulting petroleum engineers for their review process. Warren's internal reserve review process is coordinated by a team of six degreed reservoir, drilling, and production engineers and three degreed geologists, who have an average of nearly 20 years of experience in the oil and gas industry. The team is responsible for all technical work to meet the requirements of the SEC and Netherland, Sewell & Associates, Inc., as well as our corporate standards. Warren's technical person who is primarily responsible for overseeing the preparation of our reserve estimates is its Senior Vice President—Development. He has over 32 years of experience in the oil and gas industry, including over 10 years as either a reserve evaluator or manager. His professional qualifications include a bachelor's degree in Chemical Engineering (Petroleum Engineering emphasis), a Masters of Business Administration, licensing as a Registered Petroleum Engineer in the State of California, and membership in the Society of Petroleum Engineers.

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate either negatively or positively. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent that we successfully develop our inventory of probable and possible locations, have positive revisions, acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell & Associates, Inc. and other information about our oil and natural gas reserves, see Note K Oil and Gas Reserve Data (Unaudited) to the Consolidated Financial Statements in Item 8.

The current SEC rules require that the reserve estimates are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2011. For oil volumes, the average Chevron Midway-Sunset posted price of $104.86 per barrel is used for the California properties and the average West Texas Intermediate posted price of $92.71 per barrel is used for all other properties. These average prices are adjusted by lease for quality, transportation fees, and regional price differentials. For gas volumes, the average CIG Rocky Mountains spot price of $3.927 per thousand cubic feet ("Mcf") is used for the Wyoming properties and the average Henry Hub spot price of $4.118 per Mcf is used for all other properties. These average prices are adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant throughout the lives of the properties. All prices and costs associated with operating wells were held constant in accordance with the SEC guidelines.

Proved 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, 2011 based upon reserve reports prepared by Netherland, Sewell & Associates, Inc., and as of December 31, 2010 and 2009 based on reserve reports prepared by Williamson Petroleum Consultants, Inc. The PV-10 values shown

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in the table are not intended to represent the current market value of the estimated natural gas and oil reserves we own.

	Years Ended December 31,		
	2011	2010	2009
Estimated Proved Oil and Natural Gas Reserves:			
Net oil reserves (MBbls):			
Proved developed	8,348	7,518	7,933
Proved undeveloped	6,615	2,732	2,288
Total	14,963	10,250	10,221
Net natural gas reserves (MMcf):			
Proved developed	28,515	49,300	49,868
Proved undeveloped	15,345	18,900	13,032
Total	43,860	68,200	62,900
Total Net Proved Oil and Natural Gas Reserves (MBoe)	22,273	21,617	20,704
Estimated Present Value of Net Proved Reserves:			
PV-10 Value (in thousands)			
Proved developed	$ 359,549	$ 245,306	$ 191,450
Proved undeveloped	166,527	42,322	49,842
Total(1)	526,076	287,628	241,292
Less: future income taxes, discounted at 10%	40,070	—	—
Standardized measure of discounted future net cash flows (in thousands)(2)	$ 486,006	$ 287,628	$ 241,292
Prices Used in Calculating Reserves:			
Oil (per Bbl)	$ 104.75	$ 73.30	$ 54.33
Natural Gas (per Mcf)	$ 3.21	$ 4.13	$ 3.22
Proved Developed Reserves (MBoe)	13,101	15,735	16,244

(1) The PV-10 Value represents the 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 future corporate 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 at December 31, 2011, 2010 and 2009, were determined using average monthly pricing for 2011, 2010 and 2009. These prices reflect adjustment by lease for quality, transportation fees and regional price differences. For 2010 and 2009, there was no income tax effect due to the Company's net loss carry forward for income tax purposes.

(2) Standardized measure of discounted future net cash flows differs from PV-10 value because it includes the effect of future income taxes.

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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, 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 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 future corporate 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.

Oil and gas prices 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 Netherland, Sewell & Associates, Inc., and 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, prices used in computing reserves at December 31, 2011, 2010 and 2009, are based on 12 month average pricing for 2011, 2010 and 2009, respectively.

Productive Wells

The following table sets forth our gross and net productive wells as of December 31, 2011:

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
California	116	115.0	—	—	116	115.0
New Mexico	2	0.03	22	2.3	24	2.3
Texas	—	—	10	2.5	10	2.5
Wyoming	—	—	262	86.0	262	86.0
Other	2	0.1	—	—	2	0.1
Total	120	115.1	120	115.1	414	205.9

Gross wells represent all wells in which we have a working interest. Net wells represent the total of our fractional undivided working interest in those wells. Productive wells include producing wells and wells mechanically capable of production.

Drilling Activity

The following table sets forth the number of gross exploratory and gross development wells drilled in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells completed at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of commercial production.

	Years Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells(1)						
Productive(2)	23	10.0	—	—	—	—
Nonproductive(3)	1	0.5	—	—	—	—
Development Wells(1)						
Productive(2)	20	18.3	10	9.3	1	0.3
Nonproductive(3)	—	—	—	—	—	—
Total	44	28.8	10	9.3	1	0.3

(1) An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. A development well is a well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

(2) A productive well is an exploratory development or extension well that is not a dry 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, 2011:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
California	1,957	1,945	519	515	2,476	2,460
New Mexico	1,066	98	2,924	350	3,990	448
Texas	704	176	—	—	704	176
Wyoming	28,926	11,543	90,812	52,972	119,738	64,515
Other	948	441	1,732	1,601	2,680	2,042
Total	33,601	14,203	95,987	55,438	129,588	69,641

The primary terms of the Company's oil and gas leases expire on various dates in any given year. All of the Company's proved acreage is perpetuated by production, unitization or by continuous operations. This means that the Company will maintain its rights in these leases as long as oil or natural gas is produced from or operations are conducted on the acreage by the Company or other parties holding interests in those leases. In some cases, if production from a lease ceases, the lease will expire, and in other cases, if production from a lease is interrupted or ceases, the Company may maintain the lease by conducting additional operations on the acreage.

Of the Company's non-material leases that are not currently held by production, the Company has approximately 4,450, zero and 12,638 net acres subject to leases with primary terms that expire in 2012, 2013, and 2014, respectively. The Company has in the past been and expects in the future to be able to extend the terms of some of these leases by conducting operations thereon or by exchanging or selling some of these leases to or with other companies. The Company does not expect to lose material lease acreage because of a failure to drill due to inadequate capital, equipment, or personnel. However, based on the Company's evaluation of prospective economics, the Company has allowed acreage to expire and will continue to allow additional acreage to expire in the future.

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. For these purposes, our net production will be production that is owned by us, after deducting royalty, limited partner and other similar interests. The lease operating expenses shown relates to our net production.

	Years Ended December 31,		
	2011	2010	2009
Production:			
Oil (MBbls)	911.4	968.7	952.8
Natural Gas (MMcf)	5,019.6	4,652.5	3,884.8
Total equivalents (MBoe)	1,747.9	1,744.2	1,600.3
Average Sales Price Per Unit:			
Oil (per Bbl)	$ 91.53	$ 71.47	$ 53.93
Natural gas (per Mcf)	$ 3.98	$ 4.09	$ 3.09
Weighted average sales price (per Boe)	$ 59.14	$ 50.61	$ 39.62
Expenses (per Boe):			
Lease operating expense(1)	$ 17.66	$ 16.54	$ 16.93

(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.

Crude Oil and Natural Gas Marketing

We sell our oil and natural gas production to various purchasers in the areas where the oil and natural gas is produced. Our revenues are highly dependent upon the prices of, and demand for, oil and gas. The markets for oil and gas have historically been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including location and quality differentials, seasonality, economic conditions, foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of OPEC, and domestic government regulation, legislation and policies. Decreases in oil and gas prices have had, and could have in the future, an adverse effect on the carrying value and volumes of our proved reserves and our revenues, profitability and cash flow.

We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. Derivatives provide us protection on the sales revenue streams if prices decline below the prices at which the derivatives are set. Our derivative instruments currently consist of crude oil put options entered into with financial institutions.

For 2011, the largest purchasers and marketers of our total oil and gas production were ConocoPhillips, Inc. and Anadarko Energy Services, which accounted for 52% and 38%, respectively, of the total production sold by us.

All of our oil reserves are located in California and are sold into a transportation pipeline which delivers our oil production to ConocoPhillips, Inc., which operates a refinery in nearby Carson, California. All of our oil production in California is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude oil differs from the established market indices in the U.S., due principally to the higher transportation and refining costs associated with heavy oil. Our California crude is sold to ConocoPhillips under a three-year contract which expires on July 31, 2012. This contract provides for a blended pricing with the first 1,800 barrels that we produce sold at 87% of the NYMEX crude oil price and the barrels of oil produced above that amount sold at a daily market price based upon the average of the Midway Sunset price for four major refiners in the area plus a positive adjustment for the gravity of the oil and a positive differential of $0.85 per barrel of oil. For 2011, Warren received a weighted average price of approximately 96% of the NYMEX index price for crude oil sold under the ConocoPhillips contract.

Our natural gas production is delivered into natural gas pipelines for transportation located primarily in Wyoming and New Mexico and is sold to various purchasers for later re-marketing or end use. The majority of all of our natural gas is sold under monthly contracts that allow for periodic adjustments in pricing according to market demands. The prices and marketing of natural gas and oil can be affected by factors beyond our control, the effects of which cannot be predicted, including seasonal variations, general market supply and other fluctuations. In the Atlantic Rim of the Washakie Basin, Wyoming we sell our natural gas at the Rocky Mountain Colorado Interstate Gas ("CIG") market price. The CIG price typically has a negative basis differential below the NYMEX Henry Hub prompt month natural gas price. Fluctuations between spot and index prices can significantly impact the overall differential to the Henry Hub 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. For more information about the risks to our business posed by our marketing activities see "Risk Factors".

Hedging Activities

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price risk. We have an active commodity hedging program to mitigate the risks of the volatile prices of oil and natural gas. Typically, we intend to hedge approximately 40 to 50% of our oil and natural gas production on a forward 12 to 24 month basis using a combination of swaps, cashless collars and other financial derivative instruments with counterparties that we believe are creditworthy. Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While there are many different types of derivatives available, we typically use collar agreements, put options and swap agreements to attempt to manage price risk more effectively. The collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. All collar agreements provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. Under put options, we pay a fixed premium to lock in a specified floor price. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of oil, natural gas, and natural gas liquids for the period is greater or less than the fixed price established for that period when the swap is put in place. If the index price falls below the floor price, the counterparty pays us net of the fixed premium. If the index price rises above floor price, we pay the fixed premium. For additional information on our hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

Our Service and Operational Activities

Our drilling, completion, production, re-entry and land operations are conducted, managed and supervised for us through Warren E&P, Inc., our wholly owned subsidiary ("Warren E&P"). Through Warren E&P, we employ petroleum engineers, geologists, drilling supervisors, landmen and field supervisors. Warren E&P also employs geologists, engineers and other personnel on a contract basis. As of December 31, 2011, Warren E&P was the operator or co-operator of approximately 74% of the wells in which we had interests.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. In general, the bidding for natural gas and oil leases has become particularly intense in the Los Angeles 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. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Regulations and Environmental Matters

General. Our operations are subject to a wide variety of stringent federal, state and local laws and regulations governing the exploration and production of oil and natural gas, including 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 in the areas where we operate. These laws and regulations:

- require the acquisition of various permits before drilling, workovers, or water injection commences;
- require the installation of expensive pollution control equipment;
- restrict the types, quantities and concentration of various substances, including without limitation natural gas and water, that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on lands lying within wildernesses, wetlands and other protected areas;
- require remedial measures to prevent pollution from former operations, such as pit closures and plugging of abandoned wells;
- impose substantial liabilities for pollution resulting from our operations;
- require time consuming environmental analyses with respect to operations affecting federal, state and privately owned lands or leases, 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. These regulations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect. 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 or 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, 2011, we did not incur any material expenditures for remediation or 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 statement, or EIS, that may be made available for public review and comment. All of our current and proposed exploration, production 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 Bureau of Land Management ("BLM") after preparation of an environmental assessment or an environmental impact statement ("EIS"). 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 hold all necessary and up-to-date permits, registrations and other authorizations to the extent our operations require them under such laws and regulations. Although we believe 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 of managing and disposing 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 liabilities, 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 liabilities 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 the EPA or the applicable state agency. These restrictions 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 substantially comply 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. 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 because 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, the 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. Major sources of air pollutants are subject to more stringent, federally based permitting requirements. Because of the severity of ozone levels in portions of California, the state has the most severe restrictions on emissions of volatile organic compounds ("VOCs") and nitrogen oxides ("NOX") of any state. Producing wells, natural gas plants and electric generating facilities all generate VOCs and NOX. Some of our producing wells are in counties that are designated as non-attainment for ozone and, therefore, potentially are subject to restrictive emission limitations and permitting requirements. California also operates a stringent program to control hazardous (toxic) air pollutants, and this program could require the installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits generally are resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could require us to forego construction, modification or operation of certain air-emission sources. Air emissions from oil and natural gas operations also are regulated by oil and natural gas permitting agencies, including in California, the South Coast Air Quality Management District, California Air Resources Board and other local agencies. 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 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 our oil and natural gas projects. See "Wilmington Field" below.

The Safe Drinking Water Act, groundwater protection, and the Underground Injection Control Program

The federal Safe Drinking Water Act (SWDA) and the Underground Injection Control (UIC) program promulgated under the SWDA and state programs regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal permits, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. We engage third parties to occasionally provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Certain states have adopted and are considering laws that require the disclosure of the chemical constituents in hydraulic fracturing fluids. In addition, in 2010, the EPA announced that it would be conducting a study on the environmental effects of hydraulic fracturing. The study is expected to be completed in 2012. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

California Environmental Quality Act ("CEQA"). CEQA is a California statute that requires consideration of the environmental impacts of proposed actions that may affect the environment. CEQA requires the responsible governmental agency to prepare an environmental impact analysis document that is made available for public comment. The responsible agency also is required to consider mitigation measures. The party requesting agency action bears the expense of the document.

In 2011, we received permit approvals from the South Coast Air Quality Management District ("SCAQMD") for the disposal of our WTU associated produced gas allowing us to (i) burn it using a new high efficiency clean enclosed burner to replace the existing gas flare, (ii) inject it in underground formations and (iii) eventually, to sell the gas directly to a nearby public utility or a third party user. In the future, we may be required to undergo the CEQA process for other proposed actions by state and local governmental authorities that meet specified criteria. At a minimum, the CEQA process delays and adds expense to the process of obtaining new permits and permit renewals. See "Wilmington Field" below.

Abandonment, Decommissioning and Remediation Requirements. Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production and transportation facilities and the environmental restoration of operations sites. CSLC and the California Department of Conservation, Division of Oil, Gas and Geothermal Resources ("DOGGR") are the principal state agencies responsible for regulating the drilling, operation, maintenance and abandonment of all oil and natural gas wells in the state.

Significant potential costs relating to environmental and land-use regulations associated with our existing properties and operations include those relating to (i) plugging and abandonment of facilities, (ii) clean-up costs and damages due to spills or other releases, and (iii) penalties imposed for spills, releases or non-compliance with applicable laws and regulations. As is customary in the oil and natural gas industry, we typically have contractually assumed, and may assume in the future, certain obligations relating to plugging and abandonment, clean-up and other environmental costs in connection with our acquisition of operating interests in fields, and these costs can be significant.

Climate Change Legislation and Greenhouse Gas Regulations. Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas ("GHG") emissions that have been or may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of GHG pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA,* that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which allows EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. EPA has begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress has considered and may in the future consider "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The emissions will be published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has issued two other rules that would regulate GHGs, one of which regulates GHGs from stationary sources, and one which requires sources in the oil and natural gas exploration and production industry and the pipeline industry to report GHG emissions. The EPA's finding, the greenhouse gas reporting rules, and the rules to regulate the emissions of greenhouse gases may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

In addition to the EPA's actions to regulate GHGs, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas

Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which establishes a statewide cap on GHGs that will reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. The California Air Resources Board adopted regulations in December 2010 to implement AB 32 by January 1, 2012.

Our operations could be adversely impacted by current and future state and local climate change initiatives.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat, or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communications and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public

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. 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 drilling and production operations are subject to various types of regulation at federal, state and local levels. These types of regulation include requiring permits and bonds for the drilling of wells 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;
- underground injection of water and other substances;
- the surface use and restoration of properties upon which wells are drilled;
- 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 and govern 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 or 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 the 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 services, which occur upstream of jurisdictional transmission services, are 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 transporting gas to point-of-sale locations.

Permits. Our operations are subject to various federal, state and local laws and regulations that include requiring permits for the drilling and operation of wells, maintaining bonding and insurance requirements to drill, operate, plug and abandon, and restore the surface associated with our wells, and 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, the disposal of fluids and solids used in connection with our operations and air emissions associated with our operations. Also, we have permits from numerous jurisdictions to operate crude oil, natural gas and related pipelines and equipment that run within the boundaries of these governmental jurisdictions. The permits required for various aspects of our operations are subject to enforcement for noncompliance as well as revocation, modification and renewal by issuing authorities.

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 Minerals Management Service ("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 requirements concerning permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, 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 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, restrict or regulate 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 our profitability, and we are unable to predict the future cost or impact of complying with such regulations.

Future Regulations

Proposals and proceedings that may affect the oil and gas industry are pending before Congress, BLM, FERC, 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 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.

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 requirements 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 million casualty and environmental insurance policy have been adequate to meet the applicable bonding and insurance requirements to date. Additionally, we have deposited $3.2 million in money market securities as of December 31, 2011, 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 the gas 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.

Atlantic Rim

In May 2007 the BLM issued its Record of Decision for the Atlantic Rim EIS that allows the development of the Atlantic Rim project by drilling up to 2,000 wells, 1,800 of which are CBM wells and 200 of which are deeper conventional wells. Based on the current knowledge of geologic formations, the BLM's minimum well spacing will be 80 acres per CBM well. 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. Disposal of produced water is limited to subsurface injection in the portion of the Washakie Basin within the Colorado River drainage area. We have received permits for a sufficient number of water injection wells in the Atlantic Rim project; however, we will need to obtain permits for additional injection wells, in the event we need additional subsurface disposal capacity.

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, California. 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, curtail or add cost to future Wilmington field development activities. Despite prudent operation and preventative measures, drilling, waterflooding and production operations may result in spills and other accidental releases of produced water, hydrocarbons or injection fluids. Remediation and associated costs from a release of produced water, hydrocarbons 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.

Because the gas volume from the WTU was historically too low to justify gas sales equipment, the gas had been flared for many years under a permit from the SCAQMD. In late 2007, Warren entered into an agreement with the SCAQMD which allowed Warren to commission six microturbines to generate electrical power from the otherwise flared gas and resume full production. As oil production grows, the excess gas produced but not consumed by our microturbines could potentially exceed our current gas flare permit limitation. In March 2008, the Company presented its plan to the SCAQMD to seek approvals from regulatory authorities to dispose of our WTU produced gas by re-injection in underground formations or by selling it directly to a nearby public utility or a third party user. Warren also applied to the SCAQMD for a permit to construct a new high efficiency clean enclosed burner to replace the existing gas flare. Our filed applications for permits request the authority to install and operate certain pieces of new best available control technology ("BACT") equipment. On July 19, 2011 the SCAQMD certified the Company's CEQA documents and issued all of the related permits, including gas handling equipment. These equipment upgrades will help increase the Company's oil processing capability to about 5,000 barrels of oil per day at the Wilmington Townlot Unit. In 2011, Warren installed the high efficiency burner and is actively pursuing permits and agreements necessary to dispose of the associated gas by injecting it in underground reservoirs or selling it to a third party or local utility in the area.

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 certain 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 is usually 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.

Plugging, Abandonment and Remediation Obligations

For discussion of our obligations to incur plugging, abandonment and remediation costs, see Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Commitments and Contingencies.

Employees

At December 31, 2011, 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.

Offices

Our principal executive offices are located at 1114 Avenue of the Americas, 34th Floor, New York, NY 10036, and our telephone number is (212) 697-9660. We lease approximately 4,178 square feet of office space for our New York office under a lease that expires in January 2014. Our oil and gas operations office in Casper, Wyoming occupies 5,554 square feet under a lease that expires in July 2012. Our oil and gas operations office in Long Beach, California occupies 14,201 square feet of space under a lease that was entered into in February 2012, which expires in April 2020. In June 2010, we entered into an office lease in Roswell, New Mexico, which expires in May 2013. We believe that suitable additional space to accommodate our anticipated growth will be available in the future on commercially reasonable terms.

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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 1114 Avenue of the Americas, 34th Floor, New York, NY 10036.

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, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

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. An exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

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 a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Farm-out 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 to 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 building, 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.

Oil. Crude oil, condensate and natural gas liquids.

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.

Pay zone. A geological deposit in which oil and natural gas is found in commercial quantities.

PDNP. Proved developed nonproducing.

Productive Well. An exploratory, development, or extension well that is not a dry well.

Proved developed non-producing reserves. Proved developed reserves that do not qualify as proved developed producing reserves, including reserves that are expected to be recovered from (i) completion intervals that are open at the time of the estimate, but have not started producing, (ii) wells that are shut in because pipeline connections are unavailable or (iii) wells not capable of production for mechanical reasons.

PDP. Proved developed producing.

Proved developed producing reserves. Reserves that are being recovered through existing wells with existing equipment and operating methods.

Proved developed reserves. This term means "proved developed oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X, and refers to reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves or proved oil and gas reserves. This term means "proved oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X and refers to the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved undeveloped reserves or PUDs. Undeveloped reserves that qualify as proved reserves.

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

Proved reserves. This term means "proved oil and gas reserves" as defined in Rule 4-10 of SEC Regulation S-X and refers to the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved undeveloped reserves. 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 PV-10 of reserves is the present value of estimated future revenues to be generated from the production of the reserves net of estimated production and future development costs and future plugging and abandonment costs, using the twelve-month arithmetic average of the first of the month prices (except that for periods prior to December 31, 2009, the period end price was used), without giving effect to hedging activities or future escalation, costs as of the date of estimate without future escalation, without non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion, amortization and impairment and 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.

Reserves. This term is defined in Rule 4-10 of SEC Regulation S-X and refers to estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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.

Shut in. A well suspended from production or injection but not abandoned.

Spacing. The number of wells which can be drilled on a given area of land under applicable laws and regulations.

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on prices used in estimating the reserves, year-end costs, and statutory tax rates, and a ten percent annual discount rate. The information for this calculation is included in the note regarding disclosures about oil and gas producing activities contained in the Notes to Consolidated Financial Statements included in this Form 10-K.

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.

Workover. Remedial operations on a well conducted with the intention of restoring or increasing production from the same zone, including by plugging back, squeeze cementing, reperforating, cleanout and acidizing.

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 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 the Oil and Natural Gas Industry and Our Business

Oil and natural gas prices are volatile. Volatility in oil and natural gas prices can adversely affect our results and the price of our common stock. This volatility also makes valuation of natural gas and oil producing properties difficult and can disrupt markets.

Oil and natural gas prices have historically been, and are likely to continue to be, volatile. Oil and natural gas prices are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. Some of the factors that cause these fluctuations are:

- demand for oil and gas, which is affected by worldwide population growth, economic development and general economic and business conditions;
- the domestic and foreign supply of oil and natural gas;
- political and economic uncertainty and socio-political unrest;

- the price of foreign imports;
- political and economic conditions in oil producing countries, especially the Middle East and South America;
- the ability of the Organization of Petroleum Exporting Countries ("OPEC") to set and maintain oil price and production controls;
- the level of domestic and international exploration, drilling and production activity;
- the cost of exploring for, producing and delivering oil and gas;
- weather conditions and changes in weather patterns;
- the price and availability of, and demand for, competing energy sources, including liquefied natural gas, and alternative energy source;
- technological advances affecting energy consumption;
- the nature and extent of governmental regulation and taxation, including environmental regulations;
- availability, proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of alternative energy; and
- variations between product prices at sales points and applicable index prices.

Additionally, continuance of the current low natural gas price environment, further declines in natural gas prices, lack of natural gas storage may have the following effects on our business:

- reduction of our revenues, operating income and cash flows;
- curtailment or shut-in of our natural gas production due to lack of transportation or storage capacity;
- cause certain properties in our portfolio to become economically unviable;
- cause significant reductions in our capital investment programs, resulting in a failure to develop our natural gas reserves;
- limit our financial condition, liquidity, and/or ability to finance planned capital expenditures and operations;

The long-term effects of these and other conditions on the prices of crude oil and natural gas are uncertain. Price volatility makes it difficult to budget and project the return on exploration and development projects involving our natural gas and oil properties and to estimate with precision the value of producing properties that we may own or propose to acquire. In addition, unusually volatile prices often disrupt the market for natural gas and oil properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Our cash flow and results of operations depend to a great extent on the prevailing prices for crude oil and natural gas. Our annual and quarterly results of operations may fluctuate significantly as a result of, among other things, variations in natural gas and oil prices and production performance. In recent years, natural gas and oil price volatility has become increasingly severe.

A decline in oil and natural gas prices would adversely affect our ability to meet our capital expenditure obligations, financial commitments, financial results, cash flows, access to capital and ability to grow.

Our revenues, operating results, cash flow, profitability and future rate of growth depend upon the prevailing prices of, and demand for, natural gas and oil. All of our operating revenues are derived from the sale of our oil and gas production. A continuing substantial or extended decline in oil and natural gas prices would have a material adverse effect on our financial position, our ability to meet capital expenditure obligations and commitments, our results of operations, our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period negatively affects us in several ways including:

- our cash flow will be reduced, decreasing funds available for capital investments employed to replace reserves, increase production or to operate;
- certain reserves will no longer be economic to produce, leading to both lower proved reserves and cash flow and may result in charges to earnings for impairment of the value of these assets; and
- access to other sources of capital, such as bank loans, equity or debt markets, could be severely limited or unavailable.

Based on crude and natural gas pricing in recent years, the Company's oil and gas revenues may from time to time decrease, resulting in a negative impact on liquidity. The Company's current plans to address lower crude and natural gas prices are primarily to reduce capital expenditures to a level equal to cash flow from operations, reduce operating expenses and seek additional capital financing. However, the Company's plans may not be successful in improving its results of operations and liquidity. If oil or natural gas 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, which could impair our liquidity and our ability to develop our properties and to operate.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Future deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

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, or 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, permit, 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. Compliance costs are significant. The exploration and production of oil and gas involves many risks concerning equipment and human operational problems that could lead to leaks or spills of petroleum products. These laws and regulations, particularly in the California and Rocky Mountain regions, are extensive and involve severe penalties and could change in ways that substantially increase our costs and associated liabilities.

As a result, there can be no assurance that our anticipated production levels will be realized or that our estimates of proved reserves will not be negatively impacted. For example, during the first half of 2011, WTU oil production decreased primarily due to the inability to drill new water injection wells pending the receipt of permits from the California Division of Oil, Gas and Geothermal Resources ("DOGGR"). The DOGGR has continued to be slow to approve certain new injection permits and as a result we are unable to determine the pace we can develop the WTU until such permits are issued.

Part of the regulatory environment in which we operate includes, in some cases, federal and state 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 may hinder or limit the quantity of oil and natural gas we may be able to produce and sell.

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 for producing and water injection wells, 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 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. Conditions, delays or restrictions imposed on the management of groundwater produced during drilling could severely limit our operations or make them uneconomic. Any unfavorable developments in the Wilmington Townlot Unit could impede our growth, as we intend to undertake significant activity in order to increase our production and reserves in this area.

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:

- drilling permits;
- water discharge and disposal permits for drilling operations;
- the amounts and types of substances and materials that may be released into the environment;
- drilling and operating bonds;
- environmental matters and reclamation;
- spacing of wells;
- the permitting and use of underground injection wells, which affects the disposal of water from our 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 or disposal 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 "Items 1 and 2: Business and Properties—Regulations and Environmental Matters" and "Item 3:—Legal Proceedings" for a more detailed discussion of laws affecting our operations.

Changes in applicable laws and regulations could increase our costs, reduce demand for our production, impede our ability to conduct operations or have other adverse effects on our business.

Future changes in the laws and regulations to which we are subject may make it more difficult or expensive to conduct our operations and may have other adverse effects on us. For example, the EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other greenhouse gases ("GHG") present an endangerment to human health and the environment, which allows the EPA to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has recently begun to implement GHG-related reporting and permitting rules. Similarly, the U.S. Congress is considering "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. On September 27, 2006, California's governor signed into law Assembly Bill (AB) 32, known as the "California Global Warming Solutions Act of 2006," which establishes a statewide cap on GHGs that will reduce the state's GHG emissions to 1990 levels by 2020 and establishes a "cap and trade" program. The California Air Resources Board has been designated as the lead agency to establish and adopt regulations to implement AB 32 by January 1, 2012. Similar regulations may be adopted by the federal government. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Reform Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through implementing regulations to be adopted by the SEC, the Commodities Futures Trading Commission and other regulators. If, as a result of the Reform Act or its implementing regulations, additional capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and natural gas properties and other assets, would likely make it impracticable to implement our current hedging strategy or to meet the hedging requirements contained in our revolving credit facility. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy.

In addition, some of our activities involve the use of hydraulic fracturing, which is a process that creates a fracture extending from the well bore in a rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Fractures are typically created through the injection of water and chemicals into the rock formation. Legislative and regulatory efforts at the federal level and in some states have been made to render permitting and compliance requirements more stringent for hydraulic fracturing. These proposals, if adopted, would likely increase our costs and make it more difficult, or impossible, to pursue some of our development projects.

We could also be adversely affected by future changes to applicable tax laws and regulations. For example, proposals have been made to amend federal and/or California State and local laws to impose "windfall profits," severance or other taxes on oil and natural gas companies. If any of these proposals become law, our costs would increase, possibly materially. Significant financial difficulties currently facing the State of California and localities may increase the likelihood that one or more of these proposals will become law. For example, in California, there have been proposals at the legislative and executive levels over the past two years for tax increases which have included a severance tax as high as 12.5% on all oil production in California. Although the proposals have not passed the California Legislature, the financial crisis in the State of California could lead to a severance tax on oil being imposed in the future

President Obama has made proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

We have incurred losses and may do so in the future.

At December 31, 2011, we had an accumulated deficit of $290.6 million and total stockholders' equity of $174.1 million. We have recognized a significant amount of annual net losses in the past. See "Item 6: Selected Consolidated Financial Data". The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit and acquire natural gas and oil reserves. We may not achieve or sustain profitability or positive cash flows from operating activities in the future.

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

No one can measure underground accumulations of oil and natural gas in an exact way. There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, operating and development costs, drilling expenses, severance and excise taxes, capital expenditures, ownership and title matters, taxes and the availability of funds. The engineering process of estimating natural gas and oil reserves is complex and is not an exact science. It requires interpretations of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Estimates of reserves based on risk of recovery and estimates of expected timing and future net cash flows prepared or audited by different engineers, or by the same engineers at different times, may vary substantially. Because of the subjective nature of crude oil and natural gas reserve estimates, each of the following items may differ materially from the amounts or other factors estimated:

- The amount and timing of crude oil and natural gas production.
- The revenues and costs associated with that production.
- The amount and timing of future development expenditures.

Over time, our independent petroleum engineering consultants may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. Further, the potential for future reserve revisions, either upward or downward, is significantly greater than normal because a significant portion of our potential reserves are undeveloped.

In accordance with SEC requirements, our estimates of proved reserves for 2011 are determined based on a historical 12-month average price as of the first day of each month during the fiscal year. Any significant variance from these prices and costs could greatly affect our estimates of reserves. In addition, proved undeveloped reserves locations to limited to those scheduled to be drilled within the next five years

As of December 31, 2011 and 2010, approximately 41% and 27%, respectively, 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. Additionally, as oil and gas commodity prices become lower, the quantity of economically recoverable proved reserves declines. 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.

Actual natural gas and oil prices, future production, revenues, operating expenses, taxes, development expenditures and quantities of recoverable natural gas and oil 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.

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.

The geographic concentration and characteristics of our oil reserves may have a greater effect on our ability to sell our oil production.

All of our oil reserves are located in California. Any regional events, including price fluctuations, natural disasters and restrictive regulations that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than if our reserves were more geographically diversified.

Our California oil production is, on average, heavier than premium grade light oil and the margin (sales price minus production costs) is generally less than that of lighter oil sales due to the processes required to refine this type of oil and the transportation requirements. As such, the effect of material price decreases will more adversely affect the profitability of heavy oil production compared with lighter grades of oil.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2011, we own leasehold interests in approximately 52,972 net acres in areas in the Washakie Basin of Wyoming that we believe may be prospective for the CBM and approximately 77,000 net acres in areas we believe may be prospective for the Niobrara Shale. A large portion of our acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, approximately 4,450 net acres of these leases will expire in 2012. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and there is therefore additional risk of expirations occurring in sections where we are not the operator.

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 depends in part on the evaluation of geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our costs of drilling, completing, producing and operating wells are often uncertain before drilling commences. Drilling for oil and natural gas can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- delays in obtaining drilling permits from applicable regulatory authorities;
- unusual or unexpected geological formations;
- unexpected drilling conditions, including ground shifting or quakes;

- pressure or irregularities in geological formations;
- equipment failures or accidents;
- well blow-outs;
- fires and explosions;
- pipeline and processing interruptions or unavailability;
- title problems;
- objections from surface owners and nearby surface owners in the areas where we operate;
- 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 or delivery 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 could decline generally or within a particular area and we could incur losses by drilling unproductive wells. Also, we may not be able to obtain sufficient 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.

All of our oil production is dedicated to one customer and as a result, our credit exposure to this customer is significant.

We have entered into an oil marketing arrangement with ConocoPhillips under which ConocoPhillips purchases all of our net oil production in California. We generally do not require letters of credit or other collateral to support these trade receivables. Accordingly, a material adverse change in their financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

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. As of December 31, 2011, we had $89.5 million in principal amount of senior indebtedness outstanding under our secured revolving bank Credit Facility and our available borrowing base was $130 million. Our Credit Facility restricts our ability to obtain additional financing, make investments, pay dividends, lease equipment, sell assets and engage in business combinations. We also are, and will continue to be, required to comply with certain financial covenants and ratios. The Credit Facility contains affirmative and negative covenants, including the following financial maintenance covenants: an EBITDAX to interest coverage ratio for any period of four consecutive fiscal quarters to be not less than 2.5 to 1.0, determined as of the last day of each fiscal quarter; and a minimum current ratio of current assets (including availability under the Credit Facility) to current liabilities of not less than 1.0 to 1.0. At December 31, 2011, the Company was in full compliance with the covenants and other provisions of the Credit Facility.

In addition to those described above, other factors may impair the Company's ability to comply with the covenants. Any failure to be in compliance with any material provision or covenant of the Credit Facility could result in a default, which could have a material adverse effect on our liquidity, results of operations and financial condition. At certain oil and natural gas price levels, the Company's current cost structure, inclusive of our current plans, may exceed the costs required to operate profitably. 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 contained in the Credit Facility could result in a default under the facility, which could cause all of our existing indebtedness to become immediately due and payable.

Our Credit Facility limits the funds 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. In addition, under the terms of our credit facility, our borrowing base is subject to redeterminations at least semiannually on April 1 and October 1 of each year based in part on prevailing natural gas and oil prices. 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 100% 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. In the event the borrowed amount outstanding exceeds the re-determined borrowing base, we could be forced to repay a portion of our borrowings. If lower oil and natural gas commodity prices occur, our borrowing base may be lowered by the lenders upon a future borrowing base re-determination. 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, in order to prevent a default we may have to sell a portion of our assets. If we cannot timely sell a portion of our assets under such circumstances, the lenders could declare the Credit Facility in default, which could cause all of our existing indebtedness to be immediately due and payable.

Our Credit Facility is secured by a pledge of substantially all of our producing natural gas and oil properties and assets, is guaranteed by our subsidiaries, 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 the 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 in 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 or covenants, and could require us to modify our operations, including 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 be required to 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.

We are subject to the full cost ceiling limitation which may result in a write-down of our estimated net reserves in the future.

We utilize the full cost method of accounting for costs related to our natural gas and oil properties. Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a write-down of our net oil and gas properties to the extent of such excess. A capitalized cost ceiling test impairment also reduces earnings and impacts stockholders' equity in the period of occurrence and results in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. For 2011, 2010 and 2009, there was no ceiling test impairment on our oil and gas properties.

The risk that we will be required to write down the carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments in our estimated proved reserves, or if purchasers cancel long-term contracts for our natural gas production. An expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the applicable ceiling in the subsequent period. This and other factors could cause us to write down our natural gas and oil properties or other assets in the future and incur a non-cash charge against future earnings.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We spend and will continue to need a substantial amount of capital for the acquisition, exploration, exploitation, development and production of oil and gas reserves. We have historically addressed our short and long-term liquidity needs through the use of cash flow provided by operating activities, borrowing under bank credit facilities, and the issuance of equity and debt securities. Without adequate financing we may not be able to successfully execute our operating strategy. The availability of these sources of capital will depend upon a number of factors, some of which are beyond our control. These factors include:

- general economic and financial market conditions;

- oil and natural gas prices;
- our market value and operating performance;
- 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;
- amounts of necessary working capital and expenses; and
- the level of production from existing and new wells.

We may be unable to execute our operating strategy if we cannot obtain adequate capital. If low oil and natural gas prices, lack of adequate gathering or transportation facilities, operating difficulties or other factors, many of which are beyond our control, cause our revenues and cash flows from operating activities to decrease, it may limit or reduce our borrowing base under our credit facility, and therefore, limit our ability to obtain the capital necessary to sustain our operations.

Additional financing sources may be required in the future to fund our developmental and exploratory drilling. Our Credit Facility restricts our ability to obtain new financing. There can be no assurance as to the availability or terms of any additional financing. 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;
- becoming 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 the 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 operations, or be forced to sell some of our assets on an untimely or unfavorable basis, or face a possible loss of properties and a decline in our oil and natural gas reserves, which would have an adverse affect on our business, financial condition and results of operations.

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. Our future success depends on our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when production occurs unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not be able to find, develop or acquire additional reserves on an economic basis. Furthermore, if oil and natural gas prices increase, our costs for additional reserves could also increase. 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, finance or acquire additional reserves to replace our current and future production at acceptable costs.

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 expenses, and drilling and production 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.

We face significantly increasing water injection and disposal regulations and costs in our drilling operations.

In California, as part of our waterflood development plan for the WTU and NWU, over the next 3 - 5 years we will require 30 - 50 water injection well approvals from the California DOGGR. We believe that due to the DOGGR's personnel constraints and new more rigid review and interpretation procedures, water injection permits have been taking longer than previous permits. During 2011, Warren only received one water injection permit for a WTU Tar formation well. Further, due to the volume of water being injected into the Upper Terminal formation and the corresponding rise in reservoir pressure, during 2011, we have elected to temporarily shut-in approximately 300 net BOPD (approximately 110,000 barrels of oil annually) from lower producing, higher water-cut wells, until additional water injection well permits are obtained for the Tar and Ranger formations. Additionally, as a result of the delay in receiving water injection permits, the reservoir pressure in the Tar formation has dropped, resulting in a steeper production decline. A new head of DOGGR was appointed in November 2011, and since then DOGGR has switched to a more practical, risk-based evaluation, resulting in timelier reviews of applications for injection permits. In January 2012, Warren received 5 permits for water injection wells in its WTU Upper Terminal formation. We cannot be certain, however, of when DOGGR will issue the other WTU water injection permits for our other pending applications.

The Wyoming Department of Environmental Quality, or Wyoming DEQ, has restrictive regulations applicable 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, we believe that permits for surface discharge of produced water in the Washakie Basin will become difficult to obtain. In Wyoming, our produced water is currently re-injected into water disposal wells.

We expect the regulation and 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.

We face increasing natural gas disposal regulations and costs in our Wilmington oil operations that could limit our oil production.

The State of California and the EPA have restrictive regulations for the disposition of natural gas produced from our Wilmington oil drilling operations. Natural gas production has continued to grow with the oil production, particularly at the WTU. Because the gas volume from the WTU was historically too low to justify gas sales equipment, the gas has been flared for many years under a permit from the SCAQMD. In late 2007, Warren entered into an agreement with the SCAQMD which allowed Warren to commission six microturbines to generate electrical power from the otherwise flared gas and resume full production. As oil production grew since that time, the excess gas produced but not consumed by our microturbines could have exceeded our gas flare limitation. In March 2008, the Company presented its plan to the SCAQMD to seek approvals from regulatory authorities to dispose of our WTU produced gas by re-injection in underground formations or by selling it directly to a nearby public utility or a third party user. Warren also applied to the SCAQMD for a permit to construct a new high efficiency clean enclosed burner to replace the existing gas flare. Our filed applications for permits request the authority to install and operate certain pieces of new best available control technology equipment. On July 19, 2011 the SCAQMD certified the Company's CEQA documents and issued all of the related permits, including gas handling equipment. These equipment upgrades will help increase the Company's oil processing capability to a ceiling of 5,000 barrels of oil per day at the Wilmington Townlot Unit. Delays by regulatory agencies in approving our permits in the future to dispose of the natural gas could limit our future oil production levels until the permits are issued.

See "Items 1 and 2: Business and Properties—Future Regulations—*Wilmington Field*"

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. Also, as production volumes grow in the Atlantic Rim, additional pipeline capacity and gas compression will be required.

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 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, taxation 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 to obtain adequate natural gas prices. 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 could be made to deliver our production to market.

We may be affected by climate change and market or regulatory responses to climate change

Climate change, including the impact of global warming, could have a material adverse effect on our results of operations, financial condition, and liquidity. Restrictions, caps, taxes, or other controls on emissions of greenhouse gasses, including exhaust from generators, engines and flaring of excess natural gas, could significantly increase our operating costs. Restrictions on emissions could also affect our customers that (a) use oil and gas to produce energy, or (b) manufacture or produce goods that consume significant amounts of energy or burn fossil fuels, including chemical producers, farmers and food producers, and automakers and other manufacturers. Significant cost increases, government regulation, or changes of consumer preferences for goods or services relating to alternative sources of energy or emissions reductions could materially affect the markets for the oil and gas commodities, which in turn could have a material adverse effect on our results of operations, financial condition, and liquidity. Government incentives encouraging the use of alternative sources of energy could also affect certain of our oil and gas commodity purchasers and the markets for certain of the commodities in an unpredictable manner, including, for example, the impacts of ethanol incentives on farming and ethanol producers and tax credits for wind turbine and solar power generation. Finally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change. Any of these factors, individually or in operation with one or more of the other factors, or other unforeseen impacts of climate change could reduce the demand for oil and gas commodities and have a material adverse effect on our results of operations, financial condition, and liquidity.

Our hedging activities could result in financial losses or could reduce our income.

To achieve a more predictable cash flow, to reduce our exposure to adverse fluctuations in the prices of oil and natural gas and to comply with credit agreement requirements, we currently, and may in the future, enter into hedging arrangements for a portion of our oil and natural gas production. Hedging arrangements for a portion of our oil and natural gas production expose us to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the hedging contract defaults on its contractual obligations; or
- there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received.

In addition, these types of hedging arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

The risk that a counterparty may default on its obligations is heightened by the recent sub-prime mortgage losses incurred by many banks and other financial institutions, including our counterparties or their affiliates. These losses may affect the ability of the counterparties to meet their obligations to us on hedge transactions, which would reduce our revenues from hedges at a time when we are also receiving a lower price for our natural gas and oil sales. As a result, our financial condition could be materially or adversely affected.

We have elected not to designate our commodity derivatives as cash flow hedges for accounting purposes. Accordingly, such contracts are recorded at fair value on our Balance Sheet and changes in fair value are recorded in the Consolidated Statements of Operations as they occur.

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 fund our operations, 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. If we are unable to repay our debt at maturity with existing 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, our market value and profitability of our operations at the time of the offering or other financing. If we do not have sufficient funds, 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 may not be completely accurate. Generally, it 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 fully assess 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 properties we acquire.

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 can be 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 in difficult terrain. Primarily in the winter and spring, our operations are often curtailed because of cold, snow and wet conditions, as well as lease stipulations. 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.

See "Items 1 and 2: Business and Properties—Glossary of Abbreviations and Terms—Identified drilling locations".

As co-venturer in joint ventures, we are liable for various obligations of those joint ventures.

As a co-venturer, we are contingently liable for the obligations of the joint venture, including responsibility for day-to-day operations and liabilities which cannot be repaid from joint venture assets, insurance proceeds or indemnification by others. In the future, we might be exposed to litigation in connection with joint venture activities, or find it necessary to advance funds on behalf of 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.

Our role as 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 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 key personnel could adversely affect our business.

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business, and we do not maintain key man insurance on the lives of many of these persons.

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, Steve Heiter, our executive vice president and CEO of our operating subsidiary, Warren E&P, Inc., and other key management and technical personnel. We maintain key person life insurance on Messrs. Swanton, Larkin and Heiter but generally not on other key management and technical personnel.

Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete 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 various lawsuits, which may not be fully covered by our insurance.

Our insurance coverage does not cover all potential risks, losses, costs, or liabilities. We ordinarily maintain insurance against various losses and liabilities arising from our operations in accordance with customary industry practices and in amounts that management believes 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. Business disruptions could seriously harm our future revenue and financial condition and increase our costs and expenses. Our operations could be subject to earthquakes, mudslides, fires, power shortages, telecommunications failures, water shortages, floods, hurricanes, extreme weather conditions and other natural or manmade disasters or business interruptions, for which we are predominantly self-insured. The occurrence of any of these business disruptions could seriously harm our revenue and financial condition and increase our costs and expenses. Our Long Beach, California regional operations and a substantial portion of oil properties are located in southern California near major earthquake faults. Our revenues and income could be adversely affected if our operations in these locations are disrupted for any reason, including natural disasters, environmental, public health, or political issues. The ultimate impact on us of being located near major earthquake faults and being consolidated in certain geographical areas is unknown, but our revenue, profitability and financial condition could suffer in the event of a major earthquake or other natural disaster.

Our natural gas and oil exploration and production activities are subject to numerous hazards and risks associated with drilling for, operating, 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 and ground subsidence;
- mechanical difficulties, inadequate oil field drilling and service tools, and casing collapses;
- fires and explosions;
- personal injuries and death;
- labor and employment;
- regulatory investigations and penalties; and
- natural disasters, such as earthquakes, hurricanes and floods.

Any of these risks could have a material adverse effect on our ability to conduct operations or result in substantial losses to us. Many of these risks are not insured as the cost of available insurance, if any, is excessive. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs that is not fully covered by insurance, it could have a material adverse effect on our business, financial condition and results of operations. See "Items 1 and 2: 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 or other agreements under which we own partial ownership or working 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 or quitclaim or without any warranty. We acquired our interests in the Wilmington Townlot Unit in 1999 and 2005 with no title opinion as to the interests acquired, 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 acquired. The prior owner had owned the North Wilmington Unit for over 15 years, acquired the North Wilmington Unit from Sun Oil Corporation without warranty of title, which had owned unit for over 20 years before its sale in 1990. Losses of title to the Wilmington Townlot Unit or 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 title to some or all of the properties we 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.

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

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.

Competition in the oil and natural 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 highly competitive areas of oil and natural 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, personnel 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 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.

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

If domestic drilling activity increases, particularly in the fields in which we operate, a general shortage of drilling and completion rigs, field equipment and qualified personnel could develop. As a result, the costs and delivery times of rigs, equipment and personnel could be substantially greater than in previous years. From time to time, these costs have sharply increased and could do so again. 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. Although Warren owns a drilling rig for use in the WTU, 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.

Increases in taxes on energy sources may adversely affect the company's operations.

Federal, state and local governments which have jurisdiction in areas where the company operates impose taxes on the oil and natural gas products sold. Historically, there has been an on-going consideration by federal, state and local officials concerning a variety of energy tax proposals. As an example, there is a new proposal in California to impose a 12.5% severance tax on oil produced in California, which requires a majority vote in 2012 by the citizens of California. Such matters are beyond the company's ability to accurately predict or control.

Computer security breaches and other disruptions could compromise our information and expose us to liability, which would cause our business and reputation to suffer.

In the ordinary course of our business, Warren collects and stores sensitive data, including intellectual property, its proprietary business information, information about its customers, suppliers and business partners, and personally identifiable information about its oil and gas lease lessors/royalty holders and its employees in our computer data centers and on our networks. The secure processing, maintenance and transmission of this information is critical to our operations. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, and regulatory penalties, disrupt our operations, and damage our reputation, which could adversely affect our business.

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, 2011, we had 71,518,810 shares of common stock outstanding, 52,522 shares of common stock were issuable upon conversion of our convertible debt and convertible preferred stock, 3,092,985 shares of common stock were issuable upon exercise of outstanding options, and 615,731 shares of restricted stock are issuable upon vesting. 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 has been and 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 has and may continue to experience volatility unrelated to our 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 or period;
- changes in expectations of 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 and compliance with environmental and other governmental rules and 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.

Many of these factors are beyond our control, and we cannot predict their potential effects on the price of our common stock. We cannot assure you that the market price of our common stock will not fluctuate or decline significantly in the future. In addition, the stock markets in general can experience considerable price and volume fluctuations.

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 6, 2012, 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;
- prohibiting cumulative voting in the election of directors; and

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.

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.

We make estimates and assumptions in connection with the preparation of Warren's Consolidated Financial Statements, and any changes to those estimates and assumptions could have a material adverse effect on our results of operations.

In connection with the preparation of Warren's Consolidated Financial Statements, we use certain estimates and assumptions based on historical experience and other factors. Our most critical accounting estimates are described in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report. In addition, as discussed in Note A to the Consolidated Financial Statements, we make certain estimates, including decisions related to provisions for legal proceedings and other contingencies. While we believe that these estimates and assumptions are reasonable under the circumstances, they are subject to significant uncertainties, some of which are beyond our control. Should any of these estimates and assumptions change or prove to have been incorrect, it could have a material adverse effect on our results of operations.

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.

None.

Item 2: Properties

A description of our properties is included in Items 1 and 2. Business and Properties above and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future

Item 3: Legal Proceedings

Information with respect to this item may be found in Note F Commitments and Contingencies to the Consolidated Financial Statements in Item 8, which is incorporated herein by reference.

Item 4: Mine Safety Disclosures

Not applicable.

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, 2011		
First Quarter	$ 5.94	$ 4.01
Second Quarter	5.13	3.40
Third Quarter	4.43	2.38
Fourth Quarter	3.37	2.13
Year Ended December 31, 2010		
First Quarter	$ 2.66	$ 2.20
Second Quarter	3.65	2.50
Third Quarter	3.98	2.86
Fourth Quarter	4.70	3.85

On March 1, 2012, the closing sales price for our common stock as reported by the NASDAQ Global Market was $3.96 per share.

Holders

As of March 1, 2012 there were approximately 2,142 holders of our common stock.

Dividend Policy

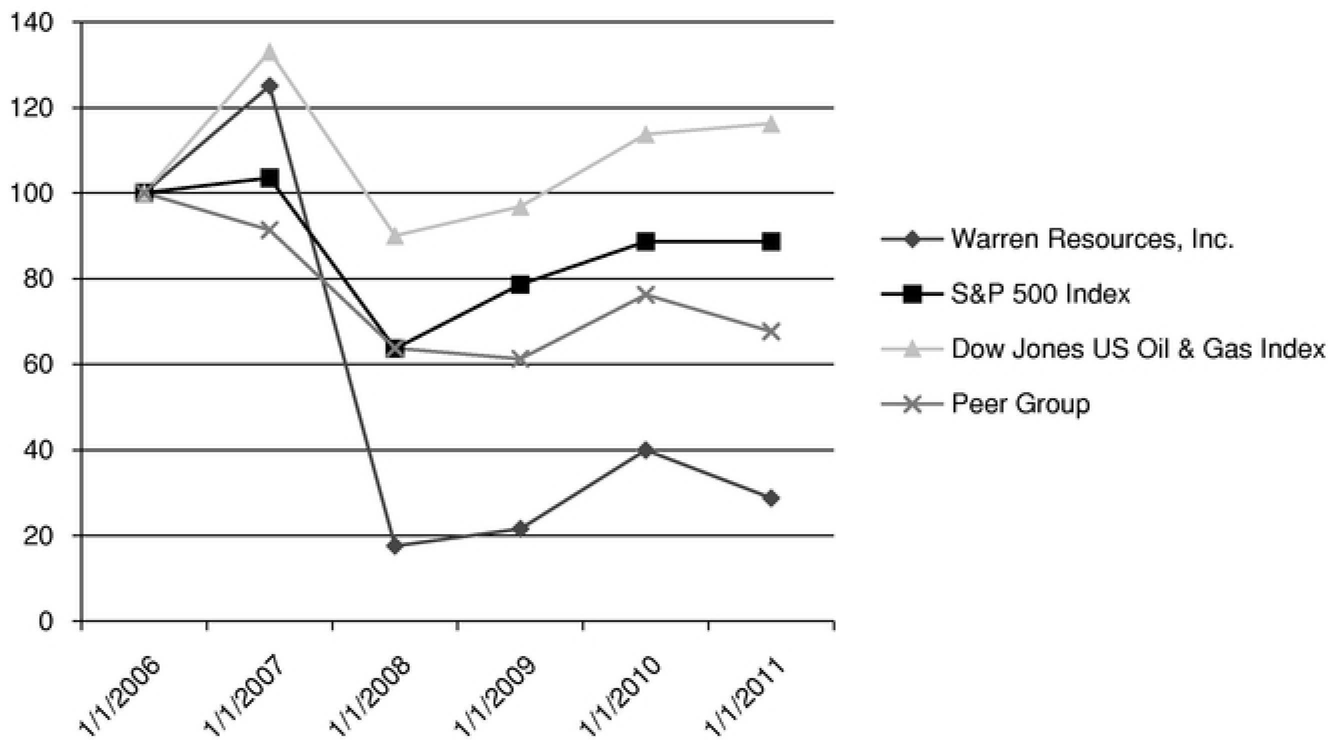
We have never paid or declared any cash dividends on our common stock. We currently intend to retain earnings, if any, to finance the growth and development of our business and we do not expect to pay any cash dividends on our common stock in the foreseeable future. Payment of future cash dividends, 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 common stock performance graph shows the performance of Warren Resources common stock through December 31, 2011. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

- A $100 investment was made in Warren common stock and each index on December 31, 2006.
- All dividends were reinvested at the average of the closing stock prices at the beginning and end of the quarter

The indices in the 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 each year since December 31, 2006, 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, and a peer group index comprised of 8 United States companies engaged in oil and natural gas operations whose stocks were traded on the NASDAQ or the NYSE during the period from December 31, 2006 through December 31, 2011. The companies that comprise the peer group are Abraxas Petroleum Corporation, Berry Petroleum Corp., Callon Petroleum Corp., Goodrich Petroleum Corporation, Harvest Natural Resources, Inc., Petroleum Development Corp., PetroQuest Energy, Inc., and PrimeEnergy Corporation, which companies have market capitalizations similar to Warren and are primarily involved in domestic U.S. exploration and production.



Fiscal Year Ended December 31
(in US Dollars)

	2006	2007	2008	2009	2010	2011
Warren Resources, Inc.	100	125	17.60	21.60	40.00	28.80
S&P 500 Index	100	103.50	63.60	78.60	88.60	88.60
Dow Jones US Oil & Gas Index	100	133.00	90.00	96.80	113.70	116.20
Peer Group	100	91.30	63.70	61.20	76.20	67.60

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

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Securities Authorized for Issuance Under Compensation Plans

The table below includes information about our equity compensation plans as of December 31, 2011, each of which has been approved by our stockholders:

	Number of Shares Authorized for Issuance under plan	Number of securities to be issued upon exercise of outstanding options and restricted stock	Weighted-average exercise price of outstanding options and restricted stock	Number of securities remaining available for future issuance under equity compensation plans
2000 Equity Incentive Plan	1,975,000	758,348	$ 6.94	—
2001 Stock Incentive Plan	2,500,000	912,221	$ 4.77	—
2001 Key Employee Stock Incentive Plan	2,500,000	1,257,416	$ 1.45	—
2010 Stock Incentive Plan	6,950,000	780,731	$ 4.10	6,164,202
Total	13,925,000	3,708,716	$ 3.95	6,164,202

Recent Sales of Unregistered Securities

There were no unregistered sales of equity securities in fiscal 2011.

Issuer Purchases of Equity Securities

The Company did not repurchase any of its equity securities in the fourth quarter of 2011.

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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, 2011, 2010, 2009, 2008 and 2007 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,				
	2011	2010	2009	2008	2007
	(in thousands, except share and per share data)				
Consolidated Statement of Operations Data:					
Revenues:					
Oil & gas sales	$ 103, 371	$ 88,275	$ 63,402	$ 108,032	$ 59,308
Costs and operating expenses:					
Lease operating expenses	30,637	28,845	27,097	31,062	22,924
Depreciation, depletion and amortization	30,517	21,993	20,617	23,977	11,393
Impairment expense	—	—	—	275,684	—
General and administrative	14,819	15,358	12,641	14,722	13,771
Total costs and operating expenses	75,973	66,196	60,355	345,445	48,088
Income (loss) from operations	27,398	22,079	3,047	(237,413)	11,220
Other income:					
Interest and other income	77	247	177	1,022	2,385
Interest expense	(3,188)	(3,500)	(5,910)	(5,293)	(2,170)
Gain (loss) on derivatives	(2,726)	1,528	(10,973)	—	—
Net gain (loss) on investment	—	—	3	98	(46)
Total other income (expense)	(5,837)	(1,725)	(16,703)	(4,173)	169
Income (loss) before income taxes	21,561	20,354	(13,656)	(241,586)	11,389
Income tax expense (benefit)	(78)	(29)	63	(29)	(16)
Net income (loss) before dividends and accretion	21,639	20,383	(13,719)	(241,557)	11,405
Preferred dividends and accretion	10	18	96	98	267
Net income (loss) applicable to common stockholders	$ 21,629	$ 20,365	$ (13,815)	$ (241,655)	$ 11,138
Earnings (loss) per share—Basic	$ 0.31	$ 0.29	$ (0.23)	$ (4.17)	$ 0.20
Earnings (loss) per share—Diluted	$ 0.30	$ 0.29	$ (0.23)	$ (4.17)	$ 0.20
Weighted average shares outstanding—Basic	70,830,855	70,382,517	60,492,900	58,000,166	55,892,536
Weighted average shares outstanding—Diluted	72,047,488	71,429,110	60,492,900	58,000,166	56,978,948
Consolidated Statement of Cash Flows Data:					
Net cash provided by (used in):					
Operating activities	$ 46,756	$ 45,321	$ 22,510	$ 62,014	$ 27,819
Investing activities	(64,176)	(29,082)	(40,722)	(111,446)	(104,561)
Financing activities	16,942	(22,385)	5,762	66,305	46,535

	As of December 31,				
	2011	2010	2009	2008	2007
Consolidated Balance Sheet Data:					
Cash and cash equivalents	$ 10,614	$ 11,092	$ 17,238	$ 29,688	$ 12,815
Total assets	323,633	272,596	260,419	286,633	440,506
Total long-term debt (including current maturities)	110,327	87,883	114,511	124,993	56,633
Stockholders' equity	174,091	150,674	128,758	112,025	349,529

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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 an independent energy company engaged in the exploration and development of domestic onshore oil and natural gas reserves. We focus our efforts primarily on our waterflood oil recovery programs and horizontal drilling in the Wilmington field within the Los Angeles Basin of California and on the exploration and development of coalbed methane ("CBM") properties located in the Rocky Mountain region. As of December 31, 2011, we owned natural gas and oil leasehold interests in approximately 129,588 gross (69,641 net) acres, approximately 80% 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 20% 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 contributed drilling locations, paid tangible drilling costs and provided turnkey drilling services. We also served as operator of these drilling programs and the Company retained an interest in the wells. Historically, a substantial portion of our revenue was attributable to these turnkey drilling services. After our initial public offering in 2004, the Company has transitioned from being the sponsor of privately placed drilling programs to becoming a more traditional exploration and production company. During the second quarter of 2007, the Company changed its accounting method for oil and gas properties from the successful efforts method to the full cost method. As a result of this accounting change, turnkey profit, well services profit and marketing profit are not recognized on the statement of operations but are recorded as reductions to the full cost pool. All historical information included in this Form 10-K has been retroactively restated to give effect to the change in accounting method.

Liquidity and Capital Resources

Our cash and cash equivalents decreased $0.5 million during 2011 to $10.6 million at December 31, 2011. This resulted from cash provided by operating activities of $46.8 million offset by cash used in investing activities of $64.2 million and cash provided by financing activities of $16.9 million.

Cash provided by operating activities was primarily generated by oil and gas operations. Cash used in investing activities was primarily spent on oil and gas properties and equipment. Cash provided by financing activities primarily represented an increase in net debt under the Credit Facility.

On December 15, 2011, the Company entered into a new, five-year $300 million Second Amended and Restated Credit Agreement with Bank of Montreal, as Administrative Agent (the "Agent"), and various other lenders named therein, and Warren Resources of California, Inc. and Warren E&P, Inc., as Guarantors (the "Credit Facility"). The Credit Facility provides for a revolving credit facility up to the lesser of: (i) $300 million, (ii) the Borrowing Base, or (iii) the Draw Limit requested by the Company. The Credit Facility matures on December 15, 2016, is secured by substantially all of Warren's oil and gas assets, and is guaranteed by the Guarantors, which are two wholly-owned subsidiaries of the Company. The initial Borrowing Base was increased to $130 million. The maximum amount available is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves in accordance with the lenders' customary procedures and practices. Both the Company and the lenders have the right to request one additional redetermination each year.

The Company is subject to various covenants required by the Credit Facility, including the maintenance of the following financial ratios: (1) a minimum current ratio of not less than 1.0 to 1.0 (including the unused borrowing base and excluding unrealized gains and losses on derivative financial instruments), and (2) a minimum annualized consolidated EBITDAX (as defined in the Credit Facility) to net interest expense of not less than 2.5 to 1.0.

Depending on the amount outstanding and the level of borrowing base usage, the annual interest rate on each base rate loan under the Credit Facility will be, at the Company's option, either: (a) a "LIBOR Loan", which has an interest rate equal to the sum of the applicable LIBOR period plus the applicable "LIBOR Margin" that ranges from 1.75% to 2.75%, or (b) a "Base Rate Loan", or any other obligation other than a LIBOR Loan, which has an interest rate equal to the sum of the "Base Rate", calculated to be 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 one-half percent, plus an applicable "Base Rate Margin" that ranges from 0.75% to 1.75%. As of December 31, 2011, the Company had borrowed $89.5 million under the Credit Facility and was in compliance with all covenants. If oil and gas commodity prices were to decline to lower levels, the Company may become in violation of Credit Facility covenants in the future. If the Company fails to satisfy its Credit Facility covenants, it would be an event of default. Under such event of default and upon notice, all borrowings would become immediately due and payable to the lending banks. During 2011, the Company incurred $2.7 million of interest expense under the Credit Facility of which approximately $0.1 million was accrued for as of December 31, 2011. The weighted average interest rate as of December 31, 2011, was 2.5%.

Our operations are affected by local, national and worldwide economic conditions. We have relied on the capital markets, particularly for equity securities, as well as the banking and debt markets, to meet financial commitments and liquidity needs if internally generated cash flow from operations is not adequate to fund our capital requirements. Capital markets in the United States and elsewhere have been experiencing extreme adverse volatility and disruption for more 3 years, due in part to the financial stresses affecting the liquidity of the banking system, the real estate mortgage industry and the financial markets generally. During the past 27 months, this volatility and disruption has been reduced. As a result, our access to capital has improved as evidenced by our $29 million equity offering during October 2009.

If oil commodity prices were to drop precipitously and gas commodity prices stay the same or go lower, the Company may not have enough liquidity to cover capital expenditures. The availability of funds under our Credit Facility is critical to our Company. The borrowing base is to be redetermined on or about April 1, 2012. If the Credit Facility's borrowing base is reduced to a level below current borrowings, the Company would be obligated to begin reducing the deficiency by 25% within 90 days after the deficiency occurs and the remaining 75% within 180 days after the deficiency occurs.

Low commodity prices may restrict our ability to meet our current obligations. As a result, Management has taken several actions to ensure that the Company will have sufficient liquidity to meet its obligations through December 31, 2012, including a 2012 capital expenditure budget which is expected to be funded primarily by discretionary cash flow, entered into put agreements and differential swap agreements for a portion of its 2012 production to reduce price volatility and reductions in discretionary expenditures. As of February 1, 2012, approximately 33% of the Company's oil production is covered by put agreements. If the liquidity of the Company should worsen, the Company would evaluate other measures to further improve its liquidity, including, the sale of equity or debt securities, entering into joint ventures with third parties, additional commodity price hedging and other monetization of assets strategies. There is no assurance that the Company would be successful in these capital raising efforts if they became necessary to fund operations during 2012.

During 2011, the Company had net income of $21.6 million (of which $2.7 million represented a loss on derivative financial instruments). This compares to 2010 when the Company had net income of $20.4 million (of which $1.5 million represented a gain on derivative financial instruments) and a net loss of $13.8 million in 2009 (of which $11.0 million represented a loss on derivative financial instruments). At December 31, 2011, current assets were approximately $16.3 million less than current liabilities. As of February 1, 2012, the Company has a borrowing base of $130 million and $89.5 million outstanding under the Credit Facility.

In the future, if natural gas inventories rise to levels such that no natural gas storage capacity exists, certain U.S. natural gas production will need to be reduced or shut in. Additionally, if commodity prices decline to levels that make it uneconomic to produce oil and natural gas, the Company or its partners may elect to shut in or reduce production. As a result, some or all of the Company's oil and natural gas production may be shut in or curtailed during the next 12 months, which would have a material adverse effect on operations.

The Company's proved reserves increased as of December 31, 2011 compared to prior years. The 2011 increase was primarily due to 2011 drilling activities and higher commodity prices. The Company's projects have material lease operating expenses. Our oil operations include a secondary recovery waterflood with significant fixed costs. During 2011, our oil lease operating expenses were $19.19 per barrel of oil produced. Our natural gas operations include reinjecting the produced water into deep formations and compressing and transporting the gas with significant fixed costs. During 2011, our natural gas lease operating expenses were $2.62 per mcf of gas produced. The Company's proved reserves are based on assumptions that may prove to be inaccurate. The Company's proved reserves as of December 31, 2009 through December 31, 2011 are listed below.

	Years Ended December 31,		
	2011	2010	2009
Estimated Proved Oil and Natural Gas Reserves:			
Net oil reserves (MBbls)	14,963	10,250	10,221
Net natural gas reserves (MMcf)	43,860	68,200	62,900
Total Net Proved Oil and Natural Gas Reserves (MBoe)	22,273	21,617	20,704
Estimated Present Value of Net Proved Reserves:			
PV-10 Value (in thousands)			
Proved developed	$ 359,549	$ 245,306	$ 191,450
Proved undeveloped	166,527	42,322	49,842
Total	526,076	287,628	241,292
Less: future income taxes, discounted at 10%	40,070	—	—
Standardized measure of discounted future net cash flows (in thousands)	$ 486,006	$ 287,628	$ 241,292
Prices Used in Calculating Reserves:			
Oil (per Bbl)	$ 104.75	$ 73.30	$ 54.33
Natural Gas (per Mcf)	$ 3.21	$ 4.13	$ 3.21
Proved Developed Reserves (MBoe)	13,101	15,735	16,244

2011 Capital Expenditure Program

At the present time, we are concentrating our activities in California and Wyoming. We have two California projects in the Wilmington field, the Wilmington Townlot Unit and the North Wilmington Unit. Additionally, we have a drilling project in Wyoming referred to as the Atlantic Rim Project.

During 2011, our capital expenditure program approximated $77.2 million. The Company drilled 18 wells in California (18 producers and no injectors). The costs associated with the new oil wells in California wells were approximately $46.0 million and the facility costs were approximately $12.4 million. In 2010, the Company purchased a sound-proofed drilling rig for our WTU and NWU units in California. During 2011, the Company incurred $7.0 million of assembly costs. The Company estimates that an additional $0.8 million will be spent on rig maintenance, improvements and assembly costs in 2012. Additionally, the Company drilled 25 gross (10 net) well in the Atlantic Rim Project in Wyoming. The costs associated with these new wells were $8.0 million. Additionally, infrastructure and other costs for the gas wells in Wyoming approximated $3.9 million.

If the Company elects not to participate in drilling activities with its partners, it may lose all or a portion of its mineral leases and rights in certain acreage. As a result, our proved reserves may decline. Also, unless we continue to develop our properties, production may decline and, as a result, reserves would decline. Lastly, complex federal, state and local laws and regulations may adversely affect the cost and feasibility of drilling and completion activities.

Our 2012 capital expenditure budget is forecasted to be approximately $79 million, $68 million for our California projects and $11 million for our Wyoming projects. However, our budget may change depending upon economic conditions, oil and gas prices and liquidity issues. In California, we are budgeting approximately $49 million for drilling new WTU directional wells and reworking existing WTU wells, $19 million for infrastructure and geological costs in the WTU and NWU. In Wyoming, we are budgeting $9 million for drilling new Atlantic Rim wells and $2 million for pipelines, compressors and infrastructure costs in our Atlantic Rim Project. The final determination regarding whether to drill and complete the budgeted wells and incur the capital expenditures referred to above is dependent upon many factors including, but not limited to:

- 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 crude oil and natural gas prices and the availability of drilling equipment.

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

See "Item 1A: Risk Factors" for additional risks and factors which could have a material adverse effect on our business, financial condition and results of operations.

Stock Based Equity Compensation Plan Information

At December 31, 2011, we had approximately 1.8 million vested outstanding stock options issued under our stock based equity compensation plans. Of the total 1.8 million outstanding vested options, 1.0 million had exercise prices below the closing market price of our common stock on December 31, 2011 of $3.26.

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 Schedule 14A.

Critical Accounting Estimates

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 account for our oil and gas activities using the full cost method. As prescribed by full cost accounting rules, all costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of oil and gas properties as well as other internal costs that can be specifically identified with acquisition, exploration and development activities are also capitalized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs are depleted on the equivalent unit-of-production method, based on proved oil and gas reserves as determined by independent petroleum engineers.

In accordance with full cost accounting rules, Warren is subject to a limitation on capitalized costs. The capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10 percent, plus the cost of unproved properties excluded from amortization, as adjusted for related tax effects. If capitalized costs exceed this limit (the "ceiling limitation"), the excess must be charged to expense. There was no impairment charge in 2011, 2010 and 2009.

The costs of certain unevaluated oil and gas properties and exploratory wells being drilled are not included in the costs subject to amortization. Warren assesses costs not being amortized for possible impairments or reductions in value and if impairments or a reduction in value has occurred, the portion of the carrying cost in excess of the current value is transferred to costs subject to amortization.

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

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. Warren accrues for revenue based on estimated pricing and production.

Recent Accounting Pronouncements

In June 2011, guidance was issued that (i) will require an entity to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements and (ii) eliminates the option to present the components of other comprehensive income as part of the statement of equity. This guidance will become effective on January 1, 2012, can be adopted early, and is not expected to have a material impact on the Company's consolidated financial statements.

In May 2011, the FASB issued ASU No. 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," to develop common requirements for valuation and disclosure of fair value measurements in accordance with U.S. GAAP and International Financial Reporting Standards. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities," to improve reporting and transparency of offsetting (netting) assets and liabilities and the related affects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

Results of Operations

Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010

Oil and gas sales. Revenue from oil and gas sales increased $15.1 million during 2011 to $103.4 million, a 17% increase compared to 2010. This increase primarily resulted from an increase in realized oil prices. Net oil production for 2011 and 2010 was 906 Mbbls and 969 Mbbls, respectively. Net gas production for 2011 and 2010 was 5.0 Bcf and 4.7 Bcf, respectively. Additionally, the average realized price per barrel of oil for 2011 and 2010 was $91.53 and $71.47, respectively. The average realized price per Mcf of gas for 2011 and 2010 was $3.98 and $4.09, respectively.

Lease operating expense. Lease operating expense for 2011 increased 6% to $30.6 million ($17.53 per Boe) compared to $28.8 million ($16.54 per Boe) in 2010. Oil lease operating expense increased on a per barrel basis from $17.29 in 2010 to $19.19 per barrel in 2011. This resulted from higher ad valorem taxes and costs associated with oil wells that were plugged and abandoned during 2011. Gas lease operating expense increased on a per mcf basis from $2.60 in 2010 to $2.62 per mcf in 2011. This resulted from increases in transportation costs offset by reductions in plugging and abandonment expense.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased $8.5 million in 2011 to $30.5 million, a 39% increase compared to last year. The 2011 depletion rate increased to $17.46 per boe compared to $12.61 per boe in 2010. The increase in the 2011 depletion rate compared to the 2010 depletion rate on a boe basis reflects an increase in estimated future development costs. Estimated future development costs were $188.7 million at December 31, 2011 compared to $84.6 million at December 31, 2010. Additionally during 2011, the Company recorded depreciation of $0.8 million related to its newly purchased drilling rig.

General and administrative expenses. General and administrative expenses decreased $0.5 million in 2011 to $14.8 million, a 4% decrease compared to 2010. This reflects a decrease in stock option expense, employer portion of taxes relating to vesting stock and legal expense of $0.9 million, $0.5 million and $0.5 million, respectively. This was offset by an increase in salaries and incentive compensation expense of $0.8 million and other miscellaneous items.

Interest expense. Interest expense decreased $0.3 million in 2011 to $3.2 million compared to 2010. The decrease results from lower interest rates related to our Credit Facility in 2011 compared to 2010.

Interest and other income. Interest and other income decreased $0.2 million in 2011 to $0.1 million, a 68% decrease compared to the same period in 2010. This decrease represents a decrease in the sale of scrap inventory during 2011.

Gain (loss) on derivative financial instruments. Derivative losses of $2.7 million were recorded in 2011. This amount reflects $12.2 million of realized losses and $9.5 million of unrealized gains resulting from mark to market accounting of our oil and gas derivative positions. Derivative gains of $1.5 million were recorded in 2010. This amount reflects $2.7 million of realized gains and $1.2 million of unrealized losses resulting from mark to market accounting of our oil and gas swaps positions.

Income taxes. We recognize 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 and tangible drilling costs and unrealized gains on investments.

As of December 31, 2011, we had a net operating loss carryforward for federal income tax purposes of approximately $248 million. Also as of December 31, 2011, we have provided a 100% valuation allowance on our net deferred tax assets. Our net operating loss carryforwards begin to expire in 2012 and subsequent years.

Results of Operations

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Oil and gas sales. Revenue from oil and gas sales increased $24.9 million during 2010 to $88.3 million, a 39% increase compared to 2009. This increase primarily resulted from an increase in oil production and an increase in realized oil prices. Net oil production for 2010 and 2009 was 969 Mbbls and 953 Mbbls, respectively. Net gas production for 2010 and 2009 was 4.7 Bcf and 3.9 Bcf, respectively. Additionally, the average realized price per barrel of oil for 2010 and 2009 was $71.47 and $53.93, respectively. The average realized price per Mcf of gas for 2010 and 2009 was $4.09 and $3.09, respectively.

Lease operating expense. Lease operating expense for 2010 increased 6% to $28.8 million ($16.54 per Boe) compared to $27.1 million ($16.93 per Boe) in 2009. Oil lease operating expense increased on a per barrel basis from $16.22 in 2009 to $17.29 per barrel in 2010. This resulted from higher costs associated with oil wells that were plugged and abandoned during 2010. Gas lease operating expense decreased on a per mcf basis from $3.00 in 2009 to $2.60 per mcf in 2010. This resulted from a reduction in the number of gas wells that required workover procedures during 2010.

Depreciation, depletion and amortization. Depreciation, depletion and amortization expense increased $1.4 million for 2010 to $22 million, a 7% increase compared to last year. This increase resulted from increased production in 2010 compared to 2009. The 2010 depletion rate decreased to $12.61 per Boe compared to $12.88 per Boe in 2009. The decrease in depreciation, depletion and amortization on a per barrel basis resulted from an increase in proved reserves at December 31, 2010 compared to December 31, 2009.

General and administrative expenses. General and administrative expenses increased $2.7 million in 2010 to $15.4 million, a 21% increase compared to 2009. This reflects an increase in the 2010 year end incentive compensation plan of $2.6 million. Additionally, the employer portion of taxes relating to vesting stock increased $0.6 million and stock option expense increased $0.5 million during 2010. These increases were offset by a decrease in litigation expense of $1.3 million during 2010 primarily relating to the Gotham litigation discussed in more detail in Note F to the financial statements—Commitment and Contingencies.

Interest expense. Interest expense decreased $2.4 million in 2010 to $3.5 million compared to 2009. The decrease results from a lower average balance outstanding under our Credit Facility during 2010 compared to 2009.

Interest and other income. Interest and other income increased $0.1 million in 2010 to $0.2 million, a 39% increase compared to the same period in 2009. This increase represents an increase in the sale of scrap inventory during 2010.

Gain (loss) on derivative financial instruments. Derivative gains of $1.5 million were recorded in 2010. This amount reflects $2.7 million of realized gains and $1.2 million of unrealized losses resulting from mark to market accounting of our oil and gas derivative positions. Derivative losses of $11.0 million were recorded in 2009. This amount reflects $1.5 million of realized losses and $9.5 million of unrealized losses resulting from mark to market accounting of our oil and gas swaps positions.

Income taxes. We recognize 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 and tangible drilling costs and unrealized gains on investments.

As of December 31, 2010, we had a net operating loss carryforward for federal income tax purposes of approximately $220 million. Also as of December 31, 2010, we have provided a 100% valuation allowance on our net deferred tax assets. Our net operating loss carryforwards begin to expire in 2012 and subsequent years.

Debentures

As of December 31, 2011, we had outstanding $1.7 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 fair market value of these securities at December 31, 2011 was approximately $1.3 million.

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 2012. The conversion prices listed below will increase in the future.

Debentures	Outstanding at December 31, 2011	Conversion Price as of December 31, 2011	Fair Market Value of U.S. Treasuries	Estimated Debenture Interest for 2012
	(in thousands, except conversion price data)			
12% Convertible secured Debentures due December 31, 2020	$ 850	$ 35.00	$ 721	$ 102
12% Convertible secured Debentures due December 31, 2022	801	$ 35.00	628	96
	$ 1,651		$ 1,349	$ 198

Preferred Stock

As of December 31, 2011, we had 10,703 shares of convertible preferred stock issued and outstanding. During 2011, no shares of our convertible preferred stock converted into common shares. The preferred stock is convertible into common shares on a 1 to 0.5 basis. Dividends and accretion on preferred shares totaled approximately $10,000 and $18,000 for the years ended December 31, 2011 and 2010, 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, 2011, there were 10,703 preferred shares outstanding that the Company may be required to redeem.

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 10,703 shares of preferred stock representing $0.1 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 10,703 shares of our shares of common stock, nor be obligated to issue more than 16,055 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 outstanding shares of our preferred stock request redemption 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 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

A summary of our contractual obligations as of December 31, 2011 is provided in the following table. The below table assumes the maximum amount of bonds are tendered each year. The table does not give effect to the conversion of any bonds to common stock which would reduce payments due. All bonds are secured at maturity by zero coupon U.S. treasury bonds deposited into an escrow account equaling the par value of the bonds maturing on or before the maturity of the bonds. Such U.S.

treasury bonds had a fair market value of approximately $1.3 million at December 31, 2011. The table below does not reflect the release of escrowed U.S. treasury bonds to us upon redemption.

Contractual Obligations As of December 31, 2011	Payments due by period* Total	Less Than 1 Year	1 - 3 Years	3 - 5 Years	More Than 5 Years
	(in thousands)				
Line of credit	$ 89,500	$ —	$ —	$ 89,500	$ —
Bonds	1,651	165	282	229	975
Leases	1,472	599	804	69	—
Drilling rig obligation	717	717	—	—	—
Other Notes Payable	107	107	—	—	—
Total	$ 93,447	$ 1,588	$ 1,086	$ 89,798	$ 975

* Does not include estimated interest of $2.7 million less than one year, $5.4 million 1-3 years, $5.3 million 3-5 years and $1.0 million thereafter.

Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements.

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Risk

Our primary market risk exposure is in the price we receive for our natural gas and oil production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot regional market prices applicable to our U.S. natural gas production. Pricing for natural gas and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

We have entered into several commodity derivative contracts to hedge our exposure to commodity price risk associated with anticipated future oil and gas production. We believe we will have more predictability of our crude oil and gas revenues as a result of these derivative contracts.

The following table summarizes our open financial derivative positions as of March 2, 2012 related to oil and gas production.

Product	Type	Contract Period	Volume	Price per Mcf or Bbl
BRENT Oil	Put	04/01/12 - 12/31/12	1,818 Bbl/d	$ 90
NYMEX Oil	Put	01/01/12 - 12/31/12	1,000 Bbl/d	$ 70
Natural Gas Differential	Swap	01/01/12 - 12/31/12	3,000 Mcf/d	$ (0.51)*

* This represents a differential spread between NYMEX Natural Gas and CIG pricing.

For put options, we typically pay a premium to the counterparty in exchange for the sale of the instrument. If the index price is below the floor price of the put option, we receive the difference between the floor price and the index price multiplied by the contract volumes less the option premium. If the index price settles at or above the floor price of the put option, we pay only the option premium.

Under a swap contract, the counterparty is required to make a payment to us if the index price for any settlement period is less than the fixed price, and we are required to make a payment to the counterparty if the index price for any settlement period is greater than the fixed price.

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. Occasionally, 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.

At December 31, 2011, we had debt outstanding under our Credit Facility of $89.5 million. 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) a "LIBOR Loan", which has an interest rate equal to the sum of the applicable LIBOR period plus the applicable "LIBOR Margin" that ranges from 1.75% to 2.75%, or (b) a "Base Rate Loan", or any other obligation other than a LIBOR Loan, which has an interest rate equal to the sum of the "Base Rate", calculated to be 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 one-half percent, plus an applicable "Base Rate Margin" that ranges from 0.75% to 1.75%. During 2011, the Company incurred $2.7 million of interest under the Credit Facility of which approximately $0.1 million of interest was accrued for at December 31, 2011. At December 31, 2011, the weighted average interest rate on our Credit Line was 2.5%. A 1% increase in this rate would result in annual additional interest of $0.9 million.

Financial Instruments

Our financial instruments consist of cash and cash equivalents, U.S. treasury bonds, collateral security accounts, derivatives and other long-term liabilities. The carrying amounts of cash and cash equivalents and U.S. treasury bonds approximate fair market value due to the highly liquid nature of these short-term instruments or they are reported at fair value. Debentures, derivatives, other long-term liabilities and the Credit Line are recorded at the approximate fair value of such items.

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, 2011 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.

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, 2011, 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 and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of our assets;

- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

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, 2011 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, 2011.

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 the effectiveness of the Company's internal control over financial reporting as of December 31, 2011.

Changes in Internal Control over Financial Reporting.

There were no changes in internal control over financial reporting that occurred during the most recent fiscal 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, 2012 (to be filed with the SEC within 120 days after the end of the Company's fiscal year ended December 31, 2011) 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 herein.

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.

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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 herein.

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 "Regulations and Environmental Matters" and "—Future Regulations" herein.

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(11)	Articles of Incorporation of Registrant filed May 20, 2004 (Maryland)
3.2(8)	Bylaws of the Registrant, dated June 2, 2004
3.3(8)	Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($. 0001 Par Value) (Maryland)
3.4(8)	Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland)
3.5(8)	Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($. 0001 Par Value) (Maryland)
3.6(8)	Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland)
4.1(11)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(6)	Form of Class A Common Stock Warrant
4.3(6)	Form of Class B Common Stock Warrant
4.4(2)	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(4)	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

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Exhibit No.	Description
4.6(8)	Form of Subscription and Registration Rights Agreement dated July 30, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated July 9, 2004
4.7(17)	Rights Agreement, dated as of August 29, 2008
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(7)*	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Norman F. Swanton
10.8(13)*	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Norman F. Swanton
10.9(7)*	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin
10.10(13)*	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Timothy A. Larkin
10.11(13)*	Employment Agreement dated as of July 1, 2005, between the Registrant and Lloyd Davies
10.12(13)*	Employment Agreement executed on June 17, 2005, between the Registrant and David E. Fleming
10.13(8)*	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(3)	Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc.
10.17(3)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.18(3)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.
10.19(9)	Purchase and Sale Agreement dated November 24, 2004 by and among Warren Resources of California, Inc., Magness Petroleum Company and Next Generation Investments, LLC.

Exhibit No.	Description
10.20(9)	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(12)	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
10.22(14)	Form of Asset Purchase Agreement
10.23(15)	First Amendment to Credit Agreement dated as of August 9, 2007 amount Warren Resources, Inc., the lenders party thereto and JP Morgan Chase Bank, N.A.
10.24(16)	Amended and Restated Credit Agreement dated as of November 19, 2007 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Merrill Lynch Capital, a Division of Merrill Lynch Business Financial Services Inc., as Administrative Agent, as a Lender and as Sole Bookrunner and Sole Lead Arranger, and the additional Lenders party thereto
10.25(18)	General Release and Severance Agreement with Lloyd G. Davies dated effective as of January 1, 2009
10.26(19)	Form of Change in Control Agreement, dated as of May 9, 2009, between Warren Resources, Inc. and certain employees of Warren Resources, Inc.
10.27(20)	First Amendment to Amended and Restated Credit Agreement dated as of May 12, 2009 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Merrill Lynch Capital, a Division of Merrill Lynch Business Financial Services Inc., as Administrative Agent, as a Lender and as Sole Bookrunner and Sole Lead Arranger, and the additional Lenders party thereto
10.28(21)*	2010 Stock Incentive Plan
10.29(22)	Second Amended and Restated Credit Agreement dated as of December 15, 2011 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Bank of Montreal, as Administrative Agent, as a Lender and the additional Lenders party thereto.
10.30(23)	Coalbed Natural Gas (CBNG) Unit Agreement for the Development and Operation of the Spyglass Hill (CBNG) Unit area. Count of Carbon, State of Wyoming, dated February 26, 2011, by and between the parties identified therein
10.31(23)	Unit Operating Agreement Spyglass Hill (CBNG) Unit Area, dated February 26, 2011, by and among the parties identified therein.
11(24)	Statements regarding Computation of Per Share Earnings (Included in the Financial Statement in Part 4)
14(5)	Code of Ethics for Senior Financial Officers
21.1(10)	Subsidiaries of the Registrant
23.1(24)	Consent of Williamson Petroleum Consultants, Inc., Independent Petroleum Engineer
23.2(24)	Consent of Grant Thornton LLP
23.3(24)	Consent of Netherland, Sewell & Associates, Inc.

Exhibit No.	Description
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
99.1(23)	Report of Williamson Petroleum Consultants, Inc., Independent Petroleum Engineer
99.2(24)	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineer
101(24)	The following materials from the Warren Resources, Inc. Annual Report on Form 10-K for the year ended December 31, 2011 (and related periods), formatted in XBRL (eXtensible Business Reporting Language) include (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Stockholders' Equity and Comprehensive Income, (iv) the Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements.

* Denotes a management contract or compensatory plan or arrangement.

** Users of this data are advised pursuant to Rule 401 of Regulations S-T that the financial information contained in the XBRL-Related Documents is unaudited. Furthermore, users of this data are advised in accordance with Rule 406T of Regulations S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these Sections.

(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 Current Report on Form 8-K, Commission File No. 000-33275, filed on December 17, 2002.

(3) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 24, 2002.

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

(5) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2002, Commission File No. 000-33275, filed on March 31, 2003.

(6) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, Commission File No. 000-33275, filed on March 15, 2004.

(7) Incorporated by reference to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, Commission File No. 000-33275, filed May12, 2004.

(8) Incorporated by reference to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, Commission File No. 000-33275, filed on August 13, 2003.

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

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

(11) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 000-33275, filed on March 17, 2005.

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

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

(14) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed June 22, 2007.

(15) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 21, 2007.

(16) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed November 20, 2007.

(17) Incorporated by reference to the Company's Form 8-A filed on September 5, 2008, Commission File No. 001-34169.

(18) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed January 7, 2009.

(19) Incorporated by reference to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed August 5, 2009.

(20) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed May 15, 2009.

(21) Incorporated by reference to the Company's Definitive Proxy Statement on Form DEF 14-A filed on April 8, 2010.

(22) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 16, 2011.

(23) Incorporated by reference to the Company's Annual Report on Form 10-K/A, Commission File No. 000-33275, filed October 27, 2011.

(24) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, Commission File No. 000-33275, filed March 6, 2012.

† Filed herewith.

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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: April 5, 2012

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INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders
Warren Resources, Inc.

We have audited Warren Resources, Inc. (a Maryland Corporation) and subsidiaries (collectively, the "Company") internal control over financial reporting as of December 31, 2011, 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, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We also have 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, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2011 and our report dated March 6, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 6, 2012

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. (a Maryland Corporation) and subsidiaries (collectively, the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, stockholders' equity and comprehensive income and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note A, the Company changed its method of estimating oil and gas reserves and related disclosures in 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated March 6, 2012 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
March 6, 2012

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Warren Resources, Inc. and Subsidiaries

CONSOLIDATED BALANCE SHEETS

December 31,

	2011	2010
	(in thousands, except share and per share data)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 10,614	$ 11,092
Accounts receivable—trade, net	13,660	12,512
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $89 in 2011 and $84 in 2010)	135	110
Derivative financial instruments	309	—
Other current assets	948	1,040
Total current assets	25,666	24,754
Other Assets		
Oil and gas properties—at cost, based on full cost method of accounting, net of accumulated depreciation, depletion and amortization (includes unproved properties excluded from amortization of $22,963 and $25,732 as of December 31, 2011 and 2010)	275,443	231,746
Property and equipment—at cost, net	16,926	10,817
Restricted investments in U.S. Treasury bonds—available for sale, at fair value (amortized cost of $804 in 2011 and $756 in 2010)	1,214	987
Derivative financial instruments	—	392
Other assets	4,383	3,900
Total other assets	297,966	247,842
	$ 323,632	$ 272,596
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Current maturities of debentures and other long-term liabilities	$ 2,831	$ 3,631
Accounts payable and accrued expenses	38,234	24,414
Derivative financial instruments	980	9,625
Total current liabilities	42,045	37,670
Long-Term Liabilities		
Debentures, less current portion	1,486	1,486
Other long-term liabilities, less current portion	16,510	12,663
Derivative financial instruments	—	603
Line of credit	89,500	69,500
	107,496	84,252
Commitments and contingencies (Note F)		
Stockholders' Equity		
8% convertible preferred stock—$.0001 par value; authorized, 10,000,000 shares; issued and outstanding, 10,703 shares in 2011 and 2010 respectively (aggregate liquidation preference $128 in 2011 and 2010)	128	128
Common stock—$.0001 par value; authorized, 100,000,000 shares; issued, 71,518,810 shares in 2011 and 71,338,149 shares in 2010	7	7
Additional paid-in capital	464,985	463,326
Accumulated deficit	(290,578)	(312,217)
Accumulated other comprehensive income, net of applicable income taxes of $181 in 2011 and $103 in 2010	277	158
	174,819	151,402
Less common stock in Treasury—at cost; 632,250 shares in 2011 and 2010	728	728
Total Stockholders' Equity	174,091	150,674
	$ 323,632	$ 272,596

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31,

	2011	2010	2009
	(in thousands, except share and per share amounts)		
Operating Revenues			
Oil and gas sales	$ 103,371	$ 88,275	$ 63,402
Operating Expenses			
Lease operating expenses	30,637	28,845	27,097
Depreciation, depletion and amortization	30,517	21,993	20,617
General and administrative	14,819	15,358	12,641
Total operating expenses	75,973	66,196	60,355
Income (loss) from operations	27,398	22,079	3,047
Other income (expense)			
Interest and other income	77	247	177
Interest expense	(3,188)	(3,500)	(5,910)
Gain (loss) on derivative financial instruments	(2,726)	1,528	(10,973)
Net gain on investments	—	—	3
Net other expense	(5,837)	(1,725)	(16,703)
Income (loss) before provision for income taxes	21,561	20,354	(13,656)
Deferred income tax expense (benefit)	(78)	(29)	63
Net income (loss)	21,639	20,383	(13,719)
Less dividends and accretion on preferred shares	10	18	96
Net income (loss) applicable to common stockholders	$ 21,629	$ 20,365	$ (13,815)
Basic and diluted income (loss) per common share—Basic	$ 0.31	$ 0.29	$ (0.23)
Basic and diluted income (loss) per common share—Diluted	$ 0.30	$ 0.29	$ (0.23)
Weighted average common shares outstanding—Basic	70,830,855	70,382,517	60,492,900
Weighted average common shares outstanding—Diluted	72,047,488	71,429,110	60,492,900

The accompanying notes are an integral part of these statements.

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Warren Resources, Inc. and Subsidiaries
CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
Years ended December 31, 2011, 2010 and 2009

	Preferred stock		Common stock		Additional paid-in capital	Accumulated deficit	Accumulated other comprehensive income	Treasury stock	Total Stockholders' equity
	Shares	Amount	Shares	Amount					
					(in thousands)				
Balance at January 1, 2009	98	$ 1,177	58,826	$ 6	$430,243	$ (318,881)	$ 208	$ (728)	$ 112,025
Issuance of common stock, net of offering costs	—	—	11,775	1	28,720	—	—	—	28,721
Shares issued from vesting of restricted stock	—	—	50	—	—	—	—	—	—
Dividends declared on preferred stock	—	—	—	—	(94)	—	—	—	(94)
Stock based compensation	—	—	—	—	1,920	—	—	—	1,920
Accretion of preferred stock to redemption value	—	2	—	—	(2)	—	—	—	—
Net loss	—	—	—	—	—	(13,719)	—	—	(13,719)
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	(95)	—	(95)
Total comprehensive loss									(13,814)
Balance at December 31, 2009	98	$ 1,179	70,651	$ 7	$460,787	$ (332,600)	$ 113	$ (728)	$ 128,758
Shares issued from exercise of options	—	—	250	—	128	—	—	—	128
Shares issued from vesting of restricted stock	—	—	437	—	—	—	—	—	—
Repurchase of preferred stock	(87)	(1,051)	—	—	—	—	—	—	(1,051)
Dividends declared on preferred stock	—	—	—	—	(18)	—	—	—	(18)
Stock based compensation	—	—	—	—	2,429	—	—	—	2,429
Net income	—	—	—	—	—	20,383	—	—	20,383
Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	45	—	45
Total comprehensive income									20,428
Balance at December 31, 2010	11	$ 128	71,338	$ 7	$463,326	$ (312,217)	$ 158	$ (728)	$ 150,674
Shares issued from exercise of options	—	—	156	—	123	—	—	—	123
Shares issued from vesting of restricted stock	—	—	25	—	—	—	—	—	—
Dividends declared on preferred stock	—	—	—	—	(10)	—	—	—	(10)
Stock based compensation	—	—	—	—	1,546	—	—	—	1,546
Net income	—	—	—	—	—	21,639	—	—	21,639

Net change in unrealized gain on investment securities available for sale, net of applicable income taxes	—	—	—	—	—	—	119	—	119
Total comprehensive income									21,758
Balance at December 31, 2011	11	$ 128	71,519	$ 7	$464,985	$ (290,578)	$ 277	$ (728)	$ 174,091

The accompanying notes are an integral part of these statements.

Warren Resources, Inc. and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,

	2011	2010	2009
	(in thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 21,639	$ 20,383	$ (13,719)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Accretion of discount on available for sale debt securities	(54)	(51)	(49)
Amortization and write-off of deferred debt offering costs	478	199	213
Gain on sale of U.S. Treasury bonds—available for sale	—	—	(3)
Depreciation, depletion, amortization and impairment	30,517	21,993	20,617
Deferred tax expense (benefit)	(78)	(29)	63
Loss (gain) on derivative financial instruments	(9,165)	(540)	10,377
Stock option expense	1,546	2,429	1,920
Change in assets and liabilities:			
Increase in accounts receivable—trade	(879)	(1,121)	(1,160)
Decrease (increase) in other assets	71	(443)	130
Increase in accounts payable and accruals	3,646	3,221	2,844
Increase (decrease) in other long term liabilities	(965)	(720)	1,277
Net cash provided by operating activities	46,756	45,321	22,510
Cash flows from investing activities:			
Purchase, exploration and development of oil and gas properties	(56,598)	(23,380)	(40,695)
Purchases of property and equipment	(7,578)	(5,702)	(43)
Proceeds from U.S. Treasury bonds—available for sale	—	—	16
Net cash used in investing activities	(64,176)	(29,082)	(40,722)
Cash flows from financing activities:			
Proceeds from line of credit	98,657	—	7,032
Payments on long-term debt	(81,838)	(21,462)	(29,991)
Issuance of common stock, net	123	128	28,721
Repurchase of preferred stock, net	—	(1,051)	—
Net cash provided by (used in) financing activities	16,942	(22,385)	5,762
Net decrease in cash and cash equivalents	(478)	(6,146)	(12,450)
Cash and cash equivalents at beginning of year	11,092	17,238	29,688
Cash and cash equivalents at end of year	$ 10,614	$ 11,092	$ 17,238
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 2,699	$ 3,269	$ 6,210
Noncash investing and financing activities:			
Accrued preferred stock dividend	$ 10	$ 18	$ 337
Change in accounts payable relating to oil and gas property	10,630	3,518	(35,405)
Note payable on purchase of property and equipment	—	3,500	—
Increase (decrease) in asset retirement liability	5,260	1,428	158

The accompanying notes are an integral part of these statements.

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Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2011, 2010 and 2009

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 California, Wyoming, New Mexico, North Dakota and Texas.

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. All significant intercompany accounts and transactions have been eliminated in consolidation.

Oil and Gas Properties

The Company accounts for its oil and gas activities using the full cost method. As prescribed by full cost accounting rules, all costs associated with property acquisition, exploration and development activities are capitalized. Exploration and development costs include dry hole costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil and gas reserves. Salaries and benefits paid to employees directly involved in the exploration and development of oil and gas properties as well as other internal costs that can be specifically identified with acquisition, exploration and development activities are also capitalized. Proceeds received from disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs are depleted on the equivalent unit-of-production method, based on proved oil and gas reserves as determined by independent petroleum engineers.

In accordance with full cost accounting rules, the Company is subject to a limitation on capitalized costs. The capitalized cost of oil and gas properties, net of accumulated depreciation, depletion and amortization, may not exceed the estimated future net cash flows from proved oil and gas reserves discounted at 10 percent, plus the cost of unproved properties excluded from amortization, as adjusted for related tax effects. If capitalized costs exceed this limit (the "ceiling limitation"), the excess must be charged to expense. There was no impairment charge in 2011, 2010 or 2009.

The costs of certain unevaluated oil and gas properties and exploratory wells being drilled are not included in the costs subject to amortization. The Company assesses costs not being amortized for possible impairments or reductions in value and if impairments or a reduction in value has occurred, the portion of the carrying cost in excess of the current value is transferred to costs subject to amortization.

Revenue Recognition

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. For 2011, the largest purchasers and marketers for the Company's production primarily

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

included ConocoPhillips and Anadarko Energy Services, which accounted for 52% and 38%, respectively, of total oil and natural gas sold in 2011. For 2010, the largest purchasers and marketers for the Company's production primarily included ConocoPhillips and Anadarko Energy Services, which accounted for 55% and 33%, respectively, of total oil and natural gas sold in 2010. For 2009, the largest purchasers and marketers for the Company's production primarily included ConocoPhillips and Anadarko Energy Services, which accounted for 59% and 28%, respectively, of total oil and natural gas sold in 2009.

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 may exceed federally insured limits. At December 31, 2011, the Company had the majority of its cash and cash equivalents with one financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on cash and cash equivalents.

Accounts Receivable

Accounts receivable include 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. As of December 31, 2011 and 2010, the Company has an allowance of $13,000 and $125,000 for doubtful accounts, respectively.

Investments

The Company classifies its investment in 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). Available-for-sale securities represent the market value of zero coupon Treasury Bonds collateralizing convertible debentures and are classified as current or non-current based on the classification of the related debentures. Realized gains and losses are determined on the basis of specific identification of the securities.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

Offering Costs

Costs incurred in connection with the issuance of debt are capitalized and amortized over the term of the related debt using the effective interest rate method. The Company has $1.5 million and $1.5 million, net of accumulated amortization of $377 thousand and $879 thousand, included in other assets at December 31, 2011 and 2010, respectively. 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. The Company's policy is to classify accrued penalties and interest related to unrecognized tax benefits in the Company's income tax provision. The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. Only tax positions that meet the more-likely-than-not recognition threshold are recorded.

Use of Estimates

In preparing financial statements, accounting principles generally accepted in the United States of America require management to make estimates and assumptions in determining the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In addition, significant estimates are used in determining year end proved oil and gas reserves. Actual results could differ from those estimates. The estimate of the Company's oil and natural gas reserves, which is used to compute depreciation, depletion, amortization and impairment of oil and gas properties, is the most significant of the estimates and assumptions that affect reported results.

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.

Stock Based Compensation

The Company uses the Black-Scholes option-pricing formula to estimate the fair value of stock based compensation expense at the grant date related to stock options issued. This expense is then recognized using the straight-line method over the vesting period. For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $1.5 million, $2.4 million and $1.9 million in compensation expense, respectively, related to stock option plans and restricted stock.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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 2011, 2010 and 2009, respectively: No expected dividends, weighted average volatility of 75%, 78%, and 70%, risk-free interest rates of 1.26%, 1.60%, and 1.54% and expected lives of 3.5 years for incentive options issued in 2011, 2010 and 2009. The volatility assumptions were calculated based on the performance of our stock prices for the year. The weighted average fair values of the options issued in 2011, 2010 and 2009 were $2.04, $1.33, and $0.28, respectively.

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.

Derivative financial instruments

The Company has entered into several crude oil and natural gas hedges in order to minimize any effect of a downturn in oil and gas prices and protect profitability. These derivative financial instruments are carried on the balance sheet at fair value. If a derivative is designated as a fair value hedge, the changes in the fair value of the derivative and of the hedged item attributable to the hedged risk are recognized in earnings. If a derivative is designated as a cash flow hedge, the effective portions of changes in the fair value of the derivative are recorded in other comprehensive income ("OCI") and are recognized in the statement of operations when the hedged item affects earnings. Ineffective portions of changes in the fair value of cash flow hedges are recognized in earnings. The Company has elected not to designate its derivatives as fair value or cash flow hedges (Note I). Gains and losses resulting from changes in the fair value of the non-designated hedges are recognized in earnings.

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 25 years, except for land which is not depreciated. Property and equipment consisted of the following at December 31:

	2011	2010
	(in thousands)	
Drilling rig	$ 16,627	$ 9,616
Equipment	1,543	1,543
Automobiles and trucks	662	654
Furniture and fixtures	422	418
Land and buildings	872	872
Office equipment	1,424	1,361
	21,550	14,464
Less accumulated depreciation and amortization	4,624	3,647
	$ 16,926	$ 10,817

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

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 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, 2011, diluted weighted average common shares outstanding includes in the money employee stock options of 1,216,633.

	Year ended December 31,		
	2011	2010	2009
Weighted average shares outstanding—basic	70,830,855	70,382,517	60,492,900
Incremental shares issuable from dilutive stock options	1,216,633	1,046,593	—
Weighted average shares outstanding—diluted	72,047,488	71,429,110	60,492,900

Potential common shares relating to options, warrants, preferred stock, restricted 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,		
	2011	2010	2009
Employee stock options	918,416	2,208,666	3,419,040
Convertible debentures	47,170	47,170	47,170
Preferred stock	5,352	5,352	49,056
Warrants	—	—	52,038
Restricted Stock	615,731	28,373	81,113

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).

At December 31, 2011, 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).

Asset Retirement Obligations

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. The associated liability is classified in other

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

long-term liabilities, net of current portion, 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 and amortization. The Company has cash held in escrow with a fair market value of $3.2 million that is legally restricted for potential plugging and abandonment liability in the Wilmington field which is recorded in other assets in the Consolidated Balance Sheets. A reconciliation of the Company's asset retirement obligations is as follows:

	December 31,	
	2011	2010
	(in thousands)	
Balance at beginning of year	$ 10,217	$ 8,689
Liabilities incurred in current year	113	106
Liabilities settled in current year	(965)	(720)
Accretion expense	995	820
Revisions in estimated cash flows	5,147	1,322
Carrying amount	$ 15,507	$ 10,217

Recently Issued Accounting Pronouncements

On December 31, 2008, the SEC published a final rule to revise its oil and gas reserves estimation and disclosure requirements. The primary objectives of the revisions were to increase the transparency and information value of reserve disclosures and improve comparability among oil and gas companies. The rule was effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009. The revised rules amended the definition of proved reserves to permit consideration of new technologies in evaluating oil and natural gas reserves; require the use of an average price based on the prior twelve month period rather than year-end prices, permit the disclosure of probable and possible oil and gas reserves, and revised other oil and natural gas disclosure requirements for operations. The adoption of these rules resulted in lower prices being used for both oil and gas in the preparation of the 2009 reserve report and a decrease in 2009 reserves of approximately 11.2 Bcfe. Additionally, the decrease in reserves resulted in additional depletion, depreciation and amortization being recorded in the fourth quarter of approximately $0.4 million. In January 2010, the FASB issued guidance in the "Extractive Activities—Oil and Gas" topic of the FASC that aligns the FASB's oil and gas reserve estimation and disclosure requirements with the new SEC rule revisions. The new guidance was effective for the Company for the year ending December 31, 2009.

In June 2011, guidance was issued that (i) will require an entity to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements and (ii) eliminates the option to present the components of other comprehensive income as part of the statement of equity. This guidance will become effective on January 1, 2012, can be adopted early, and is not expected to have a material impact on the Company's consolidated financial statements.

NOTE A—ORGANIZATION AND ACCOUNTING POLICIES (Continued)

In May 2011, the FASB issued ASU No. 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," to develop common requirements for valuation and disclosure of fair value measurements in accordance with U.S. GAAP and International Financial Reporting Standards. This ASU is effective for fiscal years and interim periods within those years beginning after December 15, 2011. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities," to improve reporting and transparency of offsetting (netting) assets and liabilities and the related affects on the financial statements. This ASU is effective for fiscal years and interim periods within those years beginning on or after January 1, 2013. We do not expect the adoption of this ASU will have a material effect on our consolidated financial statements.

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,	
	2011	2010
	(in thousands)	
U.S. Treasury Bonds, stripped of interest, maturing 2020 and 2022, aggregate par value of $1.7 million and $1.7 million, respectively		
Amortized cost	$ 894	$ 839
Gross unrealized gains	455	258
Estimated fair value	$1,349	$1,097

During 2011, 2010, and 2009, the Company recognized approximately $0, $0 and $3 thousand, respectively, of realized gains from its investments in trading and available-for-sale securities. The basis of available for sale securities sold is determined using the specific identification method.

The realized gains for each year results from the disposition of such securities due to the release of the Company's obligation related to securing its commitment under certain repurchase agreements and debentures (Notes C & F).

NOTE B—INVESTMENTS (Continued)

The amortized cost and estimated fair values of available-for-sale securities, by contractual maturity at December 31, 2011 are shown below.

	Amortized cost	Estimated fair value
	(in thousands)	
Due within one year	$ —	$ —
Due after one year through five years	—	—
Due after five years through ten years	475	721
Due after ten years	419	628
Total	$ 894	$ 1,349

NOTE C—LONG-TERM LIABILITIES

	2011	2010
	(in thousands)	
Debentures consist of the following at December 31:		
Secured Convertible Debentures, due December 31, 2020, bearing interest at 12%, due in monthly payments. As of December 31, 2011 and 2010, principal collateralized by $850 thousand and $850 thousand, respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2020.(1)	$ 850	$ 850
Secured Convertible Debentures, due December 31, 2022, bearing interest at 12%, due in monthly payments. As of December 31, 2011 and 2010, principal collateralized by $801 thousand and $801 thousand respectively, principal amount of zero coupon U.S. Treasury Bonds due November 15, 2022.(1)	801	801
	1,651	1,651
Less current maturities	165	165
Long-term portion	$1,486	$1,486

(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

NOTE C—LONG-TERM LIABILITIES (Continued)

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:

2011	Maturity date	Outstanding principal amount	Per share conversion price	Common shares if converted
	(in thousands, except share and per share amounts)			
Secured Convertible 12% Debentures	December 31, 2020	$ 850	$ 35.00	24,285
Secured Convertible 12% Debentures	December 31, 2022	801	35.00	22,885
		$ 1,651		47,170

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, 2011, the estimated principal that can be tendered by the secured holders is as follows:

	(in thousands)
Fiscal year ending December 31:	
2012	$ 165
2013	149
2014	134
2015	120
2016	108
Thereafter	975
	$ 1,651

Long-term liabilities, excluding derivative financial instruments consist of the following at December 31:

	2011	2010
	(in thousands)	
Line of Credit	$ 89,500	$ 69,500
Debentures	1,651	1,651
Debt collateralized by treasury stock	103	245
Asset retirement obligations	15,507	10,217
Litigation allowance	3,100	3,100
Drilling rig obligation	466	2,567
	110,327	87,280
Less current maturities	2,831	3,631
Long-term portion	$ 107,496	$ 83,649

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 note at 10% and the outstanding balance at December 31, 2011 and 2010 was approximately

NOTE C—LONG-TERM LIABILITIES (Continued)

$103 thousand and $245 thousand, respectively, net of discount of approximately $4 thousand and $22 thousand, which is included in other long-term liabilities in 2010. The note requires monthly payments of $13 thousand until August 2012 and is collateralized by treasury stock. In the event of default as defined by the agreement, the only remedy by the note holder will be the issuance of the common stock. During 2010, the Company acquired a drilling rig for a purchase price of $7 million. The Company paid $3.5 million at closing and executed a non-interest bearing secured note for the remaining $3.5 million, payable in fifteen equal monthly payments commencing September 2010.

On December 15, 2011, the Company entered into a five-year $300 million Second Amended and Restated Credit Agreement with Bank of Montreal. This replaced the prior $250 million credit agreement with GE Business Financial Services, Inc. The Credit Facility provides for a revolving credit facility up to the lesser of: (i) $300 million, (ii) the Borrowing Base, or (iii) the Draw Limit requested by the Company. The Credit Facility matures on December 15, 2016, is secured by substantially all of Warren's oil and gas assets, and is guaranteed by the two wholly-owned subsidiaries of the Company.

The initial Borrowing Base is $130 million. The maximum amount available is subject to semi-annual redeterminations of the borrowing base in April and October of each year, based on the value of the Company's proved oil and natural gas reserves in accordance with the lenders' customary procedures and practices. Both the Company and the lenders have the right to request one additional redetermination each year.

The Company is subject to various covenants required by the Credit Facility, including the maintenance of the following financial ratios: (1) a minimum current ratio of not less than 1.0 to 1.0 (including the unused borrowing base and excluding unrealized gains and losses on derivative financial instruments), and (2) a minimum annualized consolidated EBITDAX (as defined in the Credit Facility) to net interest expense of not less than 2.5 to 1.0.

Depending on the amount outstanding and the level of borrowing base usage, the annual interest rate on each base rate loan under the Credit Facility will be, at the Company's option, either: (a) a "LIBOR Loan", which has an interest rate equal to the sum of the applicable LIBOR period plus the applicable "LIBOR Margin" that ranges from 1.75% to 2.75%, or (b) a "Base Rate Loan", or any other obligation other than a LIBOR Loan, which has an interest rate equal to the sum of the "Base Rate", calculated to be 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 one-half percent, plus an applicable "Base Rate Margin" that ranges from 0.75% to 1.75%. As of December 31, 2011, the Company had borrowed $89.5 million under the Credit Facility and was in compliance with all covenants. The weighted average interest rate as of December 31, 2011, was 2.5%.

The Credit Facility also places restrictions on certain additional indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Credit Facility is subject to customary events of default. If an event of default occurs and is continuing, the Agent may, or at the request of the Lenders shall, accelerate amounts due under the Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE D—STOCKHOLDERS' EQUITY

On October 23, 2009, the Company sold 11,775,000 shares of common stock to the public in a secondary offering at a price of $2.60 per share. After deducting the underwriters' commission and offering expenses, the Company received total net proceeds of approximately $28.7 million.

During 2011, the Company issued 155,935 shares of common stock to individuals who exercised options at exercise prices ranging from $0.51 to $2.42 per share. During 2010, the Company issued 249,671 shares of common stock to individuals who exercised options at an exercise price of $0.51 per share.

The preferred stock has an 8% cumulative dividend, payable quarterly. Preferred dividends of approximately $72 thousand ($6.72 per share) and $59 thousand ($5.76 per share) were accrued at December 31, 2011 and 2010, 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.

	Preferred to common
Period	
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 December 31, 2011, holders of the preferred stock may elect to require the Company to redeem their preferred stock at a redemption price equal to the liquidation value of $12 per share, plus accrued but unpaid dividends, if any ("Redemption Price"). Upon the receipt of a redemption election, the Company, at its option, shall either: (1) pay the holder cash in the amount equal to the Redemption Price or (2) issue to holder shares of common stock as defined by the agreement. The Company is accreting the carrying value of its preferred stock to its redemption price using the effective interest method with accretion recorded to additional paid in capital. The accretion of preferred stock results in a reduction of earnings per share applicable to common stockholders. There are 10,703 preferred shares outstanding that the Company may be required to redeem at the aggregate Redemption Price of $0.1 million after December 31, 2011. As noted above, the Company could, at its option, settle the redemption requests in shares of common stock.

During 2010, the Company redeemed 87,409 shares of preferred stock plus accrued dividends, at a cost of approximately $1.3 million.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE D—STOCKHOLDERS' EQUITY (Continued)

Securities Authorized for Issuance Under Compensation Plans

The table below includes information about our equity compensation plans as of December 31, 2011:

	Number of Shares Authorized for Issuance under plan	Number of securities to be issued upon exercise of outstanding options and restricted stock	Weighted-average exercise price of outstanding options and restricted stock	Number of securities remaining available for future issuance under equity compensation plans
2000 Equity Incentive Plan	1,975,000	758,348	$ 6.94	0
2001 Stock Incentive Plan	2,500,000	912,221	$ 4.77	0
2001 Key Employee Stock Incentive Plan	2,500,000	1,257,416	$ 1.45	0
2010 Stock Incentive Plan	6,950,000	780,731	$ 4.10	6,164,202
Total	13,925,000	3,708,716	$ 3.95	6,164,202

During 2011, the Board of Directors approved and the Company issued 143,000 stock options to officers and employees of the Company exercisable at prices ranging from $2.52 to $4.51 per share and 662,562 shares of restricted stock. During 2010, the Board of Directors approved and the Company issued 1,098,500 stock options to officers and employees of the Company exercisable at prices ranging from $2.42 to $3.08 per share and 533,437 shares of restricted stock. During 2009, the Board of Directors approved and the Company issued 1,619,874 stock options to officers and employees of the Company exercisable at prices ranging from $0.51 to $2.06 per share. The options are exercisable at a price not less than the fair market value of the stock at the date of grant, have an exercisable period of five years and generally vest over three years.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE D—STOCKHOLDERS' EQUITY (Continued)

A summary of the status of the Company's options issued to employees as of December 31, 2011, 2010 and 2009 and changes during the years ended on those dates is presented below:

	Incentive options	Weighted Average Exercise Price	
Options outstanding—December 31, 2008	2,477,715	$	10.15
Issued	1,619,874	$	0.56
Expired	(496,800)	$	7.00
Forfeited	(181,749)	$	10.96
Options outstanding—December 31, 2009	3,419,040	$	6.02
Issued	1,098,500	$	2.44
Exercised	(249,671)	$	0.51
Expired	(624,000)	$	9.08
Forfeited	(102,166)	$	4.71
Options outstanding—December 31, 2010	3,541,703	$	4.80
Issued	143,000	$	3.92
Exercised	(155,935)	$	0.79
Expired	(365,750)	$	13.67
Forfeited	(70,033)	$	5.50
Options outstanding—December 31, 2011	3,092,985	$	3.89

NOTE D—STOCKHOLDERS' EQUITY (Continued)

The following table summarizes information about the Company's stock options outstanding at December 31, 2011.

Exercise Price	Options Outstanding at Year End	Weighted Average Remaining Life (In Years)	Options Exercisable at Year End
$0.51	1,136,493	2.18	644,994
$2.06	48,378	2.39	32,252
$2.42	979,698	3.18	319,404
$2.52	10,000	4.75	—
$3.08	40,000	3.38	13,333
$3.09	27,000	4.70	9,000
$4.22	88,000	4.18	—
$4.51	15,000	4.22	—
$10.51	325,666	0.19	325,666
$10.79	20,000	1.59	20,000
$11.15	317,750	1.18	317,750
$12.62	15,000	0.47	15,000
$12.99	20,000	0.38	20,000
$13.10	5,000	1.31	5,000
$13.51	30,000	0.27	30,000
$14.40	15,000	0.78	15,000
Total	**3,092,985**	**2.25**	**1,767,399**

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2011	3,092,985	$ 3.89	2.25	$ 4,026
Exercisable at December 31, 2011	1,767,399	$ 5.41	1.81	$ 2,085

The total intrinsic value of options exercised during the year ended December 31, 2011 and 2010 was $0.5 million and $0.7 million. There were no option exercises in 2009.

As of December 31, 2011 there was $0.7 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 1.4 years.

Cash received from option exercises under all stock-based payment arrangements for the years ended December 31, 2011 and 2010 was $0.1 million and $0.1 million. We issue new shares of common stock to settle option exercises. No options were exercised in 2009.

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NOTE D—STOCKHOLDERS' EQUITY (Continued)

A summary of the status of the Company's restricted stock issued to employees as of December 31, 2011, 2010 and 2009 and changes during the years ended on those dates is presented below:

	Shares	Weighted Average Fair Value
Outstanding at December 31, 2008	131,392	$ 10.96
Vested	(50,279)	10.90
Outstanding at December 31, 2009	81,113	$ 11.00
Granted	533,437	2.42
Vested	(581,439)	3.15
Forfeited	(4,738)	6.97
Outstanding at December 31, 2010	28,373	$ 11.15
Granted	662,562	4.22
Vested	(36,248)	9.67
Forfeited	(38,956)	4.22
Outstanding at December 31, 2011	615,731	$ 4.22

Restricted stock awards for executive officers and employees generally vest ratably over three years, excluding shares granted in March 2010 which vest ratably over nine months. Fair value of our restricted shares is based on our closing stock price on the date of grant. As of December 31, 2011, total unrecognized stock-based compensation expense related to non-vested restricted shares was $1.9 million which is expected to be recognized over a weighted average period of approximately 2.2 years.

All warrants expired during 2010. A summary of the status of the Company's warrants outstanding as of December 31, 2010 and 2009 and changes during the years ended on those dates is presented below:

	Warrants	Weighted Average Exercise Price
Warrants outstanding—December 31, 2008	2,668,108	$ 11.23
Issued	—	
Exercised	—	
Expired	(2,616,070)	$ 11.25
Forfeited	—	
Warrants outstanding—December 31, 2009	52,038	$ 10.24
Issued	—	
Exercised	—	
Expired	(52,038)	$ 10.24
Forfeited	—	
Warrants outstanding—December 31, 2010	—	—

The total intrinsic value of warrants outstanding at December 31, 2010 and 2009 was zero.

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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:

	2011	2010 (in thousands)	2009
Income taxes at federal statutory rate(a)	$ 7,331	$ 6,920	$ (4,697)
Change in valuation allowance	(9,675)	(8,267)	16,497
Nondeductible expenses	574	91	50
State income taxes net of federal benefit	1,294	1,221	(829)
Other	398	6	(10,958)
	$ (78)	$ (29)	$ 63

(a) 34% for 2011, 2010 and 2009.

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

	2011	2010
	(in thousands)	
Deferred tax assets relating to:		
Net operating loss carryforward	$ 99,183	$ 88,008
Oil and gas properties and tangible equipment	34,655	52,001
Stock option expense	2,956	2,595
Unrealized loss on derivatives	480	4,276
Other	324	314
	137,598	147,194
Less valuation allowance	137,416	147,091
Total deferred tax asset	182	103
Deferred tax liabilities relating to:		
Net unrealized gain on investments	182	103
Total deferred tax liability	182	103
Net deferred tax asset (liability)	$ —	$ —

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 (decreased) by approximately ($10 million), ($8 million) and $16 million for the years ended December 31, 2011, 2010 and 2009, respectively.

At December 31, 2011, the Company had net operating loss carryforwards for federal income tax purposes of approximately $248 million, of which approximately $1 million will expire in 2012, with the remaining $247 million to expire in years 2018 through 2030.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE E—INCOME TAXES (Continued)

Tax years beginning in 2007 are subject to examination by taxing authorities, although net operating loss and credit carryforwards from all years are subject to examination and adjustments for at least three years following the year in which the attributes are used.

The Company routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. Only tax positions that meet the more-likely-than-not recognition threshold are recorded.

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, certain executives are 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, 2011, the maximum termination compensation for all executives is approximately $3.6 million.

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, 2011 and 2010, the face amounts of U.S. Treasury Bonds securing the Company's obligation under the Trust Indenture Agreements were $1.7 million and $1.7 million, respectively, and the market values of these U.S. Treasury Bonds were approximately $1.3 million and $1.1 million, respectively (see Note B).

Leases

The Company leases corporate office space in New York City, which expires in January 2014. The Company's oil and gas administrative office in Casper, Wyoming occupies 5,554 square feet under a lease which expires in July 2012. The Company leases office space in Roswell, New Mexico, which expires in May 2013. The Company leases office space in Long Beach, California which expires in August 2020.

NOTE F—COMMITMENTS AND CONTINGENCIES (Continued)

Future minimum annual rental payments, which are subject to escalation and include utility charges as of December 31, 2011, are as follows:

	(in thousands)
Year ending December 31:	
2012	$ 599
2013	566
2014	238
2015	69
2016	—
Thereafter	—
	$ 1,472

Rent expense under these leases was approximately $718 thousand, $728 thousand and $700 thousand for the years ended December 31, 2011, 2010 and 2009, respectively.

Legal Proceedings

In 2005, Warren recorded a provision for $1.8 million relating to a contingent liability that the Company 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 (*Gotham Insurance Company v. Pedeco, Inc., et al.*,) seeking a refund of approximately $1.8 million paid by Gotham and other insurers under an insurance policy issued for a well blow-out that occurred in 1997. After several appeals to the Texas Court of Appeals and the Texas Supreme Court, the case was remanded to the trial court for further proceedings. Both parties filed Motions for Summary Judgment in mid-2009, and on November 19, 2009, the trial court heard oral arguments on both Motions for Summary Judgment. On January 22, 2010, the court granted Gotham's Motion for Summary Judgment for restitution in the amount of $1,823,156 and also awarded prejudgment interest at the rate of 5% per annum in the amount of $976,011. As a result of the January 2010 Summary Judgment, Warren recorded an additional provision of $1.3 million in the fourth quarter of 2009 relating to this contingent liability. On July 7, 2010, Warren E&P posted a supersedeas bond with the court and commenced to appeal the order of the trial court to the Texas Court of Appeals. The San Antonio Court of Appeals assigned and transferred this appeal to the El Paso Court of Appeals. Based on extensions given by the El Paso Court of Appeals, the Frio County District Court Clerk certified and filed the Record on Appeal on October 26, 2010. On March 14, 2011, Warren filed its appellate brief with the El Paso Court of Appeals. Gotham filed its response to Warren's brief on May 31, 2011. Warren replied to Gotham's response on June 23, 2011. The El Paso Court of Appeals held oral arguments of the case on January 12, 2012. The parties are waiting for a decision by the El Paso Court of Appeals. Although Warren believes that it has meritorious grounds for the appeal, if its appeal is unsuccessful, it will pay the amount of restitution to Gotham, as ordered by the trial court.

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.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

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. The Company's 401(k) is a safe harbor matching plan where the Company contributes up to 100% of the participants' 401(k) contributions, up to a maximum of 3% of the participants' compensation plus 50% of the next 2% of the active participants' compensation. The Company's safe harbor match vests immediately. The Company may also make discretionary contributions. The Company's expenses under the plan were approximately $202 thousand, $173 thousand and $137 thousand for the years ended December 31, 2011, 2010 and 2009, respectively.

NOTE H—FAIR VALUE OF FINANCIAL INSTRUMENTS

The estimated fair values of financial instruments recognized in the Consolidated Balance Sheets or disclosed within these Notes to Consolidated Financial Statements have been determined using available market information, information from unrelated third party financial institutions and appropriate valuation methodologies, primarily discounted projected cash flows. However, considerable judgment is required when interpreting market information and other data to develop estimates of fair value.

Short-term Assets and Liabilities. The fair values of cash and cash equivalents, accounts receivable, accounts payable and accrued expenses and other current liabilities approximate their carrying values because of their short-term nature.

U.S Treasury Bonds—Available-For-Sale Securities. The fair values are based upon quoted market prices for those or similar investments and are reported on the Consolidated Balance Sheets at fair value.

Collateral Security Agreement Account (included in other non-current assets). The balance sheet carrying amount approximates fair value, as it earns a market rate.

Fixed Rate 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.

Line of Credit. The carrying amount approximates fair value due the current rates offered to the Company for lines of credit.

	2011		2010	
	Fair value	Carrying amount	Fair value	Carrying amount
	(in thousands)			
Financial assets				
Collateral Security account	$ 3,163	$ 3,163	$ 3,160	$ 3,160
Financial liabilities				
Fixed rate debentures	$ 2,195	$ 1,651	$ 1,901	$ 1,651
Other long-term liabilities	103	103	245	245
Line of credit	89,500	89,500	69,500	69,500

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NOTE H—FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

FAIR VALUE MEASUREMENTS:

Fair value as defined by authoritative literature is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

Level 2: Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter forwards and swaps.

Level 3: Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability.

The valuation assumptions utilized to measure the fair value of the Company's commodity derivatives were observable inputs based on market data obtained from independent sources and are considered Level 2 inputs (quoted prices for similar assets, liabilities (adjusted) and market-corroborated inputs).

The following table presents for each hierarchy level our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis.

December 31, 2011	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets				
Restricted investments in US Treasury Bonds—available for sale, at fair value	$1,349	$ —	$ —	$1,349
Commodity derivatives	$ —	$ 309	$ —	$ 309

	Level 1	Level 2	Level 3	Total
	(in thousands)			
Liabilities				
Commodity derivatives	$ —	$ 980	$ —	$ 980

December 31, 2010	Level 1	Level 2	Level 3	Total
	(in thousands)			
Assets				
Restricted investments in US Treasury Bonds—available for sale, at fair value	$1,097	$ —	$ —	$1,097
Commodity derivatives	$ —	$ 392	$ —	$ 392

NOTE H—FAIR VALUE OF FINANCIAL INSTRUMENTS (Continued)

	Level 1	Level 2	Level 3	Total
		(in thousands)		
Liabilities				
Commodity derivatives	$ —	$ 10,228	$ —	$ 10,228

NOTE I—DERIVATIVE FINANCIAL INSTRUMENTS

To minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas hedge contracts. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices. This price hedging program is designed to moderate the effects of a crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate. Currently, our derivatives are in the form of swaps, long and short calls and costless collars. However, we may use a variety of derivative instruments in the future to hedge. The Company has not designated these derivatives as hedges.

The following table summarizes the open financial derivative positions as of December 31, 2011 related to oil and gas production. The Company will receive prices as noted in the table below and will pay a counterparty market price based on the NYMEX (for natural gas production) or WTI (for oil production) index price, settled monthly.

Product	Type	Contract Period	Volume	Price per Mcf or Bbl
Crude Oil	Put	01/01/12 - 12/31/12	1,000 Bbl/d	$ 70.00
Natural Gas Differential	Swap	01/01/12 - 12/31/12	3,000 Mcf/d	$ (0.51)*

* This represents a differential spread between NYMEX and CIG pricing.

The tables below summarize the amount of gains (losses) recognized in income from derivative instruments not designated as hedging instruments under authoritative guidance.

Derivatives not designated as Hedging Instrument under authoritative guidance	For the Years Ended December 31, 2011	2010	2009
	(in thousands)		
Realized cash settlements on hedges	$(12,216)	$ 2,745	$ (1,501)
Unrealized gain (loss) on hedges	9,490	(1,217)	(9,472)
Total	$ (2,726)	$ 1,528	$(10,973)

NOTE I—DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

The table below reflects the line item in our Consolidated Balance Sheet where the fair value of our net derivatives, are included.

December 31, 2011	Derivative Assets Balance Sheet Location	Fair Value
	(in thousands)	
Commodity—Natural Gas	current	309
Total derivatives not designated as hedging instruments		$ 309

December 31, 2011	Derivative Liabilities Balance Sheet Location	Fair Value
	(in thousands)	
Commodity—Oil	current	(980)
Total derivatives not designated as hedging instruments		$ (980)

December 31, 2010	Derivative Assets Balance Sheet Location	Fair Value
	(in thousands)	
Commodity—Natural Gas	Non-current	(92)
Commodity—Oil	Non-current	484
Total derivatives not designated as hedging instruments		$ 392

December 31, 2010	Derivative Liabilities Balance Sheet Location	Fair Value
	(in thousands)	
Commodity—Natural Gas	current	72
Commodity—Oil	current	(9,697)
Commodity—Oil	Non-current	(603)
Total derivatives not designated as hedging instruments		$ (10,228)

Derivative's Credit risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE I—DERIVATIVE FINANCIAL INSTRUMENTS (Continued)

As of December 31, 2011, the counterparties to the Company's commodity derivative contracts consist of two financial institutions. The Company's counterparties or their affiliates are also lenders under the Company's Senior Credit Agreement. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's Senior Credit Agreement. The Company is not generally required to post additional collateral under derivative agreements.

The Company's derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company were to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time.

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:

	2011	2010	2009
		(in thousands)	
Property acquisition—unproved	$ —	$ —	$ —
Property acquisition—proved	509	1,685	14
Exploration costs	8,147	204	318
Development costs	63,675	26,220	3,995
	$ 72,331	$ 28,109	$ 4,327

Asset retirement cost included in oil and gas property costs increased by approximately $5.3 million in 2011, increased by $1.4 million in 2010 and increased by approximately $0.2 million in 2009.

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

	2011	2010
	(in thousands)	
Unproved oil and gas properties	$ 22,963	$ 25,732
Proved oil and gas properties	657,445	582,458
	680,408	608,190
Less accumulated depreciation, depletion, amortization and impairment expense	404,965	376,444
	$ 275,443	$ 231,746

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE J—OIL AND GAS INFORMATION (Continued)

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

	2011	2010	2009
		(in thousands)	
Revenues	$ 103,371	$ 88,275	$ 63,402
Production costs	(30,637)	(28,845)	(27,097)
Accretion of asset retirement obligation	(995)	(820)	(785)
Depreciation, depletion, amortization	(27,914)	(20,265)	(18,707)
Income from oil and gas producing activities	$ 43,825	$ 38,345	$ 16,813

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.

The following is a summary of Warren's oil and gas properties not subject to amortization as of December 31, 2011:

	Costs incurred in				
	Fiscal year 2011	Fiscal year 2010	Fiscal year 2009	Prior to 2009	Total
			(in thousands)		
Acquisition costs	$ —	$ —	$ —	$ 834	$ 834
Exploration costs	60	—	—	—	60
Development costs(1)	161	266	860	20,782	22,069
Total oil and gas properties not subject to amortization	$ 221	$ 266	$ 860	$ 21,616	$ 22,963

(1) The Company's development costs primarily reflect investment in well cellars and facilities in its Wilmington oil field to facilitate the development of future oil wells. These costs will be allocated to future wells drilled, the majority of these wells are expected to be drilling during the next five to eight years.

NOTE K—OIL AND GAS RESERVE DATA (UNAUDITED)

The following estimates of proved reserve quantities and related standardized measure of discounted future 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

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

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 for were computed by applying 12-month average prices for 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%.

The following summaries of changes in reserves and standardized measure of discounted future net cash flows were prepared from estimates of proved reserves provided by Netherland, Sewell & Associates, Inc. for 2011 and Williamson Petroleum Consultants, Inc., for 2010 and 2009.

Summary of Changes in Proved Reserves

	Year ended December 31,					
	2011		2010		2009	
	Mbbls	Mmcf	Mbbls	Mmcf	Mbbls	Mmcf
Proved reserves						
Beginning of year	10,250	68,200	10,221	62,900	9,414	72,825
Purchase of reserves in place	—	—	—	3,037	—	—
Discoveries and extensions	3,744	—	658	—	—	8,380
Revisions of previous estimates	1,880	(19,320)	340	6,915	1,760	(14,420)
Production	(911)	(5,020)	(969)	(4,652)	(953)	(3,885)
End of year	14,963	43,860	10,250	68,200	10,221	62,900
Proved developed reserves						
Beginning of year	7,518	49,300	7,933	49,868	6,498	52,762
End of year	8,348	28,515	7,518	49,300	7,933	49,868
Proved undeveloped reserves						
Beginning of year	2,732	18,900	2,288	13,032	2,916	20,063
End of year	6,615	15,345	2,732	18,900	2,288	13,032

(a) Undeveloped reserves transferred to developed reserves were 1.3 MMBoe for the year ended December 31, 2011. Capital costs incurred to convert these proved undeveloped reserves to proved developed reserves were $24.3 million.

(b) The Company revised its 2011 year-end proved natural gas reserves downward by 19.3 Bcfe. Negative revisions decreased proved natural gas reserves by a net amount of 11.3 Bcfe due to performance and 8.0 Bcfe as a result of changes in the Company's future development plans.

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

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

(c) The Company revised its 2011 year-end proved oil reserves upward by 5.6 MMbbls. In 2011, total extensions and discoveries of 3.7 MMbbls resulted from the Company's drilling and completion activities in the Wilmington Townlot Unit in California. Additionally, proved reserves increased 1.9 MMbbls primarily resulting from improved well performance in the Wilmington Townlot Unit in California.

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

	December 31,		
	2011	2010	2009
	(Amounts in thousands)		
Future cash inflows	$ 1,708,079	$ 1,033,221	$ 757,883
Future production costs and taxes	(514,968)	(466,507)	(326,130)
Future development costs	(254,982)	(84,606)	(21,314)
Future income tax expenses	(108,977)	—	—
Net future cash flows	829,152	482,108	410,439
Discounted at 10% for estimated timing of cash flows	(343,146)	(194,480)	(169,147)
Standardized measure of discounted future net cash flows	$ 486,006	$ 287,628	$ 241,292

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

	Year ended December 31,		
	2011	2010	2009
	(Amounts in thousands)		
Sales, net of production costs and taxes	$ (72,734)	$ (59,430)	$ (36,305)
Discoveries and extensions	152,973	15,994	6,915
Purchases of reserves in place	—	721	—
Changes in prices and production costs	196,010	119,779	60,117
Revisions of quantity estimates	56,710	17,619	16,546
Development costs incurred	30,892	5,544	1,248
Net changes in development costs	(149,662)	(68,497)	(16,258)
Interest factor—accretion of discount	28,763	24,129	19,399
Net change in income taxes	(40,070)	—	—
Changes in production rates (timing) and other	(4,504)	(9,523)	(4,358)
Net (decrease) increase	198,378	46,336	47,304
Balance at beginning of year	287,628	241,292	193,988
Balance at end of year	$ 486,006	$ 287,628	$ 241,292

Estimated future net cash flows represent an estimate of future net revenues from the production of proved reserves using average prices for 2011, 2010 and 2009 along with estimates of the operating

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

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

costs, production taxes and future development and abandonment costs (less salvage value) necessary to produce such reserves. The prices used at December 31, 2011, 2010 and 2009 were $104.75, $73.30 and $54.33 per Bbl and $3.21, $4.13 and $3.22 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 including abandonment 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 through December 31, 2015 are $188.7 million.

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 Company's net operating loss carryforward was sufficient to fully absorb any future income taxes from oil and gas operations in 2009 and 2010.

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, 2011 and 2010 are as follows:

	2011				
	Quarter				
	First	Second	Third	Fourth	Year
	(in thousands, except per share amounts)				
Revenues	$ 23,180	$ 26,893	$ 26,018	$ 27,280	$ 103,371
Gross profit	15,445	18,187	18,124	20,978	72,734
Net income (loss)	(576)	9,030	10,184	3,001	21,639
Net income (loss) applicable to common stockholders	(579)	9,027	10,181	3,000	21,629
Earnings (loss) per share					
Basic	$ (0.01)	$ 0.13	$ 0.14	$ 0.04	$ 0.31
Diluted	$ (0.01)	$ 0.13	$ 0.14	$ 0.04	$ 0.30

Warren Resources, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

December 31, 2011, 2010 and 2009

NOTE L—QUARTERLY INFORMATION (UNAUDITED) (Continued)

	2010				
	Quarter				
	First	Second	Third	Fourth	Year
	(in thousands, except per share amounts)				
Revenues	$ 21,589	$ 20,982	$ 23,117	$ 22,587	$ 88,275
Gross profit	14,358	14,248	15,451	15,373	59,430
Net income	7,186	8,563	4,320	314	20,383
Net income applicable to common stockholders	7,175	8,560	4,317	313	20,365
Earnings per share					
Basic and diluted	$ 0.10	$ 0.12	$ 0.06	$ 0.00	$ 0.29

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. Gross profit represents oil and gas revenues less lease operating expenses.

WARREN RESOURCES, INC.

FORM 10-K

December 31, 2011

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INDEX TO EXHIBITS

Exhibit
No.
Description

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(11)	Articles of Incorporation of Registrant filed May 20, 2004 (Maryland)
3.2(8)	Bylaws of the Registrant, dated June 2, 2004
3.3(8)	Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.4(8)	Certificate of Correction to Articles Supplementary (Series A 8% Cumulative Convertible Preferred Stock) (Maryland)
3.5(8)	Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock ($.0001 Par Value) (Maryland)
3.6(8)	Certificate of Correction to Articles Supplementary (Series A Institutional 8% Cumulative Convertible Preferred Stock) (Maryland)
4.1(11)	Specimen Stock Certificate for Common Stock (Maryland)
4.2(6)	Form of Class A Common Stock Warrant
4.3(6)	Form of Class B Common Stock Warrant
4.4(2)	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(4)	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(8)	Form of Subscription and Registration Rights Agreement dated July 30, 2004 by and between Warren Resources, Inc. and the Accredited Investors in Warren Resources, Inc.'s private placement dated July 9, 2004
4.7(17)	Rights Agreement, dated as of August 29, 2008
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(7)*	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Norman F. Swanton
10.8(13)*	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Norman F. Swanton

Exhibit No.	Description
10.9(7)*	Amendment to Employment Agreement dated January 1, 2004, between the Registrant and Timothy A. Larkin
10.10(13)*	Second Amendment to Employment Agreement dated June 17, 2005, between the Registrant and Timothy A. Larkin
10.11(13)*	Employment Agreement dated as of July 1, 2005, between the Registrant and Lloyd Davies
10.12(13)*	Employment Agreement executed on June 17, 2005, between the Registrant and David E. Fleming
10.13(8)*	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(3)	Exchange Agreement dated as of the 11th day of December, 2002, between Anadarko E&P Company LP, and Warren Resources, Inc.
10.17(3)	Joint Exploration Agreement, dated December 13, 2002 between Warren Resources, Inc., Anadarko E&P Company LP, and Anadarko Land Corp.
10.18(3)	Form of Rocky Mountain Unit Operating Agreement Between Anadarko E&P Company, LP and Warren Resources, Inc.
10.19(9)	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(9)	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(12)	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
10.22(14)	Form of Asset Purchase Agreement
10.23(15)	First Amendment to Credit Agreement dated as of August 9, 2007 amount Warren Resources, Inc., the lenders party thereto and JP Morgan Chase Bank, N.A.
10.24(16)	Amended and Restated Credit Agreement dated as of November 19, 2007 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Merrill Lynch Capital, a Division of Merrill Lynch Business Financial Services Inc., as Administrative Agent, as a Lender and as Sole Bookrunner and Sole Lead Arranger, and the additional Lenders party thereto
10.25(18)	General Release and Severance Agreement with Lloyd G. Davies dated effective as of January 1, 2009
10.26(19)	Form of Change in Control Agreement, dated as of May 9, 2009, between Warren Resources, Inc. and certain employees of Warren Resources, Inc.
10.27(20)	First Amendment to Amended and Restated Credit Agreement dated as of May 12, 2009 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Merrill Lynch Capital, a Division of Merrill Lynch Business Financial Services Inc., as Administrative Agent, as a Lender and as Sole Bookrunner and Sole Lead Arranger, and the additional Lenders party thereto

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Exhibit No.	Description
10.28(21)*	2010 Stock Incentive Plan
10.29(22)	Second Amended and Restated Credit Agreement dated as of December 15, 2011 among Warren Resources, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Bank of Montreal, as Administrative Agent, as a Lender and the additional Lenders party thereto.
10.30(23)	Coalbed Natural Gas (CBNG) Unit Agreement for the Development and Operation of the Spyglass Hill (CBNG) Unit area. Count of Carbon, State of Wyoming, dated February 26, 2011, by and between the parties identified therein
10.31(23)	Unit Operating Agreement Spyglass Hill (CBNG) Unit Area, dated February 26, 2011, by and among the parties identified therein.
11(24)	Statements regarding Computation of Per Share Earnings (Included in the Financial Statement in Part 4)
14(5)	Code of Ethics for Senior Financial Officers
21.1(10)	Subsidiaries of the Registrant
23.1(24)	Consent of Williamson Petroleum Consultants, Inc., Independent Petroleum Engineer
23.2(24)	Consent of Grant Thornton LLP
23.3(24)	Consent of Netherland, Sewell & Associates, Inc.
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
99.1(23)	Report of Williamson Petroleum Consultants, Inc., Independent Petroleum Engineer
99.2(24)	Report of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineer
101(24)	The following materials from the Warren Resources, Inc. Annual Report on Form 10-K for the year ended December 31, 2011 (and related periods), formatted in XBRL (eXtensible Business Reporting Language) include (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Stockholders' Equity and Comprehensive Income, (iv) the Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements.

* Denotes a management contract or compensatory plan or arrangement.

** Users of this data are advised pursuant to Rule 401 of Regulations S-T that the financial information contained in the XBRL-Related Documents is unaudited. Furthermore, users of this data are advised in accordance with Rule 406T of Regulations S-T promulgated by the Securities and Exchange Commission that this Interactive Data File is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these Sections.

(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 Current Report on Form 8-K, Commission File No. 000-33275, filed on December 17, 2002.

(3) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed on December 24, 2002.

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

(5) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2002, Commission File No. 000-33275, filed on March 31, 2003.

(6) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, Commission File No. 000-33275, filed on March 15, 2004.

(7) Incorporated by reference to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2004, Commission File No. 000-33275, filed May12, 2004.

(8) Incorporated by reference to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, Commission File No. 000-33275, filed on August 13, 2003.

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

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

(11) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 000-33275, filed on March 17, 2005.

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

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

(14) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed June 22, 2007.

(15) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed August 21, 2007.

(16) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed November 20, 2007.

(17) Incorporated by reference to the Company's Form 8-A filed on September 5, 2008, Commission File No. 001-34169.

(18) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed January 7, 2009.

(19) Incorporated by reference to the Company's Quarterly Report on Form 10-Q, Commission File No. 000-33275, filed August 5, 2009.

(20) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed May 15, 2009.

(21) Incorporated by reference to the Company's Definitive Proxy Statement on Form DEF 14-A filed on April 8, 2010.

(22) Incorporated by reference to the Company's Current Report on Form 8-K, Commission File No. 000-33275, filed December 16, 2011.

(23) Incorporated by reference to the Company's Annual Report on Form 10-K/A, Commission File No. 000-33275, filed October 27, 2011.

(24) Incorporated by reference to the Company's Annual Report on Form 10-K for the year ended December 31, 2011, Commission File No. 000-33275, filed March 6, 2012.

† Filed herewith.

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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/A 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: April 5, 2012

/s/ NORMAN F. SWANTON

Norman F. Swanton,
Chairman and Chief Executive Officer

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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/A 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: April 5, 2012

/s/ TIMOTHY A. LARKIN

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

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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/A for the year ending December 31, 2011 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, Chief Financial Officer and Principal Accounting 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.

April 5, 2012

/s/ NORMAN F. SWANTON

Norman F. Swanton
Chairman and Chief Executive Officer

/s/ TIMOTHY A. LARKIN

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

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