MAXIM TEP, INC
Form 10-12G/A
July 23, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Amendment No. 3
on
FORM 10

General Form for Registration of Securities
Pursuant to Section 12(b) or (g) of the
Securities Exchange Act of 1934

MAXIM TEP, INC.
(Exact name of registrant as specified in its charter)

Texas	**20-0650828**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

9400 Grogan's Mill Road, Suite 205
The Woodlands, Texas 77380
www.maximtep.com

Address of principal executive offices)

Registrant's Telephone Number, Including Area Code: **(281) 466-1530**

Securities to be registered pursuant to Section 12(b) of the Act: **None**

Securities to be registered pursuant to Section 12(g) of the Act:

Common Stock, par value $0.00001
(Title of Class)

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. (Check one):

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

MAXIM TEP, INC.

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Forward Looking Statements

This Registration Statement on Form 10 contains forward-looking statements concerning our beliefs, plans, objectives, goals, expectations, anticipations, estimates, intentions, operations, future results and prospects, including statements that include the words “may,” “could,” “should,” “would,” “believe,” “expect,” “will,” “shall,” “anticipate,” “esti “plan” and similar expressions. These forward-looking statements are based upon current expectations and are subject to risk, uncertainties and assumptions, including those described in this Registration Statement on Form 10. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual results may vary materially from those anticipated, estimated, expected, projected, intended, committed or believed. We provide the following cautionary statement identifying important factors (some of which are beyond our control) which could cause the actual results or events to differ materially from those set forth in or implied by the forward-looking statements and related assumptions.

PART I

ITEM 1. BUSINESS

(A) *GENERAL*

Maxim TEP, Inc. (“Maxim” or the “Company”), is headquartered in The Woodlands, Texas, a suburb of Houston. The Company is an oil and natural gas exploration, development and production (E&P) company geographically focused on the onshore United States. The Company’s operational focus is the acquisition, through the most cost effective means possible, of production or near production of oil and natural gas field assets. Targeted fields generally have existing wells that are often past primary energy recovery, but whose enhancement through secondary and tertiary recovery methods could revitalize them. Targeted fields also have the availability of additional drilling sites. The Company seeks to have an inventory of existing wells to enhance and a number of new drilling sites to maintain growth, while increasing reserves and cash flow. Maxim uses both conventional and non-conventional methods to bring non-producing wells back into production and to minimize operational costs.

(B) *HISTORY AND DEVELOPMENT*

During October of 2003, the founders conceived a business plan and named the Company Maxim Energy, Inc. On September 23, 2004 Maxim Energy, Inc. merged into Maxim TEP, Inc., a Texas corporation, which resulted in Maxim TEP, Inc. as the surviving entity headquartered in The Woodlands, Texas. The founders began to acquire oil and natural gas properties during 2004 with its first acquisition being a property in Oklahoma. Acquisition of properties continued in 2005 and 2006 and the Company now owns fields in Louisiana, Arkansas, Kentucky and New Mexico.

The Company has a three phases of development:

- § Phase One – Acquisition Phase: Acquire property and oil and natural gas leases as budgets would allow while carefully selecting targeted properties that met the Company’s long range objectives.
- § Phase Two – Development Phase: Drill development wells in careful “step outs” from known reserve areas to raise likelihood of productive new wells and enhance existing wells with secondary and tertiary recovery technologies available to the Company. The goal is to drill, complete and produce as much oil and natural gas as possible thereby increasing proved reserves and cash flows so as to support Phase Three.
- § Phase Three – Expansion Phase: During this phase, the Company would continue to expand and replace production that it is selling into the market, offset historic decreases in production and monetize fields at appreciated values from their original purchase price.

Phase One – Acquisition Phase

The Company's fundamental belief was premised on the proposition that oil prices would increase because world supplies were diminishing while worldwide demand was increasing. The founders are believers in "Peak Oil," a belief that recognizes that since the production and extraction of oil and natural gas has grown almost every year and (It is currently at about 84 million barrels a day) production is likely to start a decline so we will have "peaked," a theory first espoused by M. King Hubbert in the 1950's who predicted the peak to occur between 1965-1970 and actually did occur in the lower 48 states in 1970-1971. Mr. Hubbert believed in the 1950's, the world would use more than half its supply in the near future, then the industry would shift from a buyers' market to a sellers' market since oil production would more than likely stop growing and start a decline. The founders held that this decline would lead to higher prices and attention towards secondary and tertiary oil and gas recovery from older fields. By acquiring fields first, the belief was that prices would be lower than when the market realized the importance of older fields. Hence, many oil and natural gas fields were inexpensive as they were not economical, given the then-oil-and-gas prices. Nevertheless, these fields could become economical if oil and natural gas prices rose, giving the owner the potential to eventually monetize at higher energy prices.

The Company sought financing for its Phase One. Maxim secured initial funding from several accredited investors, and set out to acquire fields, and now currently owns the rights to oil and natural gas leases in Kentucky, Louisiana, Arkansas and New Mexico.

In buying existing oil and natural gas fields, the Company set out to extensively study the fields, the formations in which oil and natural gas were found, the history of sales from the field and the history of all surrounding fields, and their production. From this information, a better assessment could be made as to the value of the target property.

Phase Two – Development Phase

Phase Two is the monetization of the Company's fields through secondary and tertiary recovery methods in existing wells, as well as the development through drilling of the undeveloped acreage that exist in its fields. The Company has the availability to workover over 530 wells through secondary and tertiary advanced stimulation methods. The Company also believes it has at least 2,159 drillable sites across all of its fields. This phase is highly dependent on the Company's ability to secure funding from debt and equity sources.

Currently, the Company has active drilling, completion and operations on several of its fields located in Kentucky, Arkansas and Louisiana. The Company has 515 small productive natural gas wells in its Marion field in Louisiana that it received from the purchase of this field along with over 110 miles of natural gas gathering pipeline. It has plans to repair or put in place new pipeline to more efficiently capture additional natural gas from these existing wells. The Company began an eight-well drilling program in its Belton Field in Kentucky, resulting in three gas wells, three oil wells and one water well (for disposal purposes). The eighth well has not yet been drilled. The drilled wells are in different stages of completion. First production began in the fourth quarter of 2007. The Company has begun a workover program on existing wells in its Days Creek Field in Arkansas. The Company began four wells of a six-well drilling program in its Stephens Field in Arkansas, of which two are in production. Lastly, the Company has twelve oil wells in the Delhi Field in Louisiana and is beginning an active well workover program on them.

The Company initiated its Phase Two drilling and work-over program in late 2006 and early 2007. In 2008-09, Maxim intends to drill or enhance a total of 40 wells should it receive adequate funding.

In 2008-09 the Company plans to: work-over and enhance 10 existing oil wells and one injection well in the Days Creek Field; drill seven new wells in the Days Creek Field; workover 12 oil wells and four injection wells in Delhi Field; drill an injection well in the Belton Field; drill four wells in the deeper zone of the Stephens Field; and to complete one shallow well already drilled in the Stephens Field. While there are no assurances of success with all new wells, it is anticipated that this drilling plan, coupled with well enhancements in Marion and Delhi, could contribute significant additional production by December 2008.

The following table sets forth the Company's 2008-09 planned oil and injection wells to drill or enhance.

	Wells Planned to Drill or Enhance in 2008-09	**Active Wells December 2007**
Marion–Louisiana	—	476
Days Creek–Arkansas	18	4
Delhi–Louisiana	16	—
Belton–Kentucky	1	2
South Belridge–California (sold in 2008)	—	9
Stephens (Deep)–Arkansas	4	2
Stephens (Jones)–Arkansas	1	—
Total	40	493

All of the planned drilling and enhancements assume that the Company is successful in securing its 2008 funding that will support a drilling and development budget of approximately $12.4 million. The actual number of wells drilled will vary depending upon various factors, including the availability and cost of drilling rigs, any working interest partner issues, our ability to raise additional capital, the success of our drilling programs, weather delays and other factors. If we drill the number of wells we have budgeted for 2008-09, depreciation, depletion and amortization, oil and natural gas operating expenses and production are expected to increase over levels incurred in 2007. Our ability to drill this number of wells is heavily dependent upon the timely access to oilfield services, particularly drilling rigs. The shortage of available rigs and financing in 2007 delayed the drilling and enhancement of several planned wells, slowing our growth in production. Due to limited funding, as of May 2008, the Company has only partially begun these planned 2008 activities and foresees the plan to extend into 2009, if funding is obtained.

Phase Three – Expansion Phase

In the Phase Three development of the Company, an effort will be made to replace the oil and natural gas reserves currently being developed in fields operated by the Company. Monetizing fields through the creation of Master Limited Partnerships ("MLP") is also an option that offers cash flow to investors and the Company. With the enhanced oil recovery ("EOR") methods available to the Company there are fields that it can acquire, either for development of reserves, enhancement, or monetization through resale. See EOR discussed in more detail on Page 7.

(C) ***DESCRIPTION OF FIELDS***

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2007. "Developed Acreage" refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities. "Undeveloped Acreage" refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and natural gas in commercial quantities whether or not the acreage contains proved reserves.

	2007 Production BOE	12/31/2007 Proved Reserves-BOE	Average Working Interest	Developed Acreage Gross	Developed Acreage Net	Undeveloped Acreage Gross	Undeveloped Acreage Net	Total Acreage Gross	Total Acreage Net
Marion–LA	36,627	298,025	100.00%	10,300	10,300	11,200	11,200	21,500	21,500
Days Creek–AR	7,246	551,959	85.00%	480	408	260	221	740	629
Delhi–LA	5,203	1,976,170	95.77%	520	498	880	843	1,400	1,341
Hospah–NM	—	—	100.00%	—	—	2,080	2,080	2,080	2,080
Belton– KY	803	5,580	100.00%	110	110	9,215	9,215	9,325	9,325
South Belridge–CA	22,261	60,814	50.00%	45	23	1,830	915	1,875	938
Stephens (Deep)–AR	705	38,170	24.00%	80	19	1,034	248	1,114	267
Stephens (Jones)–AR	—	24,890	75.00%	—	—	40	30	40	30
Total	72,845	2,955,608		11,535	11,358	26,539	24,752	38,074	36,110

An element of an oil or natural gas lease is the obligation to drill upon the fields that are acquired. If the Company is not successful in securing its 2008 funding for a drilling and development budget of approximately $12.4 million, some of leases might be lost. So as to maintain its leases in the Stephens Field, six wells must be drilled by the end of 2008 or the Company will lose its rights to the undeveloped acres. The Company has already drilled four of these wells. The South Belridge Field lease carries a 10 well per year drilling commitment or the remaining undeveloped acres could be lost, but the Company's working interest partner and the operator has been complying with this commitment even without the Company's contribution. In that scenario, the Company only forfeits the well spacing acres of any wells in which it chooses to go non-consent. The Marion Field, Days Creek Field, and Delhi Field do not have any future drilling commitments and current production is sufficient to maintain those leases. The Company is the mineral interest owner in its initial 3,008 acres of the Belton Field and therefore there is no drilling or production requirements on this property. During 2007, the Company has leased an additional 6,317 surrounding acres, typically under five year leases with an option to renew the lease for an additional five years for a rental fee.

A description of the Company’s producing oil and natural gas properties is as follows:

Marion Field (Monroe Gas Field), Louisiana

The Company purchased this approximately 21,500 acre natural gas field in December 2005 which included a pipeline and operational equipment.

- Wells: 476 currently producing though existing pipeline needs modernization and enhancement
- The Company currently has a 100% working interest (“WI”) and an average net revenue interest (“NRI”) of 76%
- Natural gas production from the Arkadelphia zone
- Strategic plan initiated for natural gas field workover program to increase production revenue, and pipeline replacement/repair program to handle increased production of natural gas
- Developing strategic plan for exploration and development of deeper prospective pay zones

Days Creek Field, Arkansas

In November 2006, the Company purchased approximately 740 acres in Miller County Arkansas using $400,000 in cash and three convertible notes in an aggregate principal amount of $6.0 million, which notes are convertible into an aggregate of 8,000,000 shares of common stock.

- Wells: 13 existing wells with ten planned workovers
- The Company currently has a 85% WI and a 57.25% NRI
- There are four actively operating oil and natural gas wells in the Smackover Zone
- Developing strategic plan for additional in-field drilling and development

Delhi Field, Louisiana

The Company purchased an approximately 1,400 acre lease in December 2006 that is a water injection oil field.

- Proved oil reserves in the Mengel Sands
- Wells: 12 productive wells are in place and completed
- The Company currently has a 95.77% WI and a 82.67% NRI
- Active well workover program on existing oil wells
- Developing strategic plan for implementation of waterflood program

Hospah, Lone Pine & Clovis Oil and Natural Gas Fields, New Mexico

Over the course of two years, the Company has negotiated and continues to negotiate the purchase of acreage in New Mexico. We currently have acquired leases to 2,080 acres in Hospah while working towards leasing more acreage near Clovis, New Mexico in McKinley County.

- The Company has a 100% WI and an 73.3% NRI on its first 2,080 acres in Hospah
- Oil and natural gas production since 1927 from the Hospah Sandstones reservoir located on the field have yielded nearly 22 million barrels of oil and nearly 53 bcf of gas through 2005

Belton Field, Kentucky

The Belton Field was the Company’s first acquisition in April of 2004, acquiring 3,008 acres initially and since that time the Company has leased an additional 6,317 surrounding acreage, all located in Muhlenberg County, Kentucky.

- Wells: three oil wells and three natural gas wells are newly drilled and in various stages of completion with one additional well not yet drilled
- The Company currently has a 100% WI and an approximate 79.6% NRI
- A drilling program is nearly completed to develop shallow reserves and explore for deeper productive oil and natural gas pay zones

South Belridge Field, California

The Company negotiated a joint operating agreement ("JOA") with Orchard Petroleum, Inc. in February 2005 on a prospect of approximately 960 acres in Kern County, California. The Company spent a total of $1.72 million for the opportunity to buy into this project with Orchard for a 75% working interest of Orchard's 75% interest. In addition, the Company was obligated to pay for the first $28.5 million in capital expenditures (CAPEX) to drill wells, later reduced to $23.5 million for a 50% working interest. In support of Orchard's drilling operations, the Company invested the $23.5 million on wells drilled in the South Belridge field for a total investment of $25.2 million including the initial $1.72 million buy in. In early 2007, the Company paid $500,000 for a 50% working interest in 600 acres of section 18 which is adjacent to the original 960 acre prospect. The Company sold this property in April 2008 to reduce outstanding debt.

Stephens Field, Arkansas

The Company purchased rights to approximately 1,114 acres in Columbia County, Arkansas in December 2006. The Company also bought into the single well in Lafayette County, Arkansas, the Jones #1 well, in 2007.

- Wells: five wells drilled and two of those wells are completed
- The Company currently has a 24% WI and a 16.5% NRI at depths of 2,500 feet and deeper
- The Company currently has a 75% WI and a 45.75% NRI in the Jones #1 well

(D) ***OIL AND NATURAL GAS OPERATIONS, PRODUCTION AND DEVELOPMENT***

Volumes, Prices and Oil & Natural Gas Operating Expense

The following table sets forth certain information regarding the production volumes of, average sales prices received for and average production costs associated with our sales of oil and natural gas for the periods indicated.

	Year Ended December 31,	
	2007	**2006**
Production volumes:		
Oil (Bbls)	23,880	16,167
Natural gas (Mcf)	293,788	313,585
Barrel of oil equivalent (BOE)	72,845	68,431
Average sales prices:		
Oil (per Bbl)	$ 71.77	$ 62.57
Natural gas (per Mcf)	$ 6.20	$ 6.27
Barrel of oil equivalent (per BOE)	$ 48.54	$ 43.54
Average costs (per BOE) *(1)*	$ 43.36	$ 30.91

(1) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies), workover costs and the administrative costs of production offices, insurance and property and severance taxes.

Oil and Natural Gas Reserves

The reserves as of December 31, 2007 were derived from reserve estimates prepared by the independent reserve engineers; Aluko & Associates, Inc. for the Delhi Field and the South Belridge Field, Haas Petroleum Engineering Services, Inc. for the Belton Field and the Stephens Field, Netherland, Sewell & Associates, Inc. for the Marion Field, and Lee Keeling and Associates, Inc. for the Days Creek Field. No reserve reports were provided to any government agency. The PV-10 value was derived using constant prices as of the calculation date, discounted at 10% per annum on a pretax basis, and is not intended to represent the current market value of the estimated oil and natural gas reserves owned by the Company. For further information concerning the present value of future net revenues from these proved reserves, see Note 14 of notes to Consolidated Financial Statements.

The following table sets forth our estimated net proved oil and natural gas reserves and the PV-10 value of such reserves as of December 31, 2007.

	Proved Reserves		
	Developed	**Undeveloped**	**Total**
Oil and condensate (Bbls)	143,806	2,480,489	2,624,295
Natural gas (Mcf)	1,987,875	—	1,987,875
Total proved reserves (BOE)	475,119	2,480,489	2,955,608
PV-10 Value *(1)(2)*	$ 4,845,085	$ 100,019,176	$ 104,864,261

(1) The PV-10 value as of December 31, 2007 is pre-tax and was determined by using the December 31, 2007 sales prices, which averaged $92.79 per Bbl of oil, $6.46 per Mcf of natural gas. Management believes that the presentation of PV-10 value may be considered a non-GAAP financial measure. Therefore we have included a reconciliation of the measure to the most directly comparable GAAP financial measure (standardized measure of discounted future net cash flows in footnote (2) below). Management believes that the presentation of PV-10 value provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because many factors that are unique to each individual Company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors 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.

Management also uses this pre-tax measure when assessing the potential return on investment related to its oil and natural gas properties and in evaluating acquisition candidates. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and natural gas reserves owned by us. The PV-10 value should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(2) Future income taxes and present value discounted (10%) future income taxes were $29,301,076 and $16,026,188, respectively. Accordingly, the after-tax PV-10 value of Total Proved Reserves (or "Standardized Measure of Discounted Future Net Cash Flows") is $88,838,073.

Development, Exploration and Acquisition Capital Expenditures

The following table sets forth certain information regarding the gross costs incurred in the purchase of proved and unproved properties and in development and exploration activities.

	Year Ended December 31,	
	2007	**2006**
Property acquisition costs:		
Unproved	$ 778,312	$ 6,094,136
Proved	4,726,215	5,929,225
Exploration costs	3,227,137	85,453
Development costs	3,704,171	7,446,629
Asset retirement obligation *(1)*	330,299	890,355
Total costs incurred	$ 12,766,134	$ 20,445,798

(1) Includes non-cash asset retirement obligations accrued in accordance with SFAS No. 143 of $330,299 and $890,355, respectively, for the years ended December 31, 2007 and 2006, respectively.

Productive Wells

Productive wells are producing wells or wells capable of production. This does not include water source wells, water injection wells or water disposal wells. Productive wells do not include any wells in the process of being drilled and completed that are not yet capable of production, but does include old productive wells that are currently shut-in, because they are still capable of production. The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2007.

	Company Operated		Other		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	38	34.1	9	6.8	47	40.9
Natural gas	515	515.0	—	—	515	515.0
Total	553	549.1	9	6.8	562	555.9

Drilling Activity

The number of wells drilled refers to the number of wells (holes) completed at any time during the fiscal years, regardless when drilling was initiated. The term “completion” refers to the installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry hole, to the reporting of abandonment to the appropriate agency. The following table sets forth our drilling activity for the last two years ended December 31, 2007 and 2006. The Company had several wells drilled but not yet completed at December 31, 2007 that are excluded from the following table. In the table, “gross” refers to the total wells in which we have a working interest and “net” refers to gross wells multiplied by our working interest therein.

	Year Ended December 31,			
	2007		2006	
	Gross	Net	Gross	Net
Exploratory Wells				
Productive	4	2.5	—	—
Nonproductive	—	—	—	—
Total	4	2.5	—	—
Development Wells				
Productive	—	—	1	1
Nonproductive	—	—	—	—
Total	—	—	1	1

Delivery Commitments

We are not obligated to provide a fixed and determinable quantity of oil or natural gas in the near future under existing contracts or agreements. Furthermore, during the last three years we had no significant delivery commitments.

(E) ***ENHANCED OIL RECOVERY***

A focus of the Company involves enhanced oil recovery (“EOR”). This refers to the recovery of oil that is left behind after primary recovery methods are either exhausted or no longer economical. The Company can utilize both conventional and non conventional methods to achieve EOR.

Primary production is the first oil out, the “easy” oil. Once a well has been drilled and completed in a hydrocarbon-bearing zone, the natural pressures at that depth may and often do cause the oil to flow through the rock or sand formation toward the lower pressure wellbore.

Secondary recovery methods are used when there is insufficient underground pressure to move the remaining oil. Water-flooding is one of the most common and efficient secondary recovery processes. Water is injected into the oil reservoir in certain wells in order to renew a part of the original reservoir energy. As this water is forced into the oil reservoir, it spreads out from the injection wells and pushes some of the remaining oil toward the producing wells. Eventually the water front will reach these producers and increasingly larger quantities of water will be produced with a corresponding decrease in the amount of oil. Other processes include stimulations by re-permeating through technologies for fracturing formations “fracing”, as well as lateral horizontal drilling. Management believes that in time and with prolonged deployment in a number of its wells, the lateral drilling technology available to Maxim will prove most efficient at the lowest cost. Tertiary recovery involves injecting other gases, such as carbon dioxide, to stimulate the flow of the oil and to produce remaining fluids.

EOR Technology Available to the Company

Lateral Horizontal Drilling (Water Jetting)

Utilizing existing drilled wells, the Lateral Horizontal Drilling Technology (“LHD Technology”) is a technique where the well bore casing is milled at different directions and at different levels in a “wheel and spoke” fashion and then fluid is jetted at high pressure through the formation. The jetted fluid can penetrate laterally for up to 300 feet in up to four directions at any given depth. LHD Technology can be conducted at a fraction of the time and cost of conventional drilling methods. The LHD Technology employs low volumes of water, is friendly to the environment, and no attendant mud pits or drilling fluids are required. The LHD Technology can be adapted for use on both new and existing wells, although the Company believes that it is most effective on formations with low production.

LHD Technology can provide the Company an alternative, non-traditional, method to recover oil and natural gas reserves that otherwise may have been beyond the reach of conventional technologies. LHD Technology can also be utilized for fracturing, water injection and acidizing intervals or water zones at a fraction of the time and cost of conventional methods.

Propellant Fracturing

In 2006, the Company began utilizing a fracturing technology that employs a propellant fracturing tool using solid propellant, referred to as "low order explosives" to generate high pressure gas at a rapid rate which can be tailored to formation characteristics. The technique is designed to create multiple fractures radiating more than 20 feet from the wellbore and avoids pulverizing and compacting the rock.

This propellant fracturing tool is compatible with both open and cased-hole completions. The tool is usually deployed by wireline or coiled tubing. Typically little or no cleanup is required, and the well can usually be put back on production soon after the stimulation, hence offering little "down" time.

(F) ***ORGANIZATION***

The company has set in place a corporate structure that organizes different functions and individual holdings in separate subsidiaries. In this way it can finitely address both budget and funding/reporting needs, while also limiting any unnecessary corporate exposure.

1) Maxim TEP Financial, LLC coordinates all Company funding and finance, as well as coordination and presentation of the Company to public markets

2) MTEP Land & Mineral Management, LLC oversees drilling and field enhancement operations within each of the Company's wholly owned subsidiaries:

A. Axiom TEP, LLC and Delhi Oil & Gas, LLC controlling the two Louisiana properties
B. Smackover Creek Energy, LLC and DC Operating Co., LLC for two Arkansas properties
C. HM Operating Company, LLC and MTEP Clovis (being formed) for two New Mexico acquisitions
D. Mud River Energy, LLC controlling the Company's Kentucky operations
E. Tiger Bend Gas Pipeline, LLC controlling the Company's Louisiana pipeline holdings
F. MTEP Technologies, LLC a technology holding firm for the non conventional Radial/Lateral Drilling Licensing, LLC (being formed) owned by the Company
G. Tiger Bend Drilling, LLC provides vertical well drilling services

The Board of Directors oversees the corporate activities, working in conjunction with the President/CEO and Management team.

Employees

At May 15, 2008, Maxim and its subsidiaries had a total of 17 full-time employees. There are six employees at the Company's corporate headquarters in The Woodlands, Texas. See "Item 6, Executive Compensation."

Trademarks and Other Intellectual Property

The Company purchased exclusive North American rights for a non-conventional lateral drilling technology invented by Carl Landers, a Director of the Company from inception. The patents comprising this lateral drilling technology are: US Patent Number 5,413,184 *Method and Apparatus for Horizontal Well Drilling* , issued May 9, 1995; US

Patent Number 5,853,056 *Method and Apparatus for Horizontal Well Drilling* , issued December 12, 1998; and US Patent Number 6,125,949 *Method and Apparatus for Horizontal Well Drilling* , issued October 3, 2000. There can be no assurance that these patents and the related technology will perform to the Company' expectations. Further, there can be no assurance that these patents and related technology do not infringe upon the intellectual property rights of others.

Distribution Methods

Each of our fields that produce oil distributes all of the oil that it produces through one purchaser for each field. We do not have a written agreement with some of these oil purchasers. These oil purchasers pick up oil from our tanks and pay us according to market prices at the time the oil is picked up at our tanks. There is significant demand for oil and there are several companies in our operating areas that purchase oil from small oil producers.

Each of our fields that produce natural gas distributes all of the natural gas that it produces through one purchaser for each field. We have distribution agreements with these natural gas purchasers that provide us a tap into a distribution line of a natural gas distribution company and to be paid for our natural gas at either a market price at the beginning of the month or market price at the time of delivery, less any transportation cost charged by the natural gas distribution company. These charges can range widely from 2 percent to 20 percent or more of the market value of the natural gas depending on the availability of competition and other factors. Due to the lack of available distribution lines on our South Belridge field, the operator has elected to sell the natural gas produced to a neighboring company to be used on their lease at a high discount.

Competitive Business Conditions

We encounter competition from other oil and natural gas companies in all areas of our operations. Because of record high prices for oil and natural gas, there are many companies competing for the leasehold rights to good oil and natural gas prospects. And, because so many companies are again exploring for oil and natural gas, there is often a shortage of equipment available to do drilling and workover projects. Many of our competitors are large, well-established companies that have been engaged in the oil and natural gas business for much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. We may not be able to conduct our operations, evaluate and select properties and consummate transactions successfully in this highly competitive environment.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Source and Availability of Raw Materials

We have no significant raw materials. However, we make use of numerous oil field service companies in the drilling and workover of wells. We currently operate in areas where there are numerous oil field service and drilling companies that are available to us.

Dependence on One or a Few Customers

There is a ready market for the sale of crude oil and natural gas. Each of our fields currently sells all of its oil production to one purchaser for each field and all of its natural gas production to one purchaser for each field. However, because alternate purchasers of oil and natural gas are readily available at similar prices, we believe that the loss of any of our purchasers would not have a material adverse effect on our financial results.

The Company sold oil and natural gas production representing more than 10% of its oil and natural gas revenues as follows:

	Year Ended December 31,	
	2007	**2006**
Interconn Resources, Inc. *(1)*	39%	51%
Lion Oil Trading & Transportation, Inc. *(1)*	17%	–
Plains Marketing, LP *(1)*	10%	–
Orchard Petroleum, Inc. *(2)*	32%	47%

(1) The Company does not have a formal purchase agreement with this customer, but sells production on a month-to-month basis at spot prices adjusted for field differentials.

(2) Orchard Petroleum, Inc is the operator of the Company's wells in California and sells production on the Company's behalf to Kern Oil & Refining, Co. and Aera Energy, LLC.

Periodic Reports and Available Information

We are filing this registration statement under Section 12(g) of the Securities Exchange Act of 1934. The effectiveness of this registration statement subjects us to the periodic reporting requirements imposed by Section 13(a) of the Securities Exchange Act.

We will electronically file with the Commission the following periodic reports:

- *Annual reports on Form 10-K;*
- *Quarterly reports on Form 10-Q;*
- *Periodic reports on Form 8-K;*
- *Annual proxy statements to be sent to our shareholders with the notices of our annual shareholders' meetings.*

In addition to the above reports to be filed with the Commission, we will prepare and send to our shareholders an annual report that will include audited consolidated financial statements.

The public may read and copy any materials we file with the Commission at the Commission's Public Reference Room at 100 F Street NE, Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the Commission at 1-800-SEC-0330. Also, the Commission maintains an Internet site (http://www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that electronically file reports with the Commission.

Government Regulations

Our facilities in the United States are subject to federal, state and local environmental laws and regulations. Compliance with these provisions has not had, and we do not expect such compliance to have, any material adverse effect upon our capital expenditures, net earnings or competitive position.

Regulation of transportation of oil

Sales of crude oil, condensate, natural gas and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, (“FERC”), regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines’ published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of transportation and sale of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act. The Decontrol Act removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC 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. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states on shore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which may increase our costs of getting gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. Such regulations govern conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, health and safety regulation

Our operations are subject to stringent and complex federal, state, local and provincial laws and regulations governing environmental protection, health and safety, including the discharge of materials into the environment. These laws and regulations may, among other things:

§ Require the acquisition of various permits before drilling commences;
§ Restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;
§ Limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
§ Requires remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of the material existing environmental, health and safety laws and regulations to which our business operations are subject.

Waste handling . The Resource Conservation and Recovery Act, or “RCRA”, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal 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 or natural gas are currently regulated under RCRA’s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act . The Comprehensive Environmental Response, Compensation and Liability Act, or “CERCLA”, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, in connection with the release of a hazardous substance into the environment. Persons potentially liable under CERCLA include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance to the site where the release occurred. 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, damages to natural resources and 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.

We own and lease, and may in the future operate, numerous properties that have been used for oil and natural gas exploitation and production for many years. Hazardous substances may have been released on, at or under the properties owned, leased or operated by us, or on, at or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been or are operated by third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances were not under our control. These properties and the substances disposed or released on, at or under them may be subject to CERCLA, RCRA and analogous state laws. In certain circumstances, we could be responsible for the removal of previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. In addition, federal and state trustees can also seek substantial compensation for damages to natural resources resulting from spills or releases.

Water discharges . The Federal Water Pollution Control Act, or the “Clean Water Act”, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act, or “SDWA”, and analogous state laws impose requirements relating to underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations relating to permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water.

Air emissions . The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and certain states have developed and continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources. 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 analogous state laws and regulations.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not acted upon recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations.

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 that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All exploration and production activities 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 on federal lands.

Health safety and disclosure regulation . We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the Emergency Planning and Community Right to Know Act and similar state statutes require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations.

We expect to incur capital and other expenditures related to environmental compliance. Although we believe that our compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operation.

ITEM 2. FINANCIAL INFORMATION

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our consolidated financial statements and the accompanying notes included elsewhere in this Registration Statement. Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations.

Going concern

As presented in the accompanying consolidated financial statements, the Company has incurred net losses of $29,985,540 and $36,822,509 during the years ended December 31, 2007 and 2006, respectively, and losses are expected to continue in the near term. Current liabilities exceeded current assets by $59,195,129 and $36,808,692 at December 31, 2007 and 2006, respectively, and the accumulated deficit is $89,244,111 and $59,258,571 at December 31, 2007 and 2006, respectively. Amounts outstanding and payable to creditors are in arrears and the Company is in negotiations with certain creditors to obtain extensions and settlements of outstanding amounts. The Company is currently in default on certain of its debt obligations and the Company has no future borrowings or funding sources available under existing financing arrangements. Management anticipates that significant additional capital expenditures will be necessary to develop the Company’s oil and natural gas properties, which consist primarily of proved reserves that are non-producing, before significant positive operating cash flows will be achieved.

Management's plans to alleviate these conditions include the renegotiation of certain trade payables, settlements of debt amounts with stock, deferral of certain scheduled payments, and sales of certain non-core properties, as considered necessary. In addition, management is pursuing business partnering arrangements for the acquisition and development of its properties as well as debt and equity funding through private placements. Without outside investment from the sale of equity securities, debt financing or partnering with other oil and natural gas companies, operating activities and overhead expenses will be reduced to a pace that available operating cash flows will support.

The accompanying consolidated financial statements are prepared as if the Company will continue as a going concern. The financial statements do not contain adjustments, including adjustments to recorded assets and liabilities, which might be necessary if the Company were unable to continue as a going concern.

General Overview

We are an independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties. Our areas of operation include California, Louisiana, Arkansas and Kentucky.

Over our first three years, we have emphasized the acquisition of properties that provided current production and upside potential through further development and the enhanced recovery through secondary/tertiary technology innovations. Our drilling and EOR activity is directed at infield development; specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and development allows us to direct our capital resources to what we believe to be the most advantageous investments that result in immediate cash-flow, reduced risk by using developmental drilling, and reserve value.

We target the purchase of operated and non-operated properties that should meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. We may sell properties when we believe that the sale price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Using that business model, we constantly look for drilling opportunities for new proved reserves and to develop proved undeveloped reserves on properties that provide low-risk, immediate revenue. In future years, the Company will strive to create a balance of near-term and long-term production, but for now our focus is on current and near-term production. We target the acquisition of properties with proved reserves that we can quickly develop and subsequently produce to help us meet our production goals.

At the inception of the Company, management understood that during the first years of the Phase One-Acquisitions Phase, the Company would report losses and increased expenses as a result of the overhead, financing costs, and initial drilling and the lack of oil and natural gas sales, or the limited sales in the case of the acquisition of fields that had some oil and natural gas production.

During 2006 and 2007, Maxim initiated its Phase Two, drilling program. This drilling program was originally aimed at increasing cash flow from a portion of the existing wells by laterally drilling them to stimulate additional production. From these drilling activities, anticipated production would provide additional cash flow that could be used for ongoing drilling of more wells. This plan includes enhancement and completion work on seven (of the thirteen) wells in Days Creek Field and completion of three remaining wells in Marion Field, as well as the drilling and completion of two wells at the Stephens Field.

Oil and Natural Gas Operations—The Company’s principal revenue stream is derived from the sale of oil and natural gas. For the sale of oil, the Company contracts with buyers and distributors who pick up the oil at our tank batteries for a spot price. The majority of the Company’s natural gas production is sold through a marketing company for a spot price. We deliver the gas to an interstate gas pipeline normally at pressures in excess of 600 psi. The quality of the gas stream is rated in British thermal units, (“Btu”) and must be pipeline quality. The spot price is adjusted for changes in Btus.

Drilling Revenues—Because of high prices for oil and natural gas, there are many companies exploring for oil and natural gas resulting in a shortage of equipment available to do drilling and workover projects. Accordingly, the Company formed Tiger Bend Drilling, LLC in early 2006 and purchased two used drilling rigs and then refurbished the rigs and trained crews. The Company’s direct drilling rig investments were intended to be an effective hedge to higher service costs and have a competitive advantage in making acquisitions and in developing the Company’s own leaseholds on a more timely and efficient basis. The Company needed rig availability that could be timed to its free cash flow for capital expenses. Working with a local drilling supervisor, the rigs drilled four new gas wells on our Marion field, followed by one contracted well in mid-2006. The Company decided that the carrying costs of the drilling rigs and equipment outweighed the benefits of ownership and rig availability. Therefore, in November 2006 the Company sold the drilling rigs and related equipment for $1,550,000 and recorded a loss on the sale of approximately $768,000. In 2007, the drilling subsidiary leased a rig and drilled two wells in which the Company had an interest. The drilling subsidiary currently has no activity.

Lateral Drilling License Fees, Royalties and Related Services—The Company purchased the master license for the Lander’s Horizontal Drilling Technology (“LHD Technology”), and later completed the acquisition by purchasing the patents from the inventor. The Company initially focused its attention on obtaining aging oil and natural gas properties and enhancing their performance through the use of this wholly-owned proprietary technology. As a new entity, the Company found little internal expertise or resources available to make meaningful improvements to the technology. The Company entered into a series of sublicensing agreements that were intended to fully commercialize the technology and focus on continuing improvements. Through its licensing program, the Company was able to generate needed cash flow from license fees and LHD Technology equipment sales. The Company entered into a contract with another company to jointly market and perform lateral drilling services. The in-house resources required to make the lateral drilling venture a success detracted from the development and operation of the oil and natural gas fields. The Company and its partner terminated the relationship in 2005. The Company wanted to demonstrate its faith in the technology and contracted one of its sub licensees to laterally jet four gas wells in the Marian field. During 2006, the Company determined that it would no longer actively market territorial exclusive licensees for the technology. Sub licensees with exclusive contracts were simply not performing to expected levels and faced no competition when armed with an exclusive license. With the reduction in sub licensing opportunities, the sale of rigs and downhole tools also decreased. In 2007, the Company entered into an agreement with a sub licensee to provide downhole tools, training and technology development for a percent of the gross receipts. Currently, the Company owns one coiled tubing unit designed for LHD Technology in wells less than 2,500 feet deep.

Revenue Recognition—The Company recognizes oil and natural gas revenues upon transfer of ownership of the product to the customer which occurs when (i) the product is physically received by the customer, (ii) an invoice is generated which evidences an arrangement between the customer and us, (iii) a fixed sales price has been included in such invoice and (iv) collection from such customer is probable. Volumes of oil and natural gas sold are not materially different than volumes produced.

The Company recognizes drilling revenues when services are performed and earned.

The Company recognizes revenue from issuing sublicenses for the right to use the Company's LHD Technology and from the sale of specifically constructed lateral drilling rigs and related rig service parts required by the licensees to utilize the LHD Technology. Revenue from license fees is recognized over the term of the license agreement. For license agreements entered into that have an indefinite term, revenue is earned and recorded at closing, subject to the credit worthiness of the licensee if credit terms are extended. License royalty revenue is recognized when licensees drill wells that utilize LHD Technology and a royalty is earned. Revenue generated from the sale of rigs and rig service parts is recognized upon delivery.

Commodity pricing risks—The Company's profitability is highly dependent on the prices of oil and natural gas. Commodity prices are outside of our control and historically have been and are expected to remain volatile. Commodity prices are affected by changes in market demands, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, natural gas liquids and crude oil prices, and therefore, cannot accurately predict revenues. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Operating cost controls—To maintain our competitive position, we must control our lease operating costs and other production costs. As reservoirs are depleted and production rates decline, per unit production costs will generally increase and affect our profitability and operating cash flows. Similar to capital expenditures, our ability to control operating costs can be affected when commodity prices rise significantly. Our production is focused in core areas of our operations where we can achieve economies of scale to assist our management of operating costs.

Capital investment discipline—Effectively deploying our very limited resources into capital projects is key to maintaining and growing future production and oil and natural gas reserves. Therefore, maintaining a disciplined approach to investing in capital projects is important to our profitability and financial condition. In addition, our ability to control capital expenditures can be affected by changes in commodity prices. During times of high commodity prices, drilling and related costs often escalate due to the effects of supply versus demand economics. One-hundred percent of our planned 2008 investment in capital projects is dedicated to a foundation of low-risk projects in the United States. By deploying our capital in this manner, we are able to consistently deliver cost-efficient drill-bit growth and provide a strong source of cash flow while balancing short-term and long-term growth targets.

Impairment of Oil and Natural Gas Properties— The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "*Accounting for the Impairment and Disposal of Long-Lived Assets*." Impairment of an individual producing oil and natural gas field is first determined by comparing the undiscounted future net cash flows associated with the proved property to the carry value of the underlying property. If the cost of the underlying property is in excess of the undiscounted future net cash flows the carrying cost of the impaired property is compared to the estimated fair value and the difference is recorded as in impairment loss. Management's estimate of fair value takes into account many factors such as the present value discount rate, pricing, and when appropriate possible and probable reserves when justified by economic conditions and actual or planned drilling or other development activities. For unevaluated property costs, management reviews these investments for impairment on a property by property basis at each reporting period or if a triggering event should occur that may suggest that an impairment may be required.

Accordingly, the Company recorded $7,195,367 and $4,843,688 as impairment of proved oil and natural gas properties and related equipment on the South Belridge Field during the years ended December 31, 2007 and 2006, respectively. Using the prices in effect and estimated proved reserves on December 31, 2006, the write-down would have been approximately $5.3 million, or approximately $0.5 million larger, had we not taken into account subsequent improvements in oil and natural gas prices. Because of the volatility of oil and natural gas prices, no assurance can be given that we will not experience additional write-downs in future periods. The Company recorded $250,000 as impairment of unproved oil and natural gas properties at December 31, 2007 as it was decided to not pursue prospects in the Kansas property thus we allowed those leases to expire. There was no impairment of unproved properties required at December 31, 2006.

Alternative Investment Market Fund Raising Activities—The Company incurred several pre-initial public offering costs over a one-year period straddling the 2005-2006 fiscal years as the Company investigated and attempted placement on the Alternative Investment Market ("AIM") of the London Stock Exchange. AIM fund raising activities for 2006 were $2,666,587. AIM fund raising activities in 2006 mostly consisted of $1,271,183 of consulting services, of which $1,162,500 was recorded as the value of 1,550,000 shares of common stock issued for services. Costs of $680,274 in 2006 were incurred for two separate law firms and public accounting firms, one in the United States and one in the United Kingdom. Costs of $368,908 in 2006 were also incurred to secure a third party engineering assessment of the Company's US based oil and natural gas assets that would not have been required other than for this offering. In addition, these costs include $345,060 in 2006 of incremental increased travel and related expenses in opening and maintaining offices in London. The Company terminated its association with the London based broker for listing on the AIM when it became apparent that funding could not be secured under favorable terms and that tax issues would prove unattractive to all existing shareholders.

Equity, Debt and Asset Based Financing — From inception, the Company has sought investment from accredited investors and through the issuance of debt instruments. The Company has also utilized the offer to investors of net revenue interests ("NRI"), overriding revenue interests ("ORRI") and working interest in individual wellbores as a means of securing financing for both corporate and field operations.

Prior to 2006, the Company has raised a total of $7,936,280 in funds from the sale of shares of common stock at $0.75 per share, and $17,265,375 from debt and revenue-sharing debt instruments.

In 2006, the Company sold 6,760,865 shares of common stock at $0.75 per share raising $5,050,650. Additionally, the Company raised $37,408,772 in debt from a private European equity firm, the Greater Europe Fund Limited and used these funds to satisfy the Company's contractual obligations to Orchard Petroleum on the South Belridge California property, as well as acquire the Delhi Field Unit in Louisiana and the Stephens Field in Arkansas. The Company also raised $566,667 of funding through the issuance of debt with three parties in consideration for NRI in wells in Louisiana; $1,450,000 from the Riderwood Group for the issuance of debt in our California property which all converted to equity; $6,000,000 in debt issued to the sellers to acquire Days Creek; and an additional draw down of allocated work-over funds available from the asset-based financing of the Marion Field in the amount of $222,000. The Company issued debt to a Board member for the purchase of intellectual property in the amount of $3,650,000. Additionally, other funds were raised in 2006 consisting of the sale of two drilling rigs raising $1,550,000, and all of these those funds were used in the operation of the Company and its newly acquired fields.

In 2007, the Company sold 4,188,465 shares of common stock to investors at $0.75 per share raising $3,141,349. Additionally, the Company raised $1,582,333 through debt financing from its Executive Officers and Directors. In May 2007, the Company closed on the sale of certain wellbores, representing a portion of the Delhi Field Unit for cash proceed of $2,500,000. All funds raised in 2007 were used to support operations and continue our Phase Two drilling and well enhancement program.

Results of Operations

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Oil and Natural Gas Revenues . Oil and natural gas revenues for 2007 and 2006 were $3,536,231 and $2,979,219, respectively, an increase of 18.7%. This increase was attributed to the acquisition of the Days Creek Field and the Delhi Field, which had revenues for 2007 of $565,774 and $360,860, respectively. This increase was also due to revenues from wells drilled in 2007 in the Belton Field and the Stephens Field of $59,760 and $44,613, respectively. These increases were offset by a decrease in the Marion Field revenues of $152,330 due to average natural gas price decrease, and by a decrease in the South Belridge Field revenues of $278,917 due to both oil and natural gas production declines year over year.

Drilling Revenues. Drilling revenues for 2007 and 2006 were $329,018 and $66,344, respectively. In fourth quarter 2006 the Company's Tiger Bend Drilling, LLC subsidiary drilled one shallow well for a third party. The Company's Tiger Bend Drilling, LLC subsidiary drilled two wells in the Stephens field, of which the Company holds a 24% working interest, during 2007 and the $329,018 in drilling revenues corresponds to the billings to the other working interest partners for drilling services.

License Fees, Royalties & Related Services. License fees, royalties and related services for 2007 and 2006 were $257,500 and $377,500, respectively, a decrease of $120,000. Licensing revenues increased from $125,500 for 2006 to $188,000 for 2007. These fees were associated with the granting of sectional and regional licensing of the Company's proprietary lateral drilling technology. The Company believes that licensing revenues will decrease in the near future as the Company is not currently actively marketing sublicenses of its technology in favor of concentrating on internal field development, but believe that with ongoing in-house usage of the technology, there will be future opportunities to market the technology based on results documented by the Company. This increase was offset by a decrease in the sale of lateral drilling technology equipment from $252,000 for 2006 to $42,000 for 2007.

Production and Lease Operating Expenses. Production and lease operating expenses for 2007 and 2006 were $2,992,812 and $1,725,211, respectively, an increase of 73.5%. This increase was attributed to the acquisition of the Days Creek Field and the Delhi Field, which had a full twelve months of operations in 2007, for an increase of operating expenses of $534,092 and $501,911, respectively. These expenses included several initial well workovers, repair and maintenance of the existing infrastructure and equipment. Of the $231,598 remaining increase in operating expenses, $155,717 was due to two more wells on production for the full 2007 period in the South Belridge Field and $59,828 was due to increased operating costs in the Belton Field due to several new wells drilled in 2007.

Drilling Operating Expenses. Drilling operating expenses for 2007 and 2006 were $1,059,168 and $324,628, respectively. During the 2007 period the Company incurred $538,160 in subcontract labor, $67,620 in per diem costs, and $399,370 in rig fuel, maintenance and other operational costs to drill two deep wells in Arkansas in which the Company had a drill and completion 37.33% working interest and one well in Arkansas in which the Company had a drill and completion 100.0% working interest. The Company also incurred $400,000 during 2007 to lease a big drilling rig to use for these deep wells. This was an incremental cost to the prior year when the Company had owned its own drilling rigs. The Company spent 45 billable days drilling these three wells and capitalized $345,983 of the costs incurred to oil and gas properties as intangible drilling costs. The Company incurred two weeks of downtime because of drill stem reconditioning and mud pump repairs, and attributed approximately $105,000 of the costs incurred as expenses of keeping crews and the drilling rig active to hold circulation in the well. These costs could not be billed to working interest owners of the property and were recorded 100% as expense to the Company.

During the 2006 period the Company incurred $374,336 in subcontract labor, $31,918 in per diem costs, and $76,624 in rig fuel, maintenance and other operational costs to drill 4 shallow wells in Louisiana in which the Company had a 100% working interest and one shallow well in Louisiana for a third party. The Company spent 27 days drilling its own four shallow wells and capitalized $158,250 of the costs incurred to oil and gas properties as intangible drilling costs. The Company believes that $119,150 of these 2006 costs were attributed to start up costs of the drilling subsidiary company to train crews and repair the drilling rig in preparation for drilling work and were therefore expensed.

Costs Attributable to License Fees and Related Services. License fees and related service costs for 2007 and 2006 were $178,820 and $616,496, respectively, a decrease of 71.0%. The majority of the decrease is due to 2006 including $250,000 in licensing fees to the original technology owner during patent purchase negotiations. The decrease is also due to a $126,652 decrease in the cost basis of the lateral drilling technology equipment with less equipment sold in the 2007 period and is consistent with the decrease in related revenues. In addition the Company has decided to decrease this line of service, thus decreasing marketing and operational related expenses in 2007.

Exploration Costs. Exploration costs for 2007 and 2006 were $458,650 and $882,884, respectively, a decrease of $424,234 or 48.1%. This decrease was due to management's election to curtail exploration activities due to the lack of available capital resources.

Revenue Sharing Royalties. Revenue sharing royalties for 2007 and 2006 were $165,418 and $389,757, respectively, a decrease of $224,339 or 57.6%. This decrease was due to production declines in the South Belridge Field resulting in lower overall net profits subject to distribution.

Depletion, Depreciation and Amortization. Depletion, depreciation, and amortization for 2007 and 2006 were $2,798,758 and $1,760,401, respectively, an increase of 59.0%. The increase was due to; the addition of $508,929 of amortization expense related to the purchased technology patent which was acquired in September 2006, the addition of $248,609 of depletion and depreciation from the Days Creek Field and Delhi Field acquisitions, the increase in depletion and depreciation of $129,439 from two new wells put on production in mid-2006 in the South Belridge Field, and the increase of $162,988 from the Marion Field due to a combination of two new wells on production, a downward revision in the depletable reserve basis and current year capital additions.

Impairment of Oil and Natural Gas Properties . Impairment of oil and natural gas properties for 2007 and 2006 was $7,445,367 and $4,843,688, respectively. Management performed its impairment evaluation of its long lived assets and determined that the South Belridge Field required an impairment charge of $7,195,367 and $4,843,688 in 2007 and 2006, respectively, due to the future cash flows from the Company's interest in this field not being able to cover the cost basis of this property. The Company decided in 2007 not to pursue any prospects on the Medicine Lodge, Kansas property and has allowed all those leases to expire. Accordingly, the Company has recorded an impairment of $250,000 in 2007.

Impairment of Investment . Impairment of investment for 2007 and 2006 was $1,365,712 and $179,400, respectively. The majority of the 2007 impairment was attributed by the Company's decision not to go forward with the purchase of a fracturing technology that was initiated in 2006. Having this technology available to the Company's field teams is a major benefit in enhancing wells at a lower cost. This was the initial reason that the Company believed that owning the technology could provide additional cash flow as more service companies employed the technology worldwide. However, after a more profound analysis as to the cost-benefit of owning the technology as opposed to its standard operational use, and the need for significant funds to meet the Company's Phase One plans and operational overhead, management determined that ownership of this intangible asset could not be fully attained without impairing the execution of the Company's business plan. Management chose to stay focused singularly on its drilling plan and chose not to conclude the purchase, recognizing a $1,065,712 one-time loss representing advance payments towards the purchase price that were not refundable. In 2007 the Company also recorded an impairment of $225,000 to write-off costs spent on purchasing a pipeline in Kentucky that was abandoned in December 2007, and an impairment of $75,000 to write-off non-refundable costs spent pursuing the purchase of a third party's sub-license of the LHD Technology, which was also abandoned in 2007.

Penalty for Late Payments to Operator . The Company incurred late payment penalty fees to the operator of the South Belridge Field for fiscal year 2006 of $2,152,501. The Company made cash payments totaling $1,152,501 and issued 1,333,333 shares of common stock valued at approximately $1,000,000 to the operator as "late fees." The South Belridge Field has leasehold requirements of drilling 10 wells per year. Under that term of our JOA with the operator we were to provide 100% of the capital costs up to a certain limit, but when the Company could not meet cash call demands the operator had to fund these capital costs. When the Company became able to fund these commitments, the operator charged the Company a fee for their carrying cost of capital and a penalty for buying into wells already drilled.

Alternative Investment Market Fund Raising Activities. The Company incurred several pre-initial public offering costs over a one-year period straddling the 2005-2006 fiscal years as the Company investigated and attempted placement on the Alternative Investment Market ("AIM") of the London Stock Exchange. AIM fund raising activities for 2006 were $2,666,587. AIM fund raising activities in 2006 mostly consisted of $1,271,183 of consulting services, of which $1,162,500 was recorded as the value of 1,550,000 shares of common stock issued for services. Costs of $680,274 in 2006 were incurred for two separate law firms and public accounting firms, one in the United States and one in the United Kingdom. Costs of $368,908 in 2006 were also incurred to secure a third party engineering assessment of the Company's US based assets that would not have been required other than for this offering. In addition, these costs include $345,060 in 2006 of incremental increased travel and related expenses in opening and maintaining offices in London. The Company terminated its association with the London based broker for listing on the AIM when it became apparent that funding could not be secured under favorable terms and that tax issues would prove unattractive to all existing shareholders.

General and Administrative Expenses. General and administrative expenses for 2007 and 2006 were $8,644,418 and $8,157,225, respectively. This net increase of $487,193 or 6.0% was the result of several offsetting factors. The major change came from payroll and associated expenses increasing by $831,726, primarily due to the 2007 year including 2.5 million shares of common stock valued at $1,875,000 issued to the former CEO pursuant to his employment agreement. This increase was offset by the 2006 year including accrued bonuses to three executive officers of $700,000. The majority of these bonus payments were deferred by the executives to assist the Company with its cash flow requirements. In addition, the 2006 year included a $306,000 payment and 250,000 stock options valued at $102,500 to a former director pursuant to a Separation Agreement. Payroll and associated expenses also increased over the 2006 year with the increase in employees from the Company hiring some of the consultants it had previously been contracting.

The change in general and administrative expenses was also due to legal and professional expenses increasing by $339,168 in 2007, primarily relating to the increased attorney fees and audit fees as the Company has prepared to become a public filer with the SEC. This was offset by a decrease in consulting services of $495,570 which was mainly due to three consultants becoming employees and the postponement of engineering services for the fields in 2007 that were incurred in the comparable 2006 year. In addition, travel expenses declined by $490,331 due to the 2006 year including significant travel by management for fund raising purposes and due diligence on several property acquisitions.

Warrant Inducement Expense . During 2006, in its effort to raise capital the Company issued warrants with an original exercise price of $0.75 per share, as investment incentives in raising over $17,000,000 in debt and equity funding. As a further incentive and to reduce the outstanding number of warrants, the Company offered these warrant holders the option of exchanging their warrants and issued four shares of common stock in exchange for every five warrants returned. In so doing the Company issued a total of 18,305,545 shares of common stock in the exchange, thereby eliminating approximately 22,915,255 warrants and the Company recorded $10,934,480 in other expenses as non-cash warrant inducement expense to account for the fair market value of this exchange.

Interest Expense, net . Interest expense, net for 2007 and 2006 was $8,847,238 and $4,468,373, respectively. Interest expense related to debt increased $4,793,442 as the average outstanding balance increased over 2006 substantially from the full year outstanding of approximately $37,400,000 debt facility provided by Maxim TEP, Plc., a UK non-affiliated company to Maxim TEP, Inc., and controlled by the Greater Europe Fund Limited (“GEF”). The Company has subsequently repaid this debt and its corresponding accrued interest through the sale of the South Belridge Field and issuance of 21,700,000 shares of common stock in April 2008. Interest expense increased by $333,333 related to interest from stock put options issued in 2007 and effectively increased by $99,860 from a reduction in capitalized interest. These increases were offset by a decrease in the amortization of deferred financing costs of $683,127 and the amortization of debt discount of $208,209.

Income Taxes . There is no provision for income tax recorded for either 2007 or 2006 due to operating losses in both years. The Company has available Federal income tax net operating loss (“NOL”) carry forwards of approximately $79.8 million at December 31, 2007. The Company’s NOL generally begins to expire in 2026. The Company recognizes the tax benefit of NOL carry forwards as assets to the extent that Management believes that the realization of the NOL carry forward is more likely than not. The realization of future tax benefits is dependent on the Company’s ability to generate taxable income within the carry forward period. This valuation allowance is provided for all deferred tax assets.

Net Loss . The Company incurred a loss from operations for the year ended December 31, 2007 of $29,985,540 specifically due to reasons discussed above.

Liquidity and Capital Resources

Years Ended December 31, 2007 Compared to the Year Ended December 31, 2006

At December 31, 2007, the Company had a working capital deficit of $59,195,129 consisting primarily of $48,969,797 in current debt, and $12,552,264 in accounts payable and accrued liabilities, offset by $166,412 of cash, $1,912,131 in receivables, $88,868 in inventories, and $159,521 of prepaid expenses and other current assets.

Net cash used in operating activities totaled $7,444,874 and $11,565,942 for 2007 and 2006, respectively. Net cash used in operating activities for 2007 consists primarily of the net loss of $29,985,540 and the increase in receivables of $1,107,493, offset by the net increase in accounts payable and accrued liabilities of $7,689,818, and by several non-cash charges including an impairment of oil and natural gas properties of $7,445,367, stock based compensation valued at $2,539,140, depletion, depreciation and amortization of $2,798,758, amortization of deferred financing costs of $1,332,482, and an impairment of investment of $1,365,712. The reduction in cash used in operating activities in 2007 as compared to 2006 was primarily due to the increase in revenues, the increase in common stock used to pay for services instead of cash, and the reduction in cash used with the significant increase in accounts payable and accrued liabilities.

Net cash provided by investing activities totaled $936,094 for 2007, compared to net cash used in investing activities of $26,076,315 for 2006. Net cash provided by investing activities for 2007 consists primarily of cash proceeds received of $2,250,000 from the sale of certain wells in the Delhi Field, cash proceeds of $620,000 from the sale of net revenue interests in several fields, and cash proceeds of $500,000 from the disposal of its investment in a fracturing technology. These 2007 cash inflows were offset by capital expenditures for oil and natural gas properties of $7,417,866, netted against a change in oil and natural gas property accrual and prepayments applied to those capital expenditures of $5,265,652. The change in cash provided by (used in) investing activities in 2007 as compared to 2006 was primarily due to the 2006 year including capital expenditures for oil and natural gas properties of $7,669,068, capital expenditures for property and equipment of $2,254,380, investments in a fracturing technology business of $1,535,712, and $8,987,721 of payments to the South Belridge Field operator for 2005 capital additions and a prepayment on 2007 capital additions to satisfy our promote funding commitment, offset by proceeds from sale of assets of $1,558,829, primarily from the sale of two drilling rigs and related equipment.

Net cash provided by financing activities totaled $3,709,299 and $40,458,607 for 2007 and 2006, respectively. Net cash provided by financing activities for 2007 consists primarily of proceeds from the sale of common stock and treasury stock, net of offering costs, of $3,385,349, and proceeds from new borrowings of $1,582,333, offset by payments on notes payable of $1,106,623. The reduction in cash provided by financing activities in 2007 as compared to 2006 was primarily due to the $37,400,000 borrowed from GEF. Net cash provided by financing activities for 2006 consists primarily of proceeds from new borrowings of $39,739,244 and proceeds from the sale of common stock of $5,050,650, offset by payment of financing costs of $2,723,619 and payments on notes payable of $1,357,668.

While the company is actively seeking additional funding sources, no future borrowing or funding sources are available under existing financing arrangements.

Off Balance Sheet Arrangements

ORRI Arrangements. Since inception, the Company has raised funds to acquire oil fields, and fund drilling costs and general working capital requirements, through the issuance and sale of debt and equity instruments as well as from the sale of various assets, including the sale and issuance of overriding royalty interests ("ORRI") and revenue sharing agreements. The Company, based on its short term and long term funding needs, analyzes specific fields and the development requirements of the fields and, applying a cost benefit analysis, determines in which fields ORRI's can be sold and the amount of the ORRI's that can be sold. Senior management and field staff are involved in this analysis. Management then seeks approval from the Company's Board of Directors prior to selling an ORRI or entering into a revenue sharing agreement. In certain cases, the Company reserves the right to repurchase certain ORRI's in the future.

The following table summarizes the 8/8ths royalty interests ("RI") and ORRIs assumed and issued by the Company as of December 31, 2007.

Investor Name	**Date Issued**	**South Belridge Field (CA)**	**Days Creek Field (AR)**	**Stephens Field (AR)**	**Belton Field (KY)**	**Marion Field (LA)**	**Delhi Field (LA)**	**Hospah Field (NM)**
RI and ORRI assumed in acquisition of property		25.00%	25.00%	25.00%	6.25%	23.00 %*(a)*	12.83%	
Oladipo Aluko	01/01/07		1.00%	1.00%			1.00%	
Greathouse Well Services, Inc.	01/01/07				3.13% (7) wells			
Robert L. Newton	01/01/07				4.00%			
Robert L. Newton	01/01/07				3.50 (3% wells)			
Robert L. Newton	09/01/07							10.0%
Robert L. Newton	12/01/07		1.50%					
Robert L. Newton	12/01/07			10.00 (1 well %)				
Jon Peddie	03/01/07					25.00 (1% well)		
Harvey Pensack	12/01/07		1.00%					
Harvey Pensack	12/01/07					8.50 (1% well)		
Stephan Baden	03/01/07					25.00 (1% well)		
Frank Stack	01/01/07				3.50 (3% wells)			
Frank Stack	01/01/07				4.00%			
Frank Stack	12/01/07		1.50%					
Michael Walsh	12/01/07		1.00%					

(a) Estimated average for the 499 wells acquired.

On the Belton Field in Kentucky, the Company assumed an ORRI to Advanced Methane Recovery (6.25%) that was originally in place upon the property's purchase and granted a 4% ORRI to both Robert L. Newton and Frank Stack (on conversion of their 15% working interest from the Delhi property to this ORRI); and a 3.5% ORRI to both Robert L. Newton and Frank Stack, for additional cash infusions. A 3.125% ORRI was given to Greathouse Well Services, Inc. in each well drilled as supervised by them while under contract with the Company.

The Company issued an ORRI out of the Delhi, Days Creek and Stephens Field properties, granting a one percent (1%) ORRI interest out of each property to the Company's reserve engineer in lieu of billings for certain engineering services related to these properties.

In Louisiana, on one well (McDermott Estate No. 5) the Company issued an 8.5% ORRI to Harvey Pensack; a 25% ORRI to Jon Peddie; and a 25% ORRI to Stephan Baden, as an incentive for them to loan the Company a total of $566,667.

To fund working capital needs, the Company sold a 1% ORRI to Board member Harvey Pensack on Days Creek, and sold an additional ORRI in this field to: Robert L. Newton 1.5%; Frank Stack 1.5%; and Michael Walsh 1% for cash consideration of $100,000 for every one percent (1%) ORRI or a corresponding equal percentage based on the consideration received.

The Jones #1 well is an isolated well next to the Stephens field that was purchased by the Company with partial financing from Mr. Newton who received a 10% ORRI on this well in consideration of his $50,000 investment.

During 2007, the Company sold a 10% ORRI in its Hospah leases for $70,000.

Net Revenue Interests . From time to time a Revenue Sharing Agreement ("RSA") may be granted by the Company out of its existing working interest in oil and natural gas properties. These RSAs are calculated as a percentage of the Company's interest in an oil or natural gas property after lease operating expenses.

The following table summarizes issued Revenue Sharing Agreements and amounts earned under those agreements during 2007 and 2006.

Plan	Interest	2007	2006
$4M Net Distribution *(1)*			
Unrelated parties	9.00%	$ 11,490	$ 14,513
Related parties	28.00%	35,746	45,151
SB & Belton Field RSA *(2)*			
Unrelated parties	5.36%	17,283	27,626
Related parties	14.64%	47,206	75,455
SB 7 Well Program *(3)*			
Unrelated parties	4.78%	3,685	19,620
Related parties	–%	–	–
Marion Field RSA *(4)*			
Unrelated parties	0.20%	–	141
Related parties	1.20%	–	845
Total		$ 115,410	$ 183,351

(1) $4M Net Distribution provides participants a percentage of the first $4,000,000 per year of the Company's net operating revenue. The net operating revenue subject to the net revenue sharing arrangement declines by 2.5% per annum beginning January 1, 2008 and terminates in 40 years.

(2) SB & Belton Field RSA provides participants a net profits interest in the Company's South Belridge Field and the original 3,008 acre lease of the Company's Belton Field.

(3) SB 7 Well Program provides participants a net profits interest in seven certain wells of the Company's South Belridge Field.

(4) Marion Field RSA provides participants a net profits interest in the Company's Marion Field.

Financing Arrangements

The Company continues to have strong cash needs to fund its drilling program and capital expenditures, as well as working capital. The Company is projecting a drilling and development budget of $12.4 million dollars for 2008. As part of its Phase Two, it will be necessary to raise additional capital to support current operations as well as needing capital for continued drilling and workovers to further develop the Company's fields. Additionally, the Company will need working capital of approximately $6 million to pay third party engineers, subcontractors, and professional service providers, together with general overhead for 2008. While there are no guarantees that it will be successful, the Company is currently in negotiations to acquire a portion of such funding from financial institutions and accredited investors. The Company is currently in default on certain of its debt obligations and the Company has no future borrowings or funding sources available under existing financing arrangements. If the Company is not successful in securing its 2008 funding for a drilling and development budget, some of the Company's leases might be lost (see "Description of Fields" on Page 3) as well as the company may have to seek legal protection from creditors to protect its assets and assume additional losses in the process which at this point are difficult to forecast.

The Company's ability to obtain additional financing will be subject to a variety of uncertainties. The inability to raise additional funds on terms favorable to the Company could have a material adverse affect on its business, its financial condition and the results of its operations. If it were unable to obtain additional capital when required, the Company would be forced to make the necessary decisions to scale back operations and planned expenditures that would aversely affect its growth. There is no assurance that the current operating plan and growth strategy will be successful or that the Company will be able to complete its business plan's goals, and thus possibly affecting the Company's revenues and assets.

Production Payment Facility – Marion, Louisiana

During 2005, the Company entered into a production payment payable with a financial institution that provided for total borrowings up to $6,802,000. During 2005 and 2006, $6,275,000 and $220,000 was funded respectively. Of the proceeds received in 2005, $6,250,000 was used to acquire all the rights, title and interest in leases covering approximately 21,500 acres and 500 wellbores in the Monroe Gas Rock Field in Union Parrish, Louisiana (The Marion Field). Principal and interest will be paid out of production from the underlying property equal to 56% of the total revenues produced until an 18% internal rate of return is achieved. This production payment is secured by the Marion Field leases. During 2007 and 2006, production payments made to the financial institution were not sufficient to meet their internal rate of return of 18%. Therefore the outstanding balance of production payment payable was increased to accrue for the unpaid interest expense. At December 31, 2007, the Company has a total balance due of principal and interest to the financial institution of $6,877,945.

The Company has finalized its negotiations with BlueRock Energy Capital, Ltd ("BlueRock") to restructure its monthly production payment facility on its Marion Field. The negotiations call for a reduction of the interest rate from its current 18% to 8% and to give back to the Company up to $25,000 of its production payment so that the field would be cash flow positive. The Company's obligations under these new terms would be to seek refinancing of the production payment payable or the outright purchase of the production payable by no later than the anniversary of the agreement, should the Company not meet this obligation, BlueRock has the option of taking back the field in full payment of the production payment payable or revert back to the previous terms under the existing agreement.

Convertible Note By Owner Financing – Days Creek

During November 2006, the Company entered into three notes payable totaling $6 million, bearing interest at the rate of 10%, and maturing October 31, 2007, secured by the leases in the Days Creek Field. These notes payable are convertible into shares of the Company's common stock at an exchange rate of $0.75 per share. If the note holders exercise their right to convert into the Company's common stock, the Company will issue 8,000,000 shares of common stock. The notes payable are collateralized by the Company's oil and gas property in the Days Creek Field and they provide for default interest at 15%. The Company has extended the maturity date of these notes payable to April 30, 2008. The company has an executed debt facility term sheet and is in the later stages of the due diligence process with an financial company for development, refinancing and acquisition funding, of which a portion of the proceeds are for the payment of the three notes payable totaling $6 million. The notes have been verbally extended to the date this funding goes forward and the proceeds are released, but in lieu of an executed agreement they are technically in default.

Lease Option Arrangements (Kentucky & New Mexico)

The Company entered into lease option arrangements in the State of Kentucky to acquire additional property bordering, or adjacent to, it's existing acreage of approximately 3,008 acres. Management has leased an additional 6,317 acres and believes that it has the potential to acquire an additional 11,855 acres or more, whose acquisition would add the potential for substantially more drilling sites. Similarly, Management believes that its field acquisition activities in New Mexico of a 2,080 acre parcel, will also offer a substantial number of potential drilling sites.

South Belridge Field, Greater European Fund, Orchard Petroleum

In January 2005, the Company negotiated a joint operating agreement to acquire 960 acres in the South Belridge property in Kern County California to partner with Orchard Petroleum, Inc., an Australian-listed public company that would serve as operator since Orchard was already bonded to be an operator in the state of California. Maxim would have a 75% working interest of Orchard's 75% working interest on the first phase of drilling as long as the Company tendered a promotion fee of $28.5 million. Maxim and Orchard would split operational costs 75:25 on this property, with the 25% balance held by the property owners. In an effort to raise funds in support of the ongoing California commitment Maxim secured funding from the Greater Europe Fund Limited ("GEF"), a private equity firm headquartered in Frankfurt. The Company's loan facility with GEF and its affiliates provides for aggregate borrowings of $41.0 million, of which GEF lent a total of approximately $37.4 million. At December 31, 2007 the Company was in default on these notes payable but was in negotiations with the lender to repay this debt by selling a property.

During April 2008, the Company sold its South Belridge Field in a three party transaction that involved Mercuria Partners, a majority shareholder in Orchard Petroleum, and Maxim TEP PLC as an all inclusive deal to eliminate all debt, joint interest rights and obligations amongst all three parties, for a cash consideration of $35,846,346 and 21,700,000 shares of common stock in the Company to be issued to Maxim TEP PLC. With this cash and stock consideration, the Company will eliminate $37,408,772 in current note payable and approximately $6,100,000 in interest payable. Also, it will write down its net oil and gas assets by approximately $4,700,000. At the culmination of this transaction, the Company will have no further interest, rights or obligations in the South Belridge Field and will have satisfied in full all debt, interests and other obligations owed to Maxim TEP, PLC and its parent, the Greater European Fund, as well as any interest, rights or obligations under the Joint Venture agreement with Orchard Petroleum.

The fact that the Company is in default in some of its debt obligations could have a material adverse affect on its business, its financial condition and the results of its operations and put in question the Company's ability to move forward as a going concern.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases (decreases), there could be a corresponding increase (decrease) in the operating cost that we are required to bear for operations, as well as an increase (decrease) in revenues. Inflation has had a minimal effect on the operating activities of the Company.

Recently Issued Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, " *Fair Value Measurements*". This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements, where fair value has been determined to be the relevant measurement attribute. This statement is effective for financial statements of fiscal years beginning after November 15, 2007. The Company does not expect a material impact from SFAS No. 157 on its consolidated financial statements.

In February 2007, the FASB issued SFAS No. 159, " *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FASB Statement No. 115* ." The new standard permits an entity to make an irrevocable election to measure most financial assets and financial liabilities at fair value. The fair value option may be elected on an instrument-by-instrument basis, with a few exceptions, as long as it is applied to the instrument in its entirety. Changes in fair value would be recorded in income. SFAS No. 159 establishes presentation and disclosure requirements intended to help financial statement users understand the effect of the entity's election on earnings. SFAS

No. 159 is effective as of the beginning of the first fiscal year beginning after November 15, 2007. The Company does not expect a material impact from SFAS No. 159 on its consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), " *Business Combinations*" ("SFAS No. 141(R)"). SFAS No. 141(R) establishes principles and requirements to recognize the assets acquired and liabilities assumed in an acquisition transaction and determines what information to disclose to investors regarding the business combination. SFAS No. 141(R) is effective for business combinations for which the acquisition date is on or after the beginning of the first annual period beginning after December 15, 2008.

In December 2007, the FASB issued SFAS No. 160, " *Non-controlling Interests in Consolidated Financial Statement—amendments of ARB No. 51."* SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. The statement also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding non-controlling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. The Company currently has no subsidiary subject to this standard and does not expect a material impact from SFAS No. 160 on its consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, " *Disclosures about Derivative Instruments and Hedging Activities*". SFAS 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand their effects on an entity's financial position, financial performance, and cash flows. The provisions of SFAS 161 are effective for the fiscal years and interim periods beginning after November 15, 2008. The Company is currently evaluating the impact of adopting SFAS 161 on its consolidated financial statement disclosures.

On May 9, 2008 the FASB issued FASB Staff Position APB 14-1, " *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)*". APB 14-1 requires the issuer to separately account for the liability and equity components of convertible debt instruments in a manner that reflects the issuer's nonconvertible debt borrowing rate. The guidance will result in companies recognizing higher interest expense in the statement of operations due to amortization of the discount that results from separating the liability and equity components. APB 14-1 will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The Company is currently evaluating the impact of adopting APB 14-1 on it consolidated financial statements.

Recently Adopted Accounting Pronouncements

During September 2006, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109*," ("FIN 48") which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. Under FIN 48, the Company is required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The adoption of FIN 48 did not have a material effect on the Company's consolidated financial position or results of operations.

Summary of Critical Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect 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 periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of proved and unproved properties, future income taxes and related assets and liabilities, the fair value of various common stock, warrants and option transactions, and contingencies. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the calculation of impairment, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data, the engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

These significant estimates are based on current assumptions that may be materially effected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the fair value of the Company's common stock and corresponding volatility, and the Company's ability to generate future taxable income. Future changes to these assumptions may affect these significant estimates materially in the near term.

Oil and Natural Gas Properties

We account for investments in natural gas and oil properties using the successful efforts method of accounting. Under this method of accounting, only successful exploration costs that directly result in the discovery of proved reserves are capitalized. Unsuccessful exploration costs that do not result in an asset with future economic benefit are expensed. All development costs are capitalized because the purpose of development activities is considered to be building a producing system of wells, and related equipment facilities, rather than searching for oil and gas. Items charged to expense generally include geological and geophysical costs. Capitalized costs of proved properties are depleted on a field-by-field (Common Reservoir) basis using the units-of-production method based upon proved, producing oil and natural gas reserves.

The net capitalized costs of proved oil and natural gas properties are subject to an impairment test based on the undiscounted future net reserves from proved oil and natural gas reserves based on current economic and operating conditions. Impairment of an individual producing oil and natural gas field is first determined by comparing the undiscounted future net cash flows associated with the proved property to the carry value of the underlying property. If the cost of the underlying property is in excess of the undiscounted future net cash flows the carrying cost of the impaired property is compared to the estimated fair value and the difference is recorded as in impairment loss. Management's estimate of fair value takes into account many factors such as the present value discount rate, pricing, and when appropriate possible and probable reserves when justified by economic conditions and actual or planned drilling or other development activities.

Under the successful efforts method of accounting, the depletion rate is the current period production as a percentage of the total proved producing reserves. The depletion rate is applied to the net book value of property costs to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 years.

Income Taxes

Under SFAS No. 109, *"Accounting for Income Taxes,"* deferred income taxes are recognized at each year end for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the reliability of our deferred tax assets. We consider future taxable income in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, it is reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas.

ITEM 3. PROPERTIES

The Company has one primary facility located in The Woodlands, Texas. The Woodlands facility is 6,150 rentable square feet of office space. The Woodlands facility is occupied under a lease that commenced on November 1, 2004 and ends on October 31, 2009. Our rental expense for this facility is $10,763 per month for the first year and increases by $0.75 per square foot per year. The Company is obligated to pay their proportionate share of operating expenses of the property.

Additionally, the Company has acquired the following leases and mineral rights to recover oil and natural gas within the United States:

Belton Field - Muhlenberg County, Kentucky

In April 2004, the Company purchased the mineral rights on approximately 3,008 acres in Muhlenberg County Kentucky, an oil and gas field in the Illinois Basin, in west-central Kentucky. In 2006 and 2007, the Company leased the mineral rights to an additional 6,317 acres and is currently negotiating the lease of the mineral rights on an additional 11,855 acres. Oil was discovered in this basin about 150 years ago. When the Company acquired the rights on the original 3,008 acres, the above-the-ground pumping and storage units had fallen into disrepair and the field was idle. The field was originally discovered in 1939 and developed to produce oil from shallow zones. The first well was completed in the McClosky Limestone (TD 1,541'). Coal was discovered on the property and much of that coal was "mined-out" during strip mining operations. All mining operations ceased decades ago and the mines were reclaimed and are now pastures. Natural gas was discovered in the northwest corner of the field in the 1980s and continued to produce natural gas until recently. There are four known producing horizons on the property. These include (1) a shallow Pennsylvanian oil-bearing zone; (2) the upper-Mississippian oil-bearing Hardinsburg Sandstone; (3) the upper-Mississippian-period's Jackson Sandstone that has significant gas indicated in two wells drilled on the northeast border of the property; and (4) the lower-Mississippian-period's St. Genevieve Limestone (the oil-bearing McClosky zone). The Company's drilling program includes the drilling of a significant number of new wells in this field in 2008.

The Marion Field - Union Parish, Louisiana

In December 2005, the Company leased shallow mineral rights (down to 3,200 feet) on approximately 21,500 acres in Union Parrish, Louisiana, which is a natural gas field currently producing revenues of $1.4 million annually from 476 wells, and with proved developed reserves of 1,788 MMcf. The Marion field is part of the larger Monroe Gas field which was the largest gas field in the United States in the early-to-mid 1900's. It should be noted that in 2005 state records indicated that the Monroe Gas Field produced over 7.0 Tcf. It is located in Northeast Louisiana, in Union Parish which has 8,558 wells. The oil producing Cotton Valley and Smackover formations are also present within the leasehold. In addition, in December 2005, the Company leased deep mineral rights (down to 9,500 feet) on approximately 8,000 acres of the 21,500 acres that will allow the Company to explore this deeper zone. The Company believes that existing oil and gas prices, together with new techniques for stimulating production will make additional drilling and well workover activities in this field commercially viable.

The Delhi Field - Richland Parish, Louisiana

In December 2006, the Company acquired mineral right leases on 1,400 acres in the Delhi Field, in north-east Louisiana. The Company's lease encompasses a portion of approximately 13,636 acres comprising the Delhi Holt Bryant Unit and Mengel Unit. Oil production in this field has traditionally utilized secondary recovery in which water is injected into the reservoir formation to displace residual oil. The water from injection wells physically sweeps the displaced oil to adjacent production wells. Water is produced primarily from the Holt Bryant and injected into the Mengel. The Company believes that improper placement of injection wells has created reservoir channeling and is not sweeping the oil from the majority of the formation. The Company's 2008 drilling program involves converting existing wellbores to water injection wells, repairing shut-in wells, using new technology and replacing inefficient downhole pumps, all of which the Company believes will enhance the efficiency of the waterflood and increase production while allowing a higher percentage of residual oil to be produced.

The Days Creek Field - Miller County, Arkansas

In November 2006, the Company acquired a mineral rights lease on 740 acres in Miller County, Arkansas in the Days Creek Field. The field was originally discovered by American Petro Fina in 1972. According to state records, the cumulative production from this field has been approximately 8.6 million barrels of oil and 6 BCF of natural gas. The primary zone is the Smackover limestone at approximately 8,100 - 8,500 feet. Currently there are four producing oil wells. The Norphlet Sand is present at deeper depths between 8,900 and 11,000 feet. Seismic data in the area indicates the possibility of oil and gas productive potential in this zone.

The Stephens Field at Smackover - Ouachita County, Arkansas

In January 2007, the Company acquired a mineral rights lease on approximately 1,300 acres in Ouachita County, Arkansas with access to the Smackover formation. Smackover production is widespread and prolific in this section of the state. It is nearby at Stephens to the north and at McNeil to the south. Modern gamma ray-neutron/density logs show the presence of oil and gas in many of the 40 to 50 sands in the Travis Peak and Cotton Valley sections from 3,000 to 6,000 feet.

Hospah, Lone Pine & Clovis Field - McKinley County, New Mexico

In 2006 and 2007, the Company acquired mineral rights leases on approximately 2,080 acres in the Hospah Field and Lone Pine Field in McKinley County, New Mexico. The Company is currently negotiating to acquire a 100% working interest and an 80% net revenue interest on an additional 1,280 acres in the Clovis field. The Hospah Field was discovered in 1924 and has produced oil for many years. The Upper Hospah Sandstone of Cretaceous Age produced 5 million barrels by 1974. The Lone Pine Field was found just south of Hospah in 1970 and oil was discovered from the productive Dakota Sandstone at a depth of between 2,500 and 3,800 feet. Most of all the oil development in these fields was done by Tenneco. Oil and gas production from the Hospah Sandstones reservoirs from 1927 to 2005 has yielded nearly 22 million barrels of oil and nearly 53 Mcf of gas.

South Belridge Field, Kern County, California

In 2005, Maxim negotiated a JOA with Orchard Petroleum, Inc. to participate in Orchard’s drilling operations on a prospect of approximately 960-acre in Kern County, California. In early 2007, the Company paid $500,000 for a 50% working interest in 600 acres of section 18 which is adjacent to the original 960 acre prospect. The South Belridge field was discovered in April of 1911 with the completion of Well No. 101 by Belridge Oil Company. In December 1979, Shell Oil Company purchased Belridge Oil Company and the majority of South Belridge production for $3.65 billion. Originally considered to be a minor field in 1995, the South Belridge field reached one billion barrels of cumulative oil production, the sixth field in California to do so and the 15th field in the nation. By supporting Orchard’s drilling operations the Company believes that it could monetize this property to assist in resolving some of the Company’s debt. In April 2008 the Company sold South Belridge in order to reduce indebtedness.

Medicine Lodge Field, Medicine Lodge, Kansas

Maxim acquired a section of property, 640 acres, as partial consideration of a lawsuit settlement in 2005. The Company decided not to develop this field and allowed the leases to expire in late 2007 and early 2008.

Oil and Natural Gas Reserve Estimates

For information relating to: Reserves; Costs Incurred; Drilling Activity; Productive Wells; and Acreage, please refer to ITEM 1. Description of Business, Sections (C) and (D), beginning on page 3.

ITEM 4. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Beneficial ownership is determined in accordance with the rules of the SEC, and generally includes voting power and/or investment power with respect to the securities held. Shares of common stock subject to options currently exercisable or exercisable within 60 days of May 31, 2008 are deemed outstanding and beneficially owned by the person holding such options for purposes of computing the number of shares and percentage beneficially owned by such person, but are not deemed outstanding for purposes of computing the percentage beneficially owned by any other person. Except as indicated in the footnotes to these tables, and subject to applicable community property laws, the persons or entities named have sole voting and investment power with respect to all shares of our common stock shown as beneficially owned by them.

The following table sets forth certain information known to us as of May 31, 2008 with respect to each beneficial owner of more than five percent of the Company's common stock. The percentage ownership is based on 125,474,313 shares of common stock outstanding as of May 31, 2008.

Name and Address of Beneficial Owner	**Common Stock Beneficially Owned**	**Percentage of Class**
Maxim TEP Limited 1 London Wall London EC 2Y 5AB	21,700,000	17.3%
Harvey Pensack *(1)* 7309 Barclay Court University Park, FL 34201	12,352,421	9.6%
Carl Landers *(2)* 141 S. Union Street Madisonville, KY 42431	7,275,000	5.8%
Robert McCann *(3)* 160 Yacht Club Way Hypoluxo, FL 33462	6,618,334	5.3%

(1) Includes (i) 1,216,250 shares issuable pursuant to outstanding warrants, (ii) 450,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008, and (iii) 1,818,182 shares of voting preferred stock. Also includes 3,983,779 shares held by the Harvey Pensack Revocable Living Trust of which Mr. Pensack is a trustee, and 2,228,042 shares held by Joan Pensack, Mr. Pensack's wife.

(2) Includes 600,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(3) Includes 150,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

The following table sets forth beneficial ownership of the Company's common stock as of May 31, 2008 for each of the named executive officers and directors individually and as a group. The table includes any named executive officer or director that served in that capacity for any time during 2007 to May 31, 2008. The percentage ownership is based on 125,474,313 shares of common stock outstanding as of May 31, 2008.

Name and Address of Beneficial Owner	Common Stock Beneficially Owned	Percentage of Class
Harvey Pensack (1) 7309 Barclay Court University Park, FL 34201	12,352,421	9.6%
Carl Landers (2) 141 S. Union Street Madisonville, KY 42431	7,275,000	5.8%
W. Marvin Watson (3) 9400 Grogan's Mill Road, St 205 The Woodlands, TX 77380	5,566,549	4.4%
Dr. John P. Ritota, Jr. (4) 919 Seagate Drive Delray Beach, FL 33483	4,126,667	3.2%
Dan Williams (5) 594 Sawdust Road #382 The Woodlands, TX 77380	3,105,528	2.5%
Eugene Fusz (6) 223 Park Avenue Palm Beach, FL 33401	2,669,232	2.1%
Robert Sepos (7) 87 Robindale Circle The Woodlands, TX 77382	2,835,877	2.2%
John J. Dorgan (8) 555 Byron Street Palo Alto, CA 94301	1,965,675	1.6%
Dominick F. Maggio (9) 2205 Riva Row, Suite 2113 The Woodlands, TX 77380	1,300,339	1.0%
Robert D. Johnson (10) 13606 Bermuda Dunes Court Houston, TX 77069	1,695,768	1.3%
Steve Warner (11)	1,025,000	0.8%

400 N Flagler Drive, #1601 Delray Beach, FL 33401		
Glenn Biggs (12) 1208 South Main Street Boerne, TX 78006	550,397	0.4%
All Directors and officers as a group (12) persons	44,468,453	32.2%

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(1) Includes (i) 1,216,250 shares issuable pursuant to outstanding warrants, (ii) 450,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008, and (iii) 1,818,182 shares of voting preferred stock. Also includes 3,983,779 shares held by the Harvey Pensack Revocable Living Trust of which Mr. Pensack is a trustee, and 2,228,042 shares held by Joan Pensack, Mr. Pensack's wife.

(2) Includes 600,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(3) Includes (i) 2,500 shares issuable upon exercise of warrants, and (ii) 600,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(4) Includes (i) 1,650,000 shares issuable upon exercise of outstanding warrants, and (ii) 600,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(5) Includes 450,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008. Also includes 125,000 shares held by the Matthew Williams Irrevocable Trust of which Mr. Williams is a trustee.

(6) Includes 550,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008. Also includes 2,119,232 shares held by the Eugene Fusz Trust dtd 9/16/05 of which Mr. Fusz is a trustee.

(7) Includes (i) 206,666 shares held by The Sepos Family Limited Partnership of which Mr. Sepos is the general partner, and (ii) 1,000,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(8) Includes (i) 1,375,000 shares issuable pursuant to options exercisable within 60 days of May 31,2008.

(9) Includes (i) 300,339 shares held by AMDG Incorporated, a company controlled by Mr. Maggio, and (ii) 1,000,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(10) Includes 547,456 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(11) Includes 300,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

(12) Includes 300,000 shares issuable pursuant to options exercisable within 60 days of May 31, 2008.

ITEM 5. DIRECTORS AND EXECUTIVE OFFICERS

The following is a list of the directors and executive officers of the Company on May 31, 2008.

Name	**Age**	**Position**	**Year First Elected or Appointed**
W. Marvin Watson	83	Chairman of the Board, CEO	2004
Carl Landers	63	Director	2004
Harvey Pensack	84	Director	2004
John P. Ritota	57	Director	2004
Robert Johnson	61	Director, President	2008

At the beginning of 2007, Mr. Steve Warner and Mr. Eugene Fusz served on the Company's Board of Directors, but at the Company's April 2007 shareholders meeting, they were not re-nominated to the Board of Directors.