MAXIM TEP, INC
Form 10-12G/A
June 11, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549
Amendment No. 2
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**		**Undeveloped Acreage**		**Total Acreage**	
				Gross	**Net**	**Gross**	**Net**	**Gross**	**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

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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 disciplin