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

FORM 10-K

x ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended March 31, 2009

or

¨ TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 000-30234

ENERJEX RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Nevada	**88-0422242**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

27 Corporate Woods, Suite 350 **10975 Grandview Drive** **Overland Park, Kansas**	**66210**
(Address of principal executive offices)	(Zip Code)

7300 W. 110th, 7th Floor **Overland Park, Kansas**	**66210**
(Former Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (913) 754-7754

Securities registered pursuant to Section 12(b) of the Exchange Act:

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Stock, $0.001 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
¨ Yes x No

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

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

Indicate by checkmark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ No x

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $15,197,050

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: 4,443,512 shares of common stock, $0.001 par value, outstanding on July 14, 2009.

DOCUMENTS INCORPORATED BY REFERENCE

List hereunder the following documents if incorporated by reference and the Part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: (1) Any annual report to security holders; (2) Any proxy or information statement; and (3) Any prospectus filed pursuant to Rule 424(b) or (c) under the Securities Act of 1933. The listed documents should be clearly described for identification purposes (e.g., annual report to security holders for fiscal year ended December 24, 1980).

NONE.

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FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, contained in this report, including statements regarding future events, our future financial performance, business strategy and plans and objectives of management for future operations, are forward-looking statements. We have attempted to identify forward-looking statements by terminology including “anticipates,” “believes,” “can,” “continue,” “could,” “estimates,” “expects,” “intends,” “may,” “plans,” “potential,” “predicts” or “should” or the negative of these terms or other comparable terminology. Although we do not make forward-looking statements unless we believe we have a reasonable basis for doing so, we cannot guarantee their accuracy. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, including the risks outlined under “Risk Factors” or elsewhere in this report, which may cause our or our industry’s actual results, levels of activity, performance or achievements to be materially different from any future results, levels of activity, performance or achievements expressed or implied by these forward-looking statements. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time and it is not possible for us to predict all risk factors, nor can we address the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause our actual results to differ materially from those contained in any forward-looking statements. The factors impacting these risks and uncertainties include, but are not limited to:

- inability to attract and obtain additional development capital;
- inability to achieve sufficient future sales levels or other operating results;
- inability to efficiently manage our operations;
- potential default under our secured obligations or material debt agreements;
- estimated quantities and quality of oil and natural gas reserves;
- declining local, national and worldwide economic conditions;
- fluctuations in the price of oil and natural gas;
- the inability of management to effectively implement our strategies and business plans;
- approval of certain parts of our operations by state regulators;
- inability to hire or retain sufficient qualified operating field personnel;
- increases in interest rates or our cost of borrowing;
- deterioration in general or regional (especially Eastern Kansas) economic conditions;
- occurrence of natural disasters, unforeseen weather conditions, or other events or circumstances that could impact our operations or could impact the operations of companies or contractors we depend upon in our operations;
- inability to acquire mineral leases at a favorable economic value that will allow us to expand our development efforts;
- adverse state or federal legislation or regulation that increases the costs of compliance, or adverse findings by a regulator with respect to existing operations; and

- changes in U.S. GAAP or in the legal, regulatory and legislative environments in the markets in which we operate.

You should not place undue reliance on any forward-looking statement, each of which applies only as of the date of this report. Except as required by law, we undertake no obligation to update or revise publicly any of the forward-looking statements after the date of this report to conform our statements to actual results or changed expectations. For a detailed description of these and other factors that could cause actual results to differ materially from those expressed in any forward-looking statement, please see “Risk Factors” in this document under ITEM 1A.

All references in this report to “we,” “us,” “our,” “company” and “EnerJex” refer to EnerJex Resources, Inc. and our wholly-owned operating subsidiaries, EnerJex Kansas, Inc. and DD Energy, Inc., unless the context requires otherwise. We report our financial information on the basis of a March 31 fiscal year end. We have provided definitions for the oil and natural gas industry terms used in this report in the “Glossary” beginning on page 23 of this report.

AVAILABLE INFORMATION

We file annual, quarterly and other reports and other information with the SEC. You can read these SEC filings and reports over the Internet at the SEC’s website at www.sec.gov or on our website at www.enerjexresources.com. You can also obtain copies of the documents at prescribed rates by writing to the Public Reference Section of the SEC at 100 F Street, NE, Washington, DC 20549 on official business days between the hours of 10:00 am and 3:00 pm. Please call the SEC at (800) SEC-0330 for further information on the operations of the public reference facilities. We will provide a copy of our annual report to security holders, including audited financial statements, at no charge upon receipt to of a written request to us at EnerJex Resources, Inc., 27 Corporate Woods, Suite 350, 10975 Grandview Drive, Overland Park, Kansas 66210.

INDUSTRY AND MARKET DATA

The market data and certain other statistical information used throughout this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources. In addition, some data are based on our good faith estimates.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES.

Our Business

EnerJex, formerly known as Millennium Plastics Corporation, is an oil and natural gas acquisition, exploration and development company. Midwest Energy, Inc. was incorporated in the State of Nevada on December 30, 2005. In August of 2006, Millennium Plastics Corporation, following a reverse merger by and among us, Millennium Acquisition Sub (our wholly-owned subsidiary) and Midwest Energy, changed the focus of its business plan from the development of biodegradable plastic materials and entered into the oil and natural gas industry. In conjunction with the change, the company was renamed EnerJex Resources, Inc.

Our principal strategy is to focus on the acquisition of oil and natural gas mineral leases that have existing production and cash flow. Once acquired, subject to availability of capital, we strive to implement an accelerated development program utilizing capital resources, a regional operating focus, an experienced management and technical team, and enhanced recovery technologies to attempt to increase production and increase returns for our stockholders. Our oil and natural gas acquisition and development activities are currently focused in Eastern Kansas.

From the beginning of fiscal 2008 through the end of fiscal 2009, we deployed approximately $12 million in capital resources to acquire and develop five operating projects and drill 179 new wells (111 producing wells and 65 water injection wells and 3 dry holes). As a result, our estimated total net proved oil reserves increased from zero at March 31, 2007 to 1.3 million barrels of oil equivalent, or BOE, as of March 31, 2009. Of the 1.3 million BOE of total proved reserves, approximately 39% are proved developed and approximately 61% are proved undeveloped. The proved developed reserves consist of 82% proved developed producing reserves and 18% proved developed non-producing reserves.

The total proved PV10 (present value) of our reserves ("PV10") as of March 31, 2009 was $10.63 million. PV10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 57, for a reconciliation to the comparable GAAP financial measure.

In response to economic conditions and capital market constraints, we have recently begun to explore and evaluate various strategic initiatives that would allow us to continue our plans to grow production and reserves in the mid-continent region of the United States. Initiatives include creating joint ventures to further develop current leases, restructuring current debt, as well as evaluating other options ranging from capital formation to some type of business combination. Though there can be no assurance that any particular outcome will result from this process, we believe there are significant opportunities to increase our growth rates given current market conditions. We believe this process may create options that will allow us to better position EnerJex to take advantage of these opportunities.

The Opportunity in Kansas

According to the Kansas Geological Survey, the State of Kansas has historically been one of the top 10 domestic oil producing regions in the United States. For the years ended December 31, 2008 and 2007, 39.6 million barrels and 36.6 million barrels of oil were produced in Kansas. Of the total barrels produced in Kansas in the calendar year ended December 2007, 15 companies accounted for approximately 29% of the total production, with the remaining 71% produced by over 1,750 active producers.

In addition to significant historical oil and natural gas production levels in the region, we believe that a confluence of the following factors in Eastern Kansas and the surrounding region make it an attractive area for oil and natural gas development activities:

- *Traditional Roll-Up Strategy.* We are seeking to employ a traditional roll-up strategy utilizing a combination of capital resources, operational and management expertise, technology, and our strategic partnership with Haas Petroleum, which has experience operating in the region for nearly 70 years.

- *Numerous Acquisition Opportunities.* There are many small producers and owners of mineral rights in the region, which afford us numerous opportunities to pursue negotiated lease transactions instead of having to competitively bid on fundamentally sound assets.

- *Fragmented Ownership Structure.* There are numerous opportunities to acquire producing properties at attractive prices, because of the currently inefficient and fragmented ownership structure.

Our Properties

The table below summarizes our acreage by project name as of March 31, 2009.

Project Name	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	**Net[(1)]**	**Gross**	**Net[(1)]**	**Gross**	**Net[(1)]**
Black Oaks Project	550	522	1,850	1,758	2,400	2,280
Thoren Project	135	135	591	591	726	726
DD Energy Project	400	400	1,370	1,370	1,770	1,770
Tri-County Project	610	606	652	651	1,262	1,257
Gas City Project	600	600	4,713	4,713	5,313	5,313
Total	**2,295**	**2,263**	**9,176**	**9,083**	**11,471**	**11,346**

(1) Net acreage is based on our net working interest as of March 31, 2009.

Black Oaks Project

On April 9, 2007, we entered into a “Joint Exploration Agreement” with a shareholder, MorMeg, LLC, (MorMeg) whereby we agreed to advance $4.0 million to a joint operating account for further development of MorMeg’s Black Oaks leaseholds in exchange for a 95% working interest in the Black Oaks Project. The Black Oaks Project encompasses approximately 2,400 gross acres in Woodson and Greenwood Counties, Kansas, which at the time of acquisition had approximately 35 oil wells producing an average of approximately 32 barrels of oil per day, or BOPD.

The Black Oaks Project is a primary and enhanced secondary recovery project between us and MorMeg. Phase I of the Black Oaks Project development plan commenced shortly after closing with the drilling of 44 in-fill wells. During fiscal 2008, we began injecting water into the first five water injection wells at an average rate of approximately 50 barrels of water per day per well. This pilot program was expanded so that by June 2008, we were injecting approximately 200 barrels of water per day (bbls water/day) per well in the initial 5 injection wells. Adjacent oil wells showed increased production from an average of approximately 5 BOPD to 25 BOPD. As of March 31, 2009, we are maintaining the 200 bbls water/day average on the injection wells in the pilot program area. We have seen no additional response on this area as of yet. We are also injecting an average of 100 bbls water/day per well in 4 injection wells adjacent to the pilot program area and are closely monitoring data and activities for any resulting increase in production. Based upon the results of our testing, we expect to continue the development plan, subject to availability of capital. Phase II of the plan contemplates drilling over 25 additional water injection wells and drilling over 20 additional producer wells. Project-wide production was an average of approximately 96 BOPD as of March 31, 2009.

We will maintain our 95% working interest until "payout", at which time the MorMeg 5% carried working interest will be converted to a 30% working interest and our working interest becomes 70%. Payout is generally the point in time when the total cumulative revenue from the project equals all of the project's development expenditures and costs associated with funding. Through an additional extension, we have until December 31, 2009 to contribute additional capital toward the Black Oaks Project development. If we elect not to contribute further capital to the Black Oaks Project prior to the project's full development while it is economically viable to do so, or if there is more than a thirty day delay in project activities due to lack of capital, MorMeg has the option to cease further joint development and we will receive an undivided interest in the Black Oaks Project. The extension will have no force and effect, however, upon a material default by EnerJex under the Credit Facility. The undivided interest will be the proportionate amount equal to the amount that our investment bears to our investment plus $2.0 million, with MorMeg receiving an undivided interest in what remains.

As of March 31, 2009, we had proved oil reserves on Phase I of this project of:

	Gross STB(1)	Net STB(2)	PV10(3) (before tax)
Proved, Developed Producing	420,080	197,640	$ 3,781,690
Proved, Developed Non-Producing	50,440	30,450	$ 650,430
Proved, Undeveloped	875,300	352,370	$ 944,100
Total Proved	1,345,820	580,460	$ 5,376,220

(1) STB = one stock-tank barrel.

(2) Net STB is based upon our net revenue interest, including any applicable reversionary interest.

(3) See "Glossary" on page 23 for our definition of PV10 and "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 57, for a reconciliation to the comparable GAAP financial measure.

Thoren Project

On April 27, 2007, we acquired a 100% working interest in the Thoren Project for $400,000 from MorMeg. This project, at the time of acquisition, contained 240 acres in Douglas County, Kansas, with 12 oil wells producing an average of approximately 10 BOPD, 4 water injection wells, and one water supply well. We have leased an additional 486 acres increasing the total acreage of this project to 726 acres.

Through March 31, 2009, we have invested approximately $800,000 for the development of this project and as of March 31, 2009, we had 32 oil wells producing an average of approximately 38 BOPD; along with 16 water injection wells and one water supply well.

As of March 31, 2009, we had proved oil reserves on this project of:

	Gross STB[(1)]	Net STB[(2)]	PV10[(3)] (before tax)
Proved, Developed Producing	48,030	24,600	$ 539,510
Proved, Developed Non-Producing	24,920	7,690	$ 146,490
Proved, Undeveloped	43,020	37,640	$ 85,970
Total Proved	115,970	69,930	$ 771,970

(1) STB = one stock-tank barrel.
(2) Net STB is based upon our net revenue interest, including any applicable reversionary interest.
(3) See "Glossary" on page 23 for our definition of PV10 and "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 57, for a reconciliation to the comparable GAAP financial measure.

We will maintain our 100% working interest until "payout" and our working interest will become 75%, at which time the MorMeg working interest will be converted to a 25% working interest. Payout for this project occurs at that point in time when the total cumulative revenue from production equals the total amount of the purchase price, all costs and expenses incurred by us in the development and operation, and loan and interest costs incurred in the finance and funding of the purchase.

We have identified an additional 7 drillable producer locations and 8 drillable injector locations on this project.

DD Energy Project

Effective September 1, 2007, we acquired a 100% working interest in the DD Energy Project for $2.7 million, which consisted of approximately 1,500 acres in Johnson, Anderson and Linn Counties, Kansas. At the time of acquisition, this project was producing an average of approximately 45 BOPD.

In addition, we have acquired additional leases bringing the total acreage for this project to approximately 1,700 acres. As of March 31, 2009, we had 110 oil wells, 41 water injection wells and 2 water supply wells on this project with production averaging approximately 61 BOPD. Through March 31, 2009, we have invested an additional $2.4 million in this project and have drilled 41 water injection wells and 34 producing wells. We have seen some indication of an initial response from 5 of the injectors and are closely monitoring data and activities for any resulting increase in production.

As of March 31, 2009, we had proved oil reserves on this project of:

	Gross STB[(1)]	Net STB[(2)]	PV10[(3)] (before tax)
Proved, Developed Producing	75,510	64,700	$ 972,220
Proved, Developed Non-Producing	23,070	19,470	$ 183,090
Proved, Undeveloped	39,390	31,840	$ 85,030
Total Proved	137,970	116,010	$ 1,240,340

(1) STB = one stock-tank barrel.
(2) Net STB is based upon our net revenue interest, including any applicable reversionary interest.
(3) See “Glossary” on page 23 for our definition of PV10 and “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Reserves” page 57, for a reconciliation to the comparable GAAP financial measure.

We have identified an additional 88 drillable producer locations and 86 drillable injector locations on this project.

Tri-County Project

On September 14, 2007, we acquired nearly a 100% working interest in the Tri-County Project for $800,000, which consisted of approximately 1,100 acres in Miami, Johnson and Franklin Counties, Kansas. At the time of acquisition, this project was producing an average of approximately 25 BOPD.

Through March 31, 2009, we have invested approximately $700,000 towards the development of this project. Funds have been used to drill four producer wells, make infrastructure upgrades, and perform work-overs on approximately 20 wells in this project. We have also acquired additional leases, bringing the total project to approximately 1,300 acres.

As of March 31, 2009, the Tri-County Project consisted of 166 producing wells and 59 water injection wells with production averaging approximately 49 BOPD.

As of March 31, 2009, we had proved oil reserves on this project of:

	Gross STB[(1)]	Net STB[(2)]	PV10[(3)] (before tax)
Proved, Developed Producing	177,560	141,330	$ 1,369,700
Proved, Developed Non-Producing	48,190	37,940	$ 479,270
Proved, Undeveloped	474,210	380,030	$ 1,361,430
Total Proved	699,960	559,300	$ 3,210,400

(1) STB = one stock-tank barrel.
(2) Net STB is based upon our net revenue interest, including any applicable reversionary interest.
(3) See “Glossary” on page 23 for our definition of PV10 and “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Reserves” page 57, for a reconciliation to the comparable GAAP financial measure.

We have identified an additional 83 drillable producer locations and 90 drillable injector locations on this project.

Gas City Project

In August of 2007, we entered into a development agreement with Euramerica Energy, Inc., or Euramerica, to further the development and expansion of the Gas City Project, which included 6,600 acres, whereby Euramerica contributed $524,000 in capital toward the project. Euramerica was granted an option to purchase this project for $1.2 million with a requirement to invest an additional $2.0 million for project development by August 31, 2008. We were the operator of the project at a cost plus 17.5% basis. We received $600,000 of the $1.2 million purchase price and $500,000 of the $2.0 million development funds.

On September 15, 2008, we amended the well development agreement to extend the date on which Euramerica was required to make its third and fourth quarterly installment payments of the purchase price to October 15, 2008. The amendment also extended until November 15, 2008 the requirement to fund the remaining $1.5 million in development capital.

On October 15, 2008, we again amended the agreement with Euramerica for the purchase of the Gas City Project to include the following material changes to the Euramerica agreement, as amended, extended and supplemented:

- Euramerica was granted an extension until January 15, 2009 (with no further grace periods) to pay the remaining $600,000 of the purchase price for its option to purchase an approximately 6,600 acre portion of the Gas City Project and $1.5 million in previously due development funds for the Gas City Project;
- If Euramerica fails to fully fund both the purchase price and these development funds by January 15, 2009, Euramerica will lose all rights to the Gas City Project and assets and there will be no payout from the revenue of the wells on this project;
- The oil zones and production from such oil zones in two oil wells then became 100% owned by EnerJex;
- We may deduct from the development funds all amounts owed to us prior to applying the funds to any actual development;
- Euramerica specifically recognized that we can shut in or stop the development of the project if the project is not producing in paying quantities or if the project is operating at a loss. The decision to shut in the project and cease all operations was made on October 15, 2008; and
- If Euramerica funds the remaining portion of the purchase price for its option and the development funds in the Gas City Project on or before January 15, 2009, “Payout” as used in the Assignment and other documents is now based on “drilling and completion costs on a well-by-well basis.”

Subsequently, Euramerica failed to fully fund by January 15, 2009 both the balance of the purchase price and the remaining development capital owed under the Amended and Restated Well Development Agreement and Option for “Gas City Property” between us and Euramerica. Therefore, Euramerica has forfeited all of its interest in the property, including all interests in any wells, improvements or assets, and all of Euramerica's interest in the property reverts back to us. In addition, all operating agreements between us and Euramerica relating to the Gas City Project are null and void.

We drilled 22 wells on behalf of Euramerica under the development agreement. We are currently exploring options to sell or further develop the Gas City Project through joint venture partnerships or other opportunities. The gas project remains shut in and certain leases approximating 1,300 acres were not renewed upon expiration. As of March 31, 2009 we were producing an average of approximately 10 BOPD from the two oil wells now 100% owned by us.

As of March 31, 2009, we had proved oil and natural gas reserves on this project of:

	Gross STB[1]	Net STB[2]	Gross MCF[3]	Net MCF[4]	PV10[5] (before tax)
Proved, Developed Producing	1,400	1,150	-	-	$ 28,430
Proved, Developed Non-Producing	-	-	-	-	$ -
Proved, Undeveloped	11,850	9,780	-	-	$ 1,970
Total Proved	13,250	10,930	-	-	$ 30,400

(1) STB = one stock-tank barrel.
(2) Net STB is based upon our net revenue interest, including any applicable reversionary interest.
(3) MCF = thousand cubic feet of natural gas. There were no natural gas reserves at March 31, 2009.
(4) Net MCF is based upon our net revenue interest. There were no natural gas reserves at March 31, 2009.
(5) See “Glossary” on page 23 for our definition of PV10 and “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Reserves” page 57, for reconciliation to the comparable GAAP financial measure.

Brownrigg Project

We entered into an agreement with Pharyn Resources (Pharyn) on June 1, 2009 to begin a 20 well development program on EnerJex’s Brownrigg lease in Linn County, Kansas. We contributed the 320 acre property in exchange for a 10% carried working interest and a cost-plus management fee. Pharyn will contribute up to $700,000 in initial development capital. We intend to develop the project and remain the operator of the property. We will be working with Pharyn in this, our first joint venture project and feel we have an agreement that pairs our drilling and operating background with Pharyn’s investment objectives, which is intended to build long-term sustainable earnings growth for both companies. As of the date of this report, we have drilled 5 wells and are in various stages of completion.

Our Business Strategy

Our principal strategy has been to focus on the acquisition of oil and natural gas mineral leases that have existing production and cash flow. Once acquired, subject to availability of capital, we strive to implement an accelerated development program utilizing capital resources, a regional operating focus, an experienced management and technical team, and enhanced recovery technologies to attempt to increase production and increase returns for our stockholders. Our oil and natural gas acquisition and development activities are currently focused in Eastern Kansas. Depending on availability of capital, and other restraints, our goal is to increase stockholder value by finding and developing oil and natural gas reserves at costs that provide an attractive rate of return on our investments. The principal elements of our business strategy are:

- *Develop Our Existing Properties.* We intend to create reserve and production growth from over 400 additional drilling locations we have identified on our properties. We have identified an additional 193 drillable producer locations and 213 drillable injector locations. The structure and the continuous oil accumulation in Eastern Kansas, and the expected long-life production and reserves of our properties, are anticipated to enhance our opportunities for long-term profitability.

- *Maximize Operational Control.* We seek to operate our properties and maintain a substantial working interest. We believe the ability to control our drilling inventory will provide us with the opportunity to more efficiently allocate capital, manage resources, control operating and development costs, and utilize our experience and knowledge of oilfield technologies.

- *Pursue Selective Acquisitions and Joint Ventures.* Due to our local presence in Eastern Kansas and strategic partnership with Haas Petroleum, we believe we are well-positioned to pursue selected acquisitions, subject to availability of capital, from the fragmented and capital-constrained owners of mineral rights throughout Eastern Kansas.

- *Reduce Unit Costs Through Economies of Scale and Efficient Operations.* As we increase our oil production and develop our existing properties, we expect that our unit cost structure will benefit from economies of scale. In particular, we anticipate reducing unit costs by greater utilization of our existing infrastructure over a larger number of wells.

We are continually evaluating oil and natural gas opportunities in Eastern Kansas and are also in various stages of discussions with potential joint venture ("JV") partners who would contribute capital to develop leases we currently own or would acquire for the JV. Subsequent to year-end (in June 2009), we entered into one such opportunity on the Brownrigg lease in Linn County, Kansas, as discussed above. This economic strategy is anticipated to allow us to utilize our own financial assets toward the growth of our leased acreage holdings, pursue the acquisition of strategic oil and natural gas producing properties or companies and generally expand our existing operations while further diversifying risk. Subject to availability of capital, we plan to continue to bring potential acquisition and JV opportunities to various financial partners for evaluation and funding options. It is our vision to grow the business in a disciplined and well-planned manner.

We began generating revenues from the sale of oil during the fiscal year ended March 31, 2008. Subject to availability of capital, we expect our production to continue to increase, both through development of wells, through our acquisition strategy, and other strategic initiatives. Our future financial results will continue to depend on: (i) our ability to source and screen potential projects; (ii) our ability to discover commercial quantities of natural gas and oil; (iii) the market price for oil and natural gas; and (iv) our ability to fully implement our exploration, work-over and development program, which is in part dependent on the availability of capital resources. There can be no assurance that we will be successful in any of these respects, that the prices of oil and natural gas prevailing at the time of production will be at a level allowing for profitable production, or that we will be able to obtain additional funding at terms favorable to us to increase our currently limited capital resources. For a detailed description of these and other factors that could materially impact actual results, please see "Risk Factors" in this document under ITEM 1A.

The board of directors has implemented a crude oil and natural gas hedging strategy that will allow management to hedge up to 80% of our net production to mitigate a majority of our exposure to changing oil prices in the intermediate term.

Our Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our strategy:

- *Acquisition and Development Strategy.* We have what we believe to be a relatively low-risk acquisition and development strategy compared to some of our competitors. We generally buy properties that have proven current production, with a projected pay-back within a relatively short period of time, and with potential growth and upside in terms of development, enhancement and efficiency. We also plan to minimize the risk of natural gas and oil price volatility by developing a sales portfolio of pricing for our production as it expands and as market conditions permit.

- *Significant Production Growth Opportunities.* We have acquired an attractive acreage position with favorable lease terms in a region with historical hydrocarbon production. Based on drilling success we have had within our acreage position and subject to availability of capital, we expect to increase our reserves, production and cash flow.

- *Experienced Management Team and Strategic Partner with Strong Technical Capability.* Our CEO has over 20 years of experience in the energy industry, primarily related to gas/electric utilities, but including experience related to energy trading and production, and members of our board of directors have considerable industry experience and technical expertise in engineering, horizontal drilling, geoscience and field operations. In addition, our strategic partner, Haas Petroleum, has over 70 years of experience in Eastern Kansas, including completion and secondary recovery techniques and technologies. Our board of directors and Mark Haas of Haas Petroleum work closely with management during the initial phases of any major project to ensure its feasibility and to consider the appropriate recovery techniques to be utilized.

- *Incentivized Management Ownership.* The equity ownership of our directors and executive officers is strongly aligned with that of our stockholders. As of July 14, 2009, our directors and executive officers owned approximately 9.1% of our outstanding common stock, with options that upon exercise would increase their ownership of our outstanding common stock to 15.6%.

Company History

Midwest Energy, Inc. was incorporated in the State of Nevada on December 30, 2005. Prior to the reverse merger with Midwest Energy in August of 2006, we operated under the name Millennium Plastics Corporation and focused on the development of biodegradable plastic materials. This business plan was ultimately abandoned following its unsuccessful implementation. Following the merger, we assumed the business plan of Midwest Energy and entered into the oil and natural gas industry. Concurrent with the effectiveness of the merger, we changed our name to "EnerJex Resources, Inc." The result of the merger was that the former stockholders of Midwest Energy controlled approximately 98% of our outstanding shares of common stock. In addition, Midwest Energy was deemed to be the acquiring company for financial reporting purposes and the merger was accounted for as a reverse merger. In November 2007 Midwest Energy changed its name to EnerJex Kansas. All of our current operations are conducted through EnerJex Kansas and DD Energy, our wholly-owned subsidiaries.

Significant Developments in Fiscal 2009

The following is a brief description of our most significant corporate developments that occurred in fiscal 2009:

- On March 6, 2008 we entered into an agreement with Shell Trading (US) Company, or Shell, whereby we agreed to an 18-month fixed-price swap with Shell for 130 BOPD at a fixed price per barrel of $96.90, before transportation costs from April 1, 2008 through September 30, 2009. This represented approximately 60% of our total oil production on a net revenue basis at that time and locked in approximately $6.8 million in gross revenue before transportation costs over the 18 month period. In addition, we agreed to sell all of our remaining oil production at current spot market pricing beginning April 1, 2008 through September 30, 2009 to Shell. For the fiscal year ended March 31, 2009, the positive impact on our net revenue from the fixed-price swap was approximately $506,000.

- On July 3, 2008, EnerJex, EnerJex Kansas, and DD Energy entered into a three-year $50 million Senior Secured Credit Facility (the "Credit Facility") with Texas Capital Bank, N.A. Borrowings under the Credit Facility will be subject to a borrowing base limitation based on our current proved oil and gas reserves and will be subject to semi-annual redeterminations and other interim adjustments. The initial borrowing base was set at $10.75 million and was reduced to $7.428 million following the liquidation of the BP hedging instrument in November 2008. The borrowing base was reviewed by Texas Capital Bank in February 2009 and it was determined that it shall be reduced by $200,000 per month beginning April 2009 with the expectation that this monthly reduction would continue through December 2009. We had borrowings $7.328 million outstanding at March 31, 2009. Subsequent to year-end, we have made an additional $200,000 of payments to reduce the borrowing base. The Credit Facility is secured by a lien on substantially all assets of the Company and its subsidiaries. The Credit Facility has a term of three years, and matures on July 3, 2011. The Credit Facility also provides for the issuance of letters-of-credit up to a $750,000 sub-limit under the borrowing base and up to an additional $2.25 million limit not subject to the borrowing base to support our hedging program.

- On July 7, 2008, we amended the $2.7 million of aggregate principal amount of our 10% debentures that remain outstanding to, among other things, permit the indebtedness under our Credit Facility, subordinate the security interests of the debentures to the Credit Facility, provide for the redemption of the remaining debentures with the net proceeds from any next debt or equity offering, eliminate the covenant to maintain certain production thresholds and waive all known defaults. Subsequent to year-end, we again amended the debentures to extend the maturity date to September 30, 2010, to allow us to pay interest in either cash or payment-in-kind interest (an increase in the amount of principal due) or payment of interest through the issuance of shares of common stock, and add a provision for the conversion of the debentures into shares of our common stock. Through May 31, 2010 the conversion price per share equals $3.00. From June 1, 2010 through the Maturity Date, assuming the debenture has not been redeemed, the conversion price per share equals that price which shall be computed as 100.0% of the arithmetic average of the Weighted Average Price of the Common Stock on each of the thirty (30) consecutive Trading Days immediately preceding the Conversion Date, and considering adjustments, if any, as specified in the amendment.

- As of July 3, 2008, we entered into an ISDA master agreement and a costless collar with BP Corporation North America Inc., or BP, for 130 barrels of oil per day with a price floor of $132.50 per barrel and a price ceiling of $155.70 per barrel for NYMEX West Texas Intermediate for the period of October 1, 2009 until March 31, 2011. We liquidated this costless collar in November 2008 and received proceeds of approximately $3.9 million from BP. We reduced the debt outstanding under our Credit Facility by approximately $3.3 million and used the remainder for general operating purposes.

- On August 1, 2008, we executed three-year employment agreements with C. Stephen Cochennet, our chief executive officer, and Dierdre P. Jones, our chief financial officer. Mr. Cochennet and Ms. Jones have agreed to amend their employment agreements to reflect options rescinded in November 2008.

- Euramerica failed to fully fund by January 15, 2009 both the balance of the purchase price and the remaining development capital owed under the Amended and Restated Well Development Agreement and Option for “Gas City Property” between us and Euramerica. Therefore, Euramerica has forfeited all of its interest in the property, including all interests in any wells, improvements or assets, and all of Euramerica's interest in the property reverts back to us. In addition, all operating agreements between us and Euramerica relating to the Gas City Project are null and void.

- In February 2009, we entered into a fixed price swap transaction under the terms of the BP ISDA for a total of 120,000 gross barrels at a price of $57.30 per barrel before transportation costs for the period beginning October 1, 2009 and ending on December 31, 2013.

- We recorded a non-cash impairment of $4,777,723 to the carrying value of our proved oil and gas properties during the fiscal year ended March 31, 2009. The impairment is primarily attributable to lower prices for both oil and natural gas. The charge results from the application of the "ceiling test" under the full cost method of accounting at December 31, 2008. Under full cost accounting requirements, the carrying value may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. A ceiling test charge occurs when the carrying value of the oil and gas properties exceeds the full cost ceiling.

- We accrued but did not pay interest due at March 31, 2009 to our subordinated debenture holders on the $2.7 million outstanding as of that date. Subsequent to year-end, we agreed to pay the accrued interest on a payment-in-kind basis.

Relationship with Haas Petroleum

In April of 2007, we entered into a consulting agreement with Mark Haas, President of Haas Petroleum and managing member of MorMeg. This agreement provides that Mr. Haas will consult with us at an executive level regarding field development, acquisition evaluation, identification of additional acquisition opportunities and overall business strategy. Haas Petroleum has been in the oil exploration and production business for over 70 years and Mark Haas has been in the business for over 30 years.

We believe that this relationship provides us with a competitive advantage when evaluating and sourcing acquisition opportunities. As a long-term producer and oil field service provider, Haas Petroleum has existing relationships with numerous oil and natural gas producers in Eastern Kansas and is generally aware of existing opportunities to enhance many of these properties through the deployment of capital, and application of enhanced drilling and production technologies. We believe that we will be able to leverage the experience and relationships of Mr. Haas to compliment our business strategy. To date, Mr. Haas has helped us identify and evaluate all of our property acquisitions, and has been instrumental in the creation and implementation of our development plans of these properties.

One of our fundamental goals with respect to the consulting arrangement is to align the interests of Mr. Haas with those of ours as much as possible. As a result, the consulting agreement provides that we will pay him five thousand dollars per month. In addition, we have granted Mr. Haas options to purchase 60,000 shares of our common stock at an exercise price of $6.25 per share, expiring on May 3, 2011. Finally, we have utilized our common stock, in part, for the purchase of assets owned by MorMeg, which we believe will further align our business interests with those of Mr. Haas.

Drilling Activity

The following table sets forth the results of our drilling activities during the 2007, 2008 and 2009 fiscal years.

Drilling Activity

	Gross Wells			Net Wells[1]		
Fiscal Year	Total	Producing	Dry	Total	Producing	Dry
2007 Exploratory	-0-	-0-	-0-	-0-	-0-	-0-
2008 Exploratory	10	10	-0-	10	10	-0-
2009 Exploratory[2]	12	12	-0-	12	12	-0-
2007 Development	-0-	-0-	-0-	-0-	-0-	-0-
2008 Development	59	57	2	58	56	2
2009 Development	96	95	1	96	95	1

(1) Net wells are based on our net working interest as of March 31, 2009.

(2) We incurred some exploration costs related to exploratory wells drilled on behalf of Euramerica.

Net Production, Average Sales Price and Average Production and Lifting Costs

The table below sets forth our net oil and natural gas production (net of all royalties, overriding royalties and production due to others) for the fiscal years ended March 31, 2009 and 2008 and 2007, the average sales prices, average production costs and direct lifting costs per unit of production.

	Fiscal Year Ended March 31, 2009	Fiscal Year Ended March 31, 2008	Fiscal Year Ended March 31,2007
Net Production			
Oil (Bbl)	74,289	43,697	-0-
Natural gas (Mcf)	12,275	17,762	19,254
Average Sales Prices			
Oil (per Bbl)	$ 85.67	$ 79.71	$ -0-
Natural gas (per Mcf)	$ 5.57	$ 6.20	$ 4.72
Average Production Cost [1]			
Per Bbl of oil	$ 45.01	$ 56.65	$ -0-
Per Mcf of natural gas	$ 15.11	$ 13.12	$ 9.55
Average Lifting Costs [2]			
Per Bbl of oil	$ 33.01	$ 37.08	$ -0-
Per Mcf of natural gas	$ 15.11	$ 9.86	$ 8.95

(1) Production costs include all operating expenses, depreciation, depletion and amortization, lease operating expenses and all associated taxes. Impairment of oil and natural gas properties is not included in production costs.

(2) Direct lifting costs do not include impairment expense or depreciation, depletion and amortization.

Results of Oil and Natural Gas Producing Activities

The following table shows the results of operations from our oil and natural gas producing activities from fiscal years ended March 31, 2007 through March 31, 2009. Results of operations from these activities have been determined using historical revenues, production costs, depreciation, depletion and amortization of the capitalized costs subject to amortization. General and administrative expenses and interest expense have been excluded from this determination.

	For the Fiscal Year Ended March 31, 2009	For the Fiscal Year Ended March 31, 2008	For the Fiscal Year Ended March 31, 2007
Production revenues	$ 6,436,805	$ 3,602,798	$ 90,800
Production costs	(2,637,333)	(1,795,188)	(172,417)
Depreciation, depletion and amortization	(872,230)	(913,224)	(11,477)
Results of operations for producing activities	$ 2,972,242	$ 894,386	$ (93,094)

Producing Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of March 31, 2009.

	Producing			
Project	**Gross Oil**	**Net Oil(1)**	**Gross Natural Gas**	**Net Natural Gas(1)**
Black Oaks Project	62	59	-0-	-0-
Thoren Project	33	33	-0-	-0-
DD Energy Project	114	114	-0-	-0-
Tri-County Project	170	170	-0-	-0-
Gas City Project	-0-	-0-	22	22
Total	**379**	**376**	**22**	**22**

(1) Net wells are based on our net working interest as of March 31, 2009.

Reserves

Our estimated total proved PV10 (present value) before tax of reserves as of March 31, 2009 was $10.63 million, versus $39.6 million as of March 31, 2008. Though total proved reserves were comparable at March 31, 2009 and 2008; 1.3 million and 1.4 million barrels of oil equivalent (BOE), respectively, the PV10 declined dramatically due to the estimated average price of oil at March 31, 2009 of $42.65 versus $94.53 at March 31, 2008. Of the 1.3 million BOE at March 31, 2009 approximately 39% are proved developed and approximately 61% are proved undeveloped. The proved developed reserves consist of proved developed producing (82%) and proved developed non-producing (18%). See "Glossary" on page 23 for our definition of PV10.

Based on an estimated oil price of $42.65 as of March 31, 2009, and applying an annual discount rate of 10% of the future net cash flow, the estimated PV10 of the 1.3 million BOE, before tax, is calculated as set forth in the following table:

Summary of Oil and Natural Gas Reserves
as of March 31, 2009

Proved Reserves Category	Gross STB[1]	Net STB[2]	Gross MCF[3]	Net MCF[4]	PV10[5] (before tax)
Proved, Developed Producing	722,590	429,420	-	-	$ 6,691,550
Proved, Developed Non-Producing	146,620	95,560	-	-	1,459,280
Proved, Undeveloped	1,440,760	811,650	-	-	2,478,510
Total Proved	**2,309,970**	**1,336,630**	**-**	**-**	**$ 10,629,340**

(1) STB = one stock-tank barrel.
(2) Net STB is based upon our net revenue interest, including any applicable reversionary interest.
(3) MCF = thousand cubic feet of natural gas. There we no natural gas reserves at March 31, 2009.
(4) Net MCF is based upon our net revenue interest. There we no natural gas reserves at March 31, 2009.
(5) See "Glossary" on page 23 for our definition of PV10 and "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 57, for a reconciliation to the comparable GAAP financial measure.

Oil and Natural Gas Reserves Reported to Other Agencies

We did not file any estimates of total proved net oil or natural gas reserves with, or include such information in reports to, any federal authority or agency, other than the SEC, during the fiscal year ended March 31, 2009.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements and liens for current taxes and other burdens, including mineral encumbrances and restrictions. Further, our debt is secured by first and second liens substantially on all of our assets. These burdens have not materially interfered with the use of our properties in the operation of our business to date, though there can be no assurance that such burdens will not materially impact our operations in the future.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the natural gas and oil industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel or have title reviewed by professional landmen only when we acquire producing properties or before we begin drilling operations. However, any acquisition of producing properties without obtaining title opinions are subject to a greater risk of title defects.

Sale of Natural Gas and Oil

We do not intend to refine our natural gas or oil production. We expect to sell all or most of our production to a small number of purchasers in a manner consistent with industry practices at prevailing rates by means of long-term and short-term sales contracts, some of which may have fixed price components. We have a long-term purchase contract with Shell to sell all of our current oil production beginning April 1, 2008 through September of 2009. We also have an ISDA master agreement and a fixed price swap with BP beginning October 1, 2009 through December 31, 2013. Under current conditions, we should be able to find other purchasers, if needed. All of our produced oil is held in tank batteries and then each respective purchaser transports the oil by truck to the refinery. In addition, our board of directors has implemented a crude oil and natural gas hedging strategy that will allow management to hedge up to 80% of our net production in an effort to mitigate a majority of our exposure to changing oil prices in the intermediate term.

Secondary Recovery and Other Production Enhancement Strategies

When an oil field is first produced, the oil typically is recovered as a result of natural pressure within the producing formation, often assisted by pumps of various types. The only natural force present to move the crude oil to the wellbore is the pressure differential between the higher pressure in the formation and the lower pressure in the wellbore. At the same time, there are many factors that act to impede the flow of crude oil, depending on the nature of the formation and fluid properties, such as pressure, permeability, viscosity and water saturation. This stage of production is referred to as "primary production," which in Eastern Kansas normally only recovers up to 15% of the crude oil originally in place in a producing formation.

Many, but not all, oil fields are amenable to assistance from a waterflood, a form of "secondary recovery," which is used to maintain or increase reservoir pressure and to help sweep oil to the wellbore. In a waterflood, certain wells are used to inject water into the reservoir while other wells are used to recover the oil in place. We utilize waterflooding as a secondary recovery technique for the majority of our oil field projects.

As the waterflood matures, the fluid produced contains increasing amounts of water and decreasing amounts of oil. Surface equipment is used to separate the oil from the water, with the oil going to holding tanks for sale and the water being recycled to the injection facilities. In the Black Oaks Project, we realized an initial increase of approximately 20 barrels per day in oil production as a result of the waterflood pilot program.

In addition, we may utilize 3-D seismic analysis, horizontal drilling, and other technologies and production techniques to improve drilling results and ultimately enhance our production and returns. We also believe use of such technologies and production techniques in exploring for, developing and exploiting oil and natural gas properties will help us reduce drilling risks, lower finding costs and provide for more efficient production of oil and natural gas from our properties.

Markets and Marketing

The natural gas and oil industry has experienced dramatic price volatility in recent years, and especially in recent months. As a commodity, global natural gas and oil prices respond to macro-economic factors affecting supply and demand. In particular, world oil prices have risen and fallen in response to political unrest and supply uncertainty in the United States, Iraq, Venezuela, Nigeria, Russia and Iran, and changing demand for energy in rapidly growing economies, notably India and China. North American prospects have become more attractive as efforts to stimulate the US economy and reduce dependence on foreign oil increase. Escalating conflicts in the Middle East and the ability of OPEC to control supply and pricing are some of the factors impacting the availability of global supply. The costs of steel and other products used to construct drilling rigs and pipeline infrastructure, as well as drilling and well-servicing rig rates, are impacted by the commodity price volatility.

Our market is affected by many factors beyond our control, such as the availability of other domestic production, commodity prices, the proximity and capacity of natural gas and oil pipelines, and general fluctuations of global and domestic supply and demand. We have entered into two sales contracts (with Shell and BP) at this time, and we do not anticipate difficulty in finding additional sales opportunities, as and when needed.

Natural gas and oil sales prices are negotiated based on factors such as the spot price for natural gas or posted price for oil, price regulations, regional price variations, hydrocarbon quality, distances from wells to pipelines, well pressure, and estimated reserves. Many of these factors are outside our control. Natural gas and oil prices have historically experienced high volatility, related in part to ever-changing perceptions within the industry of future supply and demand.

Competition

The natural gas and oil industry is intensely competitive and we must compete against larger companies that may have greater financial and technical resources than we do and substantially more experience in our industry. These competitive advantages may better enable our competitors to sustain the impact of higher exploration and production costs, natural gas and oil price volatility, productivity variances between properties, overall industry cycles and other factors related to our industry. Their advantage may also negatively impact our ability to acquire prospective properties, develop reserves, attract and retain quality personnel and raise capital.

Research and Development Activities

We have not spent any material amount of time in the last two fiscal years on research and development activities.

Governmental Regulations

Regulation of Oil and Natural Gas Production. Our oil and natural gas exploration, production and related operations, when developed, are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, some states in which we may operate, including Kansas, require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. Failure to comply with any such rules and regulations can result in substantial penalties. Moreover, such states may place burdens from previous operations on current lease owners, and the burdens could be significant. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations.

Federal Regulation of Natural Gas. The Federal Energy Regulatory Commission ("FERC") regulates interstate natural gas transportation rates and service conditions, which may affect the marketing of natural gas produced by us, as well as the revenues that may be received by us for sales of such production. Since the mid-1980's, FERC has issued a series of orders, culminating in Order Nos. 636, 636-A and 636-B ("Order 636"), that have significantly altered the marketing and transportation of natural gas. Order 636 mandated a fundamental restructuring of interstate pipeline sales and transportation service, including the unbundling by interstate pipelines of the sale, transportation, storage and other components of the city-gate sales services such pipelines previously performed. One of FERC's purposes in issuing the order was to increase competition within all phases of the natural gas industry. The United States Court of Appeals for the District of Columbia Circuit largely upheld Order 636 and the Supreme Court has declined to hear the appeal from that decision. Generally, Order 636 has eliminated or substantially reduced the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation service, and has substantially increased competition and volatility in natural gas markets.

The price we may receive from the sale of oil and natural gas liquids will be affected by the cost of transporting products to markets. Effective January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil pipelines, which, generally, would index such rates to inflation, subject to certain conditions and limitations. We are not able to predict with certainty the effect, if any, of these regulations on our intended operations. However, the regulations may increase transportation costs or reduce well head prices for oil and natural gas liquids.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue.

These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;

- limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and

- impose substantial liabilities for pollution resulting from its operations, or due to previous operations conducted on any leased lands.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act, as amended ("CERCLA"), and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. It is not uncommon for the neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes govern the disposal of "solid waste" and "hazardous waste" and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements.

The Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act"), and analogous state laws impose restrictions and controls on the discharge of pollutants into federal and state waters. These laws also regulate the discharge of storm water in process areas. Pursuant to these laws and regulations, we are required to obtain and maintain approvals or permits for the discharge of wastewater and storm water and develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans," in connection with on-site storage of greater than threshold quantities of oil. The EPA issued revised SPCC rules in July 2002 whereby SPCC plans are subject to more rigorous review and certification procedures. We believe that our operations are in substantial compliance with applicable Clean Water Act and analogous state requirements, including those relating to wastewater and storm water discharges and SPCC plans.

The Endangered Species Act, as amended ("ESA"), seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of the Act. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations will be in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject us to significant expenses to modify our operations or could force us to discontinue certain operations altogether.

Personnel

As of March 31, 2009, we had 14 full-time employees, an increase from 9 full time employees at our fiscal year ended March 31, 2008. We hired a number of former independent field contractors to help secure a more stable work base during the months where extremely high oil prices could have limited our access to products and services needed to develop and operate our properties. Since November 2008, we have reduced personnel levels by 5 full time employees and one independent contractor in response to declining economic conditions and in an effort to reduce our operating and general expenses, and cash outlay. As production and drilling activities increase or decrease, we may have to adjust our technical, operational and administrative personnel as appropriate. We are using and will continue to use independent consultants and contractors to perform various professional services, particularly in the area of land services, reservoir engineering, geology drilling, water hauling, pipeline construction, well design, well-site monitoring and surveillance, permitting and environmental assessment. We believe that this use of third-party service providers may enhance our ability to contain operating and general expenses, and capital costs.

Facilities

We currently lease our executive offices at 27 Corporate Woods, Suite 350, 10975 Grandview Drive, Overland Park, Kansas 66210, which expires in September 30, 2013. Future minimum payments are $71,180 for the year ending March 31, 2010.

GLOSSARY

Term	Definition
Barrel (bbl)	The standard unit of measurement of liquids in the petroleum industry, it contains 42 U.S. standard gallons. Abbreviated to “bbl”.
Basin	A depression in the crust of the Earth, caused by plate tectonic activity and subsidence, in which sediments accumulate. Sedimentary basins vary from bowl-shaped to elongated troughs. Basins can be bounded by faults. Rift basins are commonly symmetrical; basins along continental margins tend to be asymmetrical. If rich hydrocarbon source rocks occur in combination with appropriate depth and duration of burial, then a petroleum system can develop within the basin.
BOPD	Abbreviation for barrels of oil per day, a common unit of measurement for volume of crude oil. The volume of a barrel is equivalent to 42 U.S. standard gallons.
Carried Working Interest	The owner of this type of working interest in the drilling of a well incurs no capital contribution requirement for drilling or completion costs associated with a well and, if specified in the particular contract, may not incur capital contribution requirements beyond the completion of the well.
Completion / Completing	A well made ready to produce oil or natural gas.
Development	The phase in which a proven oil or natural gas field is brought into production by drilling development wells.
Development Drilling	Wells drilled during the Development phase.
Division order	A directive signed by the royalty owners verifying to the purchaser or operator of a well the decimal interest of production owned by the royalty owner. The Division Order generally includes the decimal interest, a legal description of the property, the operator’s name, and several legal agreements associated with the process. Completion of this step generally precedes placing the royalty owner on pay status to begin receiving revenue payments.
Drilling	Act of boring a hole through which oil and/or natural gas may be produced.
Dry Wells	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
Exploration	The phase of operations which covers the search for oil or natural gas generally in unproven or semi-proven territory.

Exploratory Drilling	Drilling of a relatively high percentage of properties which are unproven.
Farm out	An arrangement whereby the owner of a lease assigns all or some portion of the lease or licenses to another company for undertaking exploration or development activity.
Field	An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.
Fixed price swap	A derivative instrument that exchanges or "swaps" the "floating" or daily price of a specified volume of natural gas, oil or NGL, over a specified period, for a fixed price for the specified volume over the same period (typically three months or longer).
Gathering line / system	Pipelines and other facilities that transport oil or natural gas from wells and bring it by separate and individual lines to a central delivery point for delivery into a transmission line or mainline.
Gross acre	The number of acres in which the Company owns any working interest.
Gross Producing Well	A well in which a working interest is owned and is producing oil or natural gas or other liquids or hydrocarbons. The number of gross producing wells is the total number of wells producing oil or natural gas or other liquids or hydrocarbons in which a working interest is owned.
Gross well	A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.
Held-By-Production (HBP)	Refers to an oil and natural gas property under lease, in which the lease continues to be in force, because of production from the property.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then turned and drilled horizontally. Horizontal drilling allows the wellbore to follow the desired formation.
In-fill wells	In-fill wells refers to wells drilled between established producing wells; a drilling program to reduce the spacing between wells in order to increase production and recovery of in-place hydrocarbons.
Oil and Natural Gas Lease	A legal instrument executed by a mineral owner granting the right to another to explore, drill, and produce subsurface oil and natural gas. An oil and natural gas lease embodies the legal rights, privileges and duties pertaining to the lessor and lessee.
Lifting Costs	The expenses of producing oil from a well. Lifting costs are the operating costs of the wells including the gathering and separating equipment. Lifting costs do not include the costs of drilling and completing the wells or transporting the oil.

Mcf	Thousand cubic feet.
Mmcf	Million cubic feet.
Net acres	Determined by multiplying gross acres by the working interest that the Company owns in such acres.
Net Producing Wells	The number of producing wells multiplied by the working interest in such wells.
Net Revenue Interest	A share of production revenues after all royalties, overriding royalties and other nonoperating interests have been taken out of production for a well(s).
Operator	A person, acting for itself, or as an agent for others, designated to conduct the operations on its or the joint interest owners' behalf.
Overriding Royalty	Ownership in a percentage of production or production revenues, free of the cost of production, created by the lessee, company and/or working interest owner and paid by the lessee, company and/or working interest owner out of revenue from the well.
Pooled Unit	A term frequently used interchangeably with "Unitization" but more properly used to denominate the bringing together of small tracts sufficient for the granting of a well permit under applicable spacing rules.
Proved Developed Reserves	Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. This definition of proved developed reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.
Proved Developed Non-Producing	Proved developed reserves expected to be recovered from zones behind casings in existing wells.
Proved Undeveloped Reserves	Proved undeveloped reserves are the portion of proved reserves which can be expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for completion. This definition of proved undeveloped reserves has been abbreviated from the applicable definitions contained in Rule 4-10(a)(2-4) of Regulation S-X.
PV10	PV10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV10 is a non-GAAP financial measure. See "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" on page 57 for a reconciliation to the comparable GAAP financial measure.

Re-completion	Completion of an existing well for production from one formation or reservoir to another formation or reservoir that exists behind casing of the same well.
Reservoir	The underground rock formation where oil and natural gas has accumulated. It consists of a porous rock to hold the oil or natural gas, and a cap rock that prevents its escape.
Reservoir Pressure	The pressure at the face of the producing formation when the well is shut-in. It equals the shut-in pressure at the wellhead plus the weight of the column of oil and natural gas in the well.
Roll-Up Strategy	A "roll-up strategy" is a common business term used to describe a business plan whereby a company accumulates multiple small operators in a particular business sector with a goal to generate synergies, stimulate growth and optimize the value of the individual pieces.
Secondary Recovery	The stage of hydrocarbon production during which an external fluid such as water or natural gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore.
	The most common secondary recovery techniques are natural gas injection and waterflooding. Normally, natural gas is injected into the natural gas cap and water is injected into the production zone to sweep oil from the reservoir. A pressure-maintenance program can begin during the primary recovery stage, but it is a form of enhanced recovery.
Shut-in well	A well which is capable of producing but is not presently producing. Reasons for a well being shut-in may be lack of equipment, market or other.
Stock Tank Barrel or STB	A stock tank barrel of oil is the equivalent of 42 U.S. Gallons at 60 degrees Fahrenheit.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Unitize, Unitization	When owners of oil and/or natural gas reservoir pool their individual interests in return for an interest in the overall unit.
Waterflood	The injection of water into an oil reservoir to "push" additional oil out of the reservoir rock and into the wellbores of producing wells. Typically a secondary recovery process.
Water Injection Wells	A well in which fluids are injected rather than produced, the primary objective typically being to maintain or increase reservoir pressure, often pursuant to a waterflood.

Water Supply Wells	A well in which fluids are being produced for use in a Water Injection Well.
Wellbore	A borehole; the hole drilled by the bit. A wellbore may have casing in it or it may be open (uncased); or part of it may be cased, and part of it may be open. Also called a borehole or hole.
Working Interest	An interest in an oil and natural gas lease entitling the owner to receive a specified percentage of the proceeds of the sale of oil and natural gas production or a percentage of the production, but requiring the owner of the working interest to bear the cost to explore for, develop and produce such oil and natural gas.

ITEM 1A. RISK FACTORS.

Declining economic conditions could negatively impact our business

Our operations are affected by local, national and worldwide economic conditions. Markets in the United States and elsewhere have been experiencing extreme volatility and disruption for more than 12 months, due in part to the financial stresses affecting the liquidity of the banking system and the financial markets generally. In recent months, this volatility and disruption has reached unprecedented levels. The consequences of a potential or prolonged recession may include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. While the ultimate outcome and impact of the current economic conditions cannot be predicted, a lower level of economic activity might result in a decline in energy consumption, which may materially adversely affect the price of oil, our revenues, liquidity and future growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and our ability to raise capital.

We have sustained losses, which raises doubt as to our ability to successfully develop profitable business operations.

Our prospects must be considered in light of the risks, expenses and difficulties frequently encountered in establishing and maintaining a business in the oil and natural gas industries. There is nothing conclusive at this time on which to base an assumption that our business operations will prove to be successful or that we will be able to operate profitably. Our future operating results will depend on many factors, including:

- the future prices of natural gas and oil;
- our ability to raise adequate working capital;
- success of our development and exploration efforts;
- demand for natural gas and oil;
- the level of our competition;
- our ability to attract and maintain key management, employees and operators;
- transportation and processing fees on our facilities;
- fuel conservation measures;
- alternate fuel requirements or advancements;
- government regulation and taxation;
- technical advances in fuel economy and energy generation devices; and
- our ability to efficiently explore, develop and produce sufficient quantities of marketable natural gas or oil in a highly competitive and speculative environment while maintaining quality and controlling costs.

To achieve profitable operations, we must, alone or with others, successfully execute on the factors stated above, along with continually developing ways to enhance our production efforts. Despite our best efforts, we may not be successful in our development efforts or obtain required regulatory approvals. There is a possibility that some of our wells may never produce natural gas or oil in sustainable or economic quantities.

We will need additional capital in the future to finance our planned growth, which we may not be able to raise or may only be available on terms unfavorable to us or our stockholders, which may result in our inability to fund our working capital requirements and harm our operational results.

We have and expect to continue to have substantial capital expenditure and working capital needs. We will need to rely on cash flow from operations and borrowings under our Credit Facility or raise additional cash to fund our operations, pay outstanding long-term debt, fund our anticipated reserve replacement needs and implement our growth strategy, or respond to competitive pressures and/or perceived opportunities, such as investment, acquisition, exploration, work-over and development activities.

If low natural gas and oil prices, operating difficulties, constrained capital sources or other factors, many of which are beyond our control, cause our revenues or cash flows from operations to decrease, we may be limited in our ability to spend the capital necessary to complete our development, production exploitation and exploration programs. If our resources or cash flows do not satisfy our operational needs, we will require additional financing, in addition to anticipated cash generated from our operations, to fund our planned growth. Additional financing might not be available on terms favorable to us, or at all. If adequate funds were not available or were not available on acceptable terms, our ability to fund our operations, take advantage of opportunities, develop or enhance our business or otherwise respond to competitive pressures would be significantly limited. In such a capital restricted situation, we may curtail our acquisition, drilling, development, and exploration activities or be forced to sell some of our assets on an untimely or unfavorable basis. Our current plans to address lower crude and natural gas prices are primarily to reduce both capital and operating expenditures to a level equal to or below cash flow from operations. However, our plans may not be successful in improving our results of operations and liquidity.

If we raise additional funds through the issuance of equity or convertible debt securities, the percentage ownership of our stockholders would be reduced, and these newly issued securities might have rights, preferences or privileges senior to those of existing stockholders.

Our auditor's report reflects the fact that without realization of additional capital, it would be unlikely for us to continue as a going concern.

As a result of our deficiency in working capital at March 31, 2009 and other factors, our auditors have included a paragraph in their audit report regarding substantial doubt about our ability to continue as a going concern. Our plans in this regard are to increase production, seek strategic alternatives and to seek additional capital through future equity private placements or debt facilities.

Natural gas and oil prices are volatile. This volatility may occur in the future, causing negative change in cash flows which may result in our inability to cover our operating or capital expenditures.

Our future revenues, profitability, future growth and the carrying value of our properties is anticipated to depend substantially on the prices we may realize for our natural gas and oil production. Our realized prices may also affect the amount of cash flow available for operating or capital expenditures and our ability to borrow and raise additional capital.

Natural gas and oil prices are subject to wide fluctuations in response to relatively minor changes in or perceptions regarding supply and demand. Historically, the markets for natural gas and oil have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause this volatility are:

- local, national and worldwide economic conditions;
- worldwide or regional demand for energy, which is affected by economic conditions;
- the domestic and foreign supply of natural gas and oil;
- weather conditions;
- natural disasters;
- acts of terrorism;
- domestic and foreign governmental regulations and taxation;
- political and economic conditions in oil and natural gas producing countries, including those in the Middle East and South America;
- impact of the U.S. dollar exchange rates on oil and natural gas prices;
- the availability of refining capacity;
- actions of the Organization of Petroleum Exporting Countries, or OPEC, and other state controlled oil companies relating to oil price and production controls; and
- the price and availability of other fuels.

It is impossible to predict natural gas and oil price movements with certainty. Lower natural gas and oil prices may not only decrease our future revenues on a per unit basis but also may reduce the amount of natural gas and oil that we can produce economically. A substantial or extended decline in natural gas and oil prices may materially and adversely affect our future business enough to force us to cease our business operations. In addition, our reserves, financial condition, results of operations, liquidity and ability to finance and execute planned capital expenditures will also suffer in such a price decline. Further, natural gas and oil prices do not necessarily move together.

Approximately 68% of our total proved reserves as of March 31, 2009 consist of undeveloped and developed non-producing reserves, and those reserves may not ultimately be developed or produced.

Our estimated total proved PV 10 (present value) before tax of reserves as of March 31, 2009 was $10.63 million, versus $39.6 million as of March 31, 2008. The decline in PV10 is primarily due to the estimated average price of oil at March 31, 2009 of $42.65 versus $94.53 at March 31, 2008. We developed total proved reserves to 1.3 million barrels of oil equivalent, or BOE, as of March 31, 2009. Of the 1.3 million BOE of total proved reserves, approximately 39% are proved developed and approximately 61% are proved undeveloped. The proved developed reserves consist of 82% proved developed producing reserves and 18% proved developed non-producing reserves. See "Glossary" on page 23 for our definition of PV10.

As of March 31, 2009, approximately 61% of our total proved reserves were undeveloped and approximately 7% were developed non-producing. We plan to develop and produce all of our proved reserves, but ultimately some of these reserves may not be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced in the time periods we have planned, at the costs we have budgeted, or at all.

Because we face uncertainties in estimating proven recoverable reserves, you should not place undue reliance on such reserve information.

Our reserve estimate and the future net cash flows attributable to those reserves at March 31, 2009 was prepared by Miller and Lents, Ltd., an independent petroleum consultant. Prior to this fiscal year, our reserves were evaluated and estimates were prepared by McCune Engineering, an independent petroleum and geological engineer. There are numerous uncertainties inherent in estimating quantities of proved reserves and cash flows from such reserves, including factors beyond our control and the control of these independent consultants and engineers. Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that can be economically extracted, which cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to these reserves, is a function of the available data, assumptions regarding future natural gas and oil prices, expenditures for future development and exploitation activities, and engineering and geological interpretation and judgment. Reserves and future cash flows may also be subject to material downward or upward revisions based upon production history, development and exploitation activities and natural gas and oil prices. Actual future production, revenue, taxes, development expenditures, operating expenses, quantities of recoverable reserves and value of cash flows from those reserves may vary significantly from the assumptions and estimates in our reserve reports. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas and oil attributable to any particular group of properties, the classification of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, reserve engineers may make different estimates of reserves and cash flows based on the same available data. The estimated quantities of proved reserves and the discounted present value of future net cash flows attributable to those reserves included in this report were prepared by Miller and Lents, Ltd. in accordance with rules of the Securities and Exchange Commission, or SEC, and are not intended to represent the fair market value of such reserves.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. We base the estimated discounted future net cash flows from our proved reserves on prices and costs. However, actual future net cash flows from our natural gas and oil properties also will be affected by factors such as:

- geological conditions;
- assumptions governing future oil and natural gas prices;
- amount and timing of actual production;
- availability of funds;
- future operating and development costs;

- actual prices we receive for natural gas and oil;
- supply and demand for our natural gas and oil;
- changes in government regulations and taxation; and
- capital costs of drilling new wells.

The timing of both our production and our incurrence of expenses in connection with the development and production of our properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our business or the natural gas and oil industry in general.

Currently, The SEC permits natural gas and oil companies, in their public filings, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. These current SEC guidelines strictly prohibit us from including "probable reserves" and "possible reserves" in such filings. Effective January 1, 2010, however, the SEC is adopting revisions to its oil and gas reporting disclosures which are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, which should help investors evaluate the relative value of oil and gas companies. Oil and gas companies will be permitted, but not required, to disclose probable reserves (i.e., reserves less likely to be recovered than proved reserves, but as likely as not to be recovered) and possible reserves (i.e., reserves less certain to be recovered than probable reserves).We also caution you that the SEC has, in the past, viewed such probable and possible reserve estimates as inherently unreliable and these estimates may be seen as misleading to investors unless the reader is an expert in the natural gas and oil industry. Unless you have such expertise, you should not place undue reliance on these estimates. Potential investors should also be aware that such "probable" and "possible" reserve estimates will not be contained in any filing with the SEC, any "resale" or other registration statement filed by us that offers or sells shares on behalf of purchasers of our common stock and may have an impact on the valuation of the resale of the shares until permitted by SEC rules. Except as required by applicable law, we undertake no duty to update this information.

The differential between the New York Mercantile Exchange, or NYMEX, or other benchmark price of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production typically trade at a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark price and the price we receive is called a differential. While we have fixed this differential under the terms of our agreement with Shell through September 31, 2009, the differential on physical sales after that date is still under negotiation. We cannot accurately predict oil and natural gas differentials. In recent years for example, production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity from the Rocky Mountain area, have gradually widened this differential. Recent economic conditions, including volatility in the price of oil and natural gas, have resulted in both increases and decreases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive. These fluctuations could have a material adverse effect on our results of operations, financial condition and cash flows by decreasing the proceeds we receive for our oil and natural gas production in comparison to what we would receive if not for the differential.

The natural gas and oil business involves numerous uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our development, exploitation and exploration activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas and oil well does not ensure a profit on investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their cost, unsuccessful wells can hurt our efforts to replace reserves.

The natural gas and oil business involves a variety of operating risks, including:

- unexpected operational events and/or conditions;
- unusual or unexpected geological formations;
- reductions in natural gas and oil prices;
- limitations in the market for oil and natural gas;
- adverse weather conditions;
- facility or equipment malfunctions;
- title problems;
- natural gas and oil quality issues;
- pipe, casing, cement or pipeline failures;
- natural disasters;
- fires, explosions, blowouts, surface cratering, pollution and other risks or accidents;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- compliance with environmental and other governmental requirements; and
- uncontrollable flows of oil, natural gas or well fluids.

If we experience any of these problems, it could affect well bores, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;

- suspension of our operations; and
- repairs to resume operations.

Because we use third-party drilling contractors to drill our wells, we may not realize the full benefit of worker compensation laws in dealing with their employees. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could impact our operations enough to force us to cease our operations.

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any addition to our production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Developing and exploring for natural gas and oil involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of oilfield equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. Substantially all of our wells drilled through March 31, 2009 have been development wells. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economic. Our initial drilling and development sites, and any potential additional sites that may be developed, require significant additional exploration and development, regulatory approval and commitments of resources prior to commercial development. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

Development of our reserves, when established, may not occur as scheduled and the actual results may not be as anticipated. Drilling activity and lack of access to economically acceptable capital may result in downward adjustments in reserves or higher than anticipated costs. Our estimates will be based on various assumptions, including assumptions over which we have control and assumptions required by the SEC relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. We have control over our operations that affect, among other things, acquisitions and dispositions of properties, availability of funds, use of applicable technologies, hydrocarbon recovery efficiency, drainage volume and production decline rates that are part of these estimates and assumptions and any variance in our operations that affects these items within our control may have a material effect on reserves. The process of estimating our natural gas and oil reserves is extremely complex, and requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Our estimates may not be reliable enough to allow us to be successful in our intended business operations. Our actual production, revenues, taxes, development expenditures and operating expenses will likely vary from those anticipated. These variances may be material.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and income.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may be unable to make such acquisitions because we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them;
- unable to obtain financing for these acquisitions on economically acceptable terms; or
- outbid by competitors.

If we are unable to develop, exploit, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

A significant portion of our potential future reserves and our business plan depend upon secondary recovery techniques to establish production. There are significant risks associated with such techniques.

We anticipate that a significant portion of our future reserves and our business plan will be associated with secondary recovery projects that are either in the early stage of implementation or are scheduled for implementation subject to availability of capital. We anticipate that secondary recovery will affect our reserves and our business plan, and the exact project initiation dates and, by the very nature of waterflood operations, the exact completion dates of such projects are uncertain. In addition, the reserves and our business plan associated with these secondary recovery projects, as with any reserves, are estimates only, as the success of any development project, including these waterflood projects, cannot be ascertained in advance. If we are not successful in developing a significant portion of our reserves associated with secondary recovery methods, then the project may be uneconomic or generate less cash flow and reserves than we had estimated prior to investing the capital. Risks associated with secondary recovery techniques include, but are not limited to, the following:

- higher than projected operating costs;
- lower-than-expected production;

- longer response times;
- higher costs associated with obtaining capital;
- unusual or unexpected geological formations;
- fluctuations in natural gas and oil prices;
- regulatory changes;
- shortages of equipment; and
- lack of technical expertise.

If any of these risks occur, it could adversely affect our financial condition or results of operations.

Any acquisitions we complete are subject to considerable risk.

Even when we make acquisitions that we believe are good for our business, any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- a decrease in our liquidity by using our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage the acquired properties or assets;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;
- unforeseen difficulties encountered in operating in new geographic or geological areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often incomplete or inconclusive.

Our reviews of acquired properties can be inherently incomplete because it is not always feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, plugging or orphaned well liability are not necessarily observable even when an inspection is undertaken.

We must obtain governmental permits and approvals for drilling operations, which can result in delays in our operations, be a costly and time consuming process, and result in restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuances in the region in which we operate. Compliance with the requirements imposed by these authorities can be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations and/or fines. Regulatory or legal actions in the future may materially interfere with our operations or otherwise have a material adverse effect on us. In addition, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that a proposed project may have on the environment, threatened and endangered species, and cultural and archaeological artifacts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

Due to our lack of geographic diversification, adverse developments in our operating areas would materially affect our business.

We currently only lease and operate oil and natural gas properties located in Eastern Kansas. As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of production from these properties caused by significant governmental regulation, transportation capacity constraints, curtailment of production, natural disasters, adverse weather conditions or other events which impact this area.

We depend on a small number of customers for all, or a substantial amount of our sales. If these customers reduce the volumes of oil and natural gas they purchase from us, our revenue and cash available for distribution will decline to the extent we are not able to find new customers for our production.

We have contracted with Shell for the sale of all of our oil through September 2009 and will likely contract for the sale of our natural gas with one, or a small number, of buyers if and when we resume operations on the Gas City Project. It is not likely that there will be a large pool of available purchasers. If a key purchaser were to reduce the volume of oil or natural gas it purchases from us, our revenue and cash available for operations will decline to the extent we are not able to find new customers to purchase our production at equivalent prices.

We are not the operator of some of our properties and we have limited control over the activities on those properties.

We are not the operator on our Black Oaks Project. We have only limited ability to influence or control the operation or future development of the Black Oaks Project or the amount of capital expenditures that we can fund with respect to it. In the case of the Black Oaks Project, our dependence on the operator, Haas Petroleum, limits our ability to influence or control the operation or future development of the project. Such limitations could materially adversely affect the realization of our targeted returns on capital related to exploration, drilling or production activities and lead to unexpected future costs.

We may suffer losses or incur liability for events for which we or the operator of a property have chosen not to obtain insurance.

Our operations are subject to hazards and risks inherent in producing and transporting natural gas and oil, such as fires, natural disasters, explosions, pipeline ruptures, spills, and acts of terrorism, all of which can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our and others' properties. As protection against operating hazards, we maintain insurance coverage against some, but not all, potential losses. In addition, pollution and environmental risks generally are not fully insurable. As a result of market conditions, existing insurance policies may not be renewed and other desirable insurance may not be available on commercially reasonable terms, if at all. The occurrence of an event that is not covered, or not fully covered, by insurance could have a material adverse effect on our business, financial condition and results of operations.

Our hedging activities could result in financial losses or could reduce our available funds or income and therefore adversely affect our financial position.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we have entered into derivative arrangements from April 1, 2008 until December 31, 2013 for between 30 and 130 barrels of oil per day that could result in both realized and unrealized hedging losses. As of March 31, 2009 we had not incurred any such losses. The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we may utilize may be based on posted market prices, which may differ significantly from the actual crude oil, natural gas and NGL prices we realize in our operations.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, while we believe our existing derivative activities are with creditworthy counterparties (Shell and BP), continued deterioration in the credit markets may cause a counterparty not to perform its obligation under the applicable derivative instrument or impact their willingness to enter into future transactions with us.

Our business depends in part on gathering and transportation facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production and could harm our business.

The marketability of our oil and natural gas production will depend in a very large part on the availability, proximity and capacity of pipelines, oil and natural gas gathering systems and processing facilities. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of available capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we will be provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or pipeline capacity could significantly reduce our ability to market our oil and natural gas production and could materially harm our business.

Cost and availability of drilling rigs, equipment, supplies, personnel and other services could adversely affect our ability to execute on a timely basis our development, exploitation and exploration plans.

Shortages or an increase in cost of drilling rigs, equipment, supplies or personnel could delay or interrupt our operations, which could impact our financial condition and results of operations. Drilling activity in the geographic areas in which we conduct drilling activities may increase, which would lead to increases in associated costs, including those related to drilling rigs, equipment, supplies and personnel and the services and products of other vendors to the industry. Increased drilling activity in these areas may also decrease the availability of rigs. Although Haas Petroleum has agreed to provide up to two drilling rigs to the Black Oaks Project when needed, subject to availability of capital, we do not have any contracts for drilling rigs and drilling rigs may not be readily available when we need them. Drilling and other costs may increase further and necessary equipment and services may not be available to us at economical prices.

Our exposure to possible leasehold defects and potential title failure could materially adversely impact our ability to conduct drilling operations.

We obtain the right and access to properties for drilling by obtaining oil and natural gas leases either directly from the hydrocarbon owner, or through a third party that owns the lease. The leases may be taken or assigned to us without title insurance. There is a risk of title failure with respect to such leases, and such title failures could materially adversely impact our business by causing us to be unable to access properties to conduct drilling operations.

Our reserves are subject to the risk of depletion because many of our leases are in mature fields that have produced large quantities of oil and natural gas to date.

Our operations are located in established fields in Eastern Kansas. As a result, many of our leases are in, or directly offset, areas that have produced large quantities of oil and natural gas to date. As such, our reserves may be partially or completely depleted by offsetting wells or previously drilled wells, which could significantly harm our business.

Our lease ownership may be diluted due to financing strategies we may employ in the future due to our lack of capital.

To accelerate our development efforts we plan to take on working interest partners who will contribute to the costs of drilling and completion and then share in revenues derived from production. In addition, we may in the future, due to a lack of capital or other strategic reasons, establish joint venture partnerships or farm out all or part of our development efforts. These economic strategies may have a dilutive effect on our lease ownership and could significantly reduce our operating revenues.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Development, production and sale of natural gas and oil in the United States are subject to extensive laws and regulations, including environmental laws and regulations. We may be required to make large expenditures to comply with environmental and other governmental regulations. Matters subject to regulation include, but are not limited to:

- location and density of wells;
- the handling of drilling fluids and obtaining discharge permits for drilling operations;
- accounting for and payment of royalties on production from state, federal and Indian lands;
- bonds for ownership, development and production of natural gas and oil properties;
- transportation of natural gas and oil by pipelines;
- operation of wells and reports concerning operations; and
- taxation.

Under these laws and regulations, we could be liable for personal injuries, property damage, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that substantially increase our costs. Accordingly, any of these liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations enough to possibly force us to cease our business operations.

Our operations may expose us to significant costs and liabilities with respect to environmental, operational safety and other matters.

We may incur significant costs and liabilities as a result of environmental and safety requirements applicable to our oil and natural gas exploration and production activities. We may also be exposed to the risk of costs associated with Kansas Corporation Commission requirements to plug orphaned and abandoned wells on our oil and natural gas leases from wells previously drilled by third parties. In addition, we may indemnify sellers or lessors of oil and natural gas properties for environmental liabilities they or their predecessors may have created. These costs and liabilities could arise under a wide range of federal, state and local environmental and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs, liens and to a lesser extent, issuance of injunctions to limit or cease operations. In addition, claims for damages to persons or property may result from environmental and other impacts of our operations.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we are not able to recover the resulting costs through insurance or increased revenues, our ability to operate effectively could be adversely affected.

Our facilities and activities could be subject to regulation by the Federal Energy Regulatory Commission or the Department of Transportation, which could take actions that could result in a material adverse effect on our financial condition.

Although it is anticipated that our natural gas gathering systems will be exempt from FERC and DOT regulation, any revisions to this understanding may affect our rights, liabilities, and access to midstream or interstate natural gas transportation, which could have a material adverse effect on our operations and financial condition. In addition, the cost of compliance with any revisions to FERC or DOT rules, regulations or requirements could be substantial and could adversely affect our ability to operate in an economic manner. Additional FERC and DOT rules and legislation pertaining to matters that could affect our operations are considered and adopted from time to time. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures and increased costs.

Although our natural gas sales activities are not currently projected to be subject to rate regulation by FERC, if FERC finds that in connection with making sales in the future, we (i) failed to comply with any applicable FERC administered statutes, rules, regulations or orders, (ii) engaged in certain fraudulent acts, or (iii) engaged in market manipulation, we could be subject to substantial penalties and fines of up to $1.0 million per day per violation.

We operate in a highly competitive environment and our competitors may have greater resources than us.

The natural gas and oil industry is intensely competitive and we compete with other companies, many of which are larger and have greater financial, technological, human and other resources. Many of these companies not only explore for and produce crude oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. Such companies may be able to pay more for productive natural gas and oil properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, such companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. If we are unable to compete, our operating results and financial position may be adversely affected.

We may incur substantial write-downs of the carrying value of our natural gas and oil properties, which would adversely impact our earnings.

We review the carrying value of our natural gas and oil properties under the full-cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, natural gas and oil prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

As previously announced, in December 2008, the Securities and Exchange Commission (“SEC”) issued new regulations for oil and gas reserve reporting which go into effect effective for fiscal years ending on or after December 31, 2009. One of the key elements of the new regulations relate to the commodity prices which are used to calculate reserves and their present value. The new regulations provide for disclosure of oil and gas reserves evaluated using annual average prices based on the prices in effect on the first day of each month rather than the current regulations which utilize commodity prices on the last day of the year.

There was no impairment for the fiscal year ended March 31, 2008. We recorded an impairment of $4,777,723 during the fiscal year ended March 31, 2009 primarily attributable to lower prices for both oil and natural gas at December 31, 2008.

Our success depends on our key management and professional personnel, including C. Stephen Cochennet, the loss of whom would harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of C. Stephen Cochennet, whose knowledge, leadership and technical expertise would be difficult to replace, and on our ability to retain and attract experienced engineers, geoscientists and other technical and professional staff. We have entered into an employment agreement with Mr. Cochennet, and we maintain $1.0 million in key person insurance on Mr. Cochennet. However, if we were to lose his services, our ability to execute our business plan would be harmed and we may be forced to significantly alter our operations until such time as we could hire a suitable replacement for Mr. Cochennet.

Risks Associated with our Debt Financing

Significant and prolonged declines in commodity prices may negatively impact our borrowing base and our ability to borrow overall.

Our borrowing base, which is based on our oil and gas reserves and is subject to review and adjustment on a semi-annual basis and other interim adjustments, has been and may be further reduced when it is reviewed. A reduction in our base results in a "loan excess" which is required to be eliminated through payment of a portion of the loan and/or cash collateralization of Letters of Credit obligations; or adding properties to the borrowing base sufficient to offset the "loan excess". A reduction in our borrowing base or the ability to borrow under our Credit Facility, combined with a reduction in cash flow from operations resulting from a decline in oil prices, may require us to further reduce our capital expenditures and our operating activities.

Until we repay the full amount of our outstanding debentures and Credit Facility, we may continue to have substantial indebtedness, which is secured by substantially all of our assets.

On March 31, 2009, $2.7 million in debentures and approximately $7.3 million of bank loans were outstanding. Under a default situation with respect to the debentures or other secured debt, the lenders may enforce their rights as a secured party and we may lose all or a portion of our assets or be forced to materially reduce our business activities.

Our substantial indebtedness could make it more difficult for us to fulfill our obligations under our Credit Facility and our debentures and, therefore, adversely affect our business.

On July 3, 2008, we entered into a three-year, Senior Secured Credit Facility providing for aggregate borrowings of up to $50 million. As of March 31, 2009, we had total indebtedness of $10.1 million, including $7.328 million of borrowings under the Credit Facility and $2.7 million of remaining debentures, as well as other notes payable totaling approximately $109,000. We had no outstanding letters of credit under the new facility on March 31, 2009. Our substantial indebtedness, and the related interest expense, could have important consequences to us, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our business strategy, or other general corporate purposes;
- being forced to use cash flow to reduce our outstanding balance as a result of an unfavorable borrowing base redetermination;

- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service our indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage as compared to our competitors that have less leverage;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and changes in government regulation;
- limiting our ability to, or increasing the cost of, refinancing our indebtedness; and
- limiting our ability to enter into marketing, hedging, optimization and trading transactions by reducing the number of counterparties with whom we can enter into such transactions as well as the volume of those transactions.

The covenants in our Credit Facility and debentures impose significant operating and financial restrictions on us.

The Credit Facility and our debentures impose significant operating and financial restrictions on us. These restrictions limit our ability and the ability of our subsidiaries, among other things, to:

- incur additional indebtedness and provide additional guarantees;
- pay dividends and make other restricted payments;
- create or permit certain liens;
- use the proceeds from the sales of our oil and natural gas properties;
- use the proceeds from the unwinding of certain financial hedges;
- engage in certain transactions with affiliates; and
- consolidate, merge, sell or transfer all or substantially all of our assets or the assets of our subsidiaries.

The Credit Facility and our debentures also contain various affirmative covenants with which we are required to comply. We obtained a waiver of default from Texas Capital Bank on two technical covenants at March 31, 2009. We are taking steps in an effort to comply with these same covenants in future quarters, including but not limited to, a reduction in principal of approximately $3.3 million with proceeds from liquidating a costless collar we entered into on July 3, 2008 and the reduction of our operating and general expenses. We may be unable to comply with some or all of these covenants in the future as well. If we do not comply with these covenants and are unable to obtain waivers from our lenders, we would be unable to make additional borrowings under these facilities, our indebtedness under these agreements would be in default and could be accelerated by our lenders. In addition, it could cause a cross-default under our other indebtedness, including our debentures. If our indebtedness is accelerated, we may not be able to repay our indebtedness or borrow sufficient funds to refinance it. In addition, if we incur additional indebtedness in the future, we may be subject to additional covenants, which may be more restrictive than those to which we are currently subject.

Risks Associated with our Common Stock

We have the ability to issue additional shares of our common stock and shares of preferred stock without asking for stockholder approval, which could cause your investment to be diluted.

Our Articles of Incorporation authorizes the Board of Directors to issue up to 100,000,000 shares of common stock and 10,000,000 shares of preferred stock. The power of the Board of Directors to issue shares of common stock, preferred stock or warrants or options to purchase shares of common stock or preferred stock is generally not subject to shareholder approval. Accordingly, any additional issuance of our common stock, or preferred stock that may be convertible into common stock, or debt instruments that may be convertible into common or preferred stock, may have the effect of diluting one's investment.

Our common stock is traded on an illiquid market, making it difficult for investors to sell their shares.

Our common stock trades on the Over-the-Counter Bulletin Board under the symbol "ENRJ," but trading has been minimal. Therefore, the market for our common stock is limited. The trading price of our common stock could be subject to wide fluctuations. Investors may not be able to purchase additional shares or sell their shares within the time frame or at a price they desire.

The price of our common stock may be volatile and you may not be able to resell your shares at a favorable price.

Regardless of whether an active trading market for our common stock develops, the market price of our common stock may be volatile and you may not be able to resell your shares at or above the price you paid for such shares. The following factors could affect our stock price:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our financial indicators, such as net income or loss per share, net income or loss and revenues;
- changes in revenue or earnings estimates or publication of research reports by analysts about us or the exploration and production industry;
- potentially limited liquidity;
- actual or anticipated variations in our reserve estimates and quarterly operating results;
- changes in natural gas and oil prices;
- sales of our common stock by significant stockholders and future issuances of our common stock;
- increases in our cost of capital;
- changes in applicable laws or regulations, court rulings and enforcement and legal actions;
- commencement of or involvement in litigation;
- changes in market valuations of similar companies;

- additions or departures of key management personnel;
- general market conditions, including fluctuations in and the occurrence of events or trends affecting the price of natural gas and oil; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

Our articles of incorporation, bylaws and Nevada Law contain provisions that could discourage an acquisition or change of control of us.

Our articles of incorporation authorize our board of directors to issue preferred stock and common stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire control of us. In addition, provisions of the articles of incorporation and bylaws could also make it more difficult for a third party to acquire control of us. In addition, Nevada's "Combination with Interested Stockholders' Statute" and its "Control Share Acquisition Statute" may have the effect in the future of delaying or making it more difficult to effect a change in control of us.

These statutory anti-takeover measures may have certain negative consequences, including an effect on the ability of our stockholders or other individuals to (i) change the composition of the incumbent board of directors; (ii) benefit from certain transactions which are opposed by the incumbent board of directors; and (iii) make a tender offer or attempt to gain control of us, even if such attempt were beneficial to us and our stockholders. Since such measures may also discourage the accumulations of large blocks of our common stock by purchasers whose objective is to seek control of us or have such common stock repurchased by us or other persons at a premium, these measures could also depress the market price of our common stock. Accordingly, our stockholders may be deprived of certain opportunities to realize the "control premium" associated with take-over attempts.

We have no plans to pay dividends on our common stock. You may not receive funds without selling your stock.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements, investment opportunities and restrictions imposed by our debentures and Credit Facility.

We may issue shares of preferred stock with greater rights than our common stock.

Although we have no current plans, arrangements, understandings or agreements to issue any preferred stock, our articles of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our stockholders. Any preferred stock that is issued may rank ahead of our common stock, with respect to dividends, liquidation rights and voting rights, among other things.

We have derivative securities currently outstanding. Exercise of these derivatives will cause dilution to existing and new stockholders.

As of March 31, 2009, we had options and warrants to purchase approximately 438,500 shares of common stock outstanding in addition to 2,500 shares issuable upon conversion of a convertible note. The exercise of our outstanding options and warrants, and the conversion of the note, will cause additional shares of common stock to be issued, resulting in dilution to our existing common stockholders.

Because our common stock is deemed a low-priced "Penny" stock, an investment in our common stock should be considered high risk and subject to marketability restrictions.

Our common stock is currently deemed to be a penny stock, as defined in Rule 3a51-1 under the Securities Exchange Act, which may make it more difficult for investors to liquidate their investment even if and when a market develops for the common stock. Until the trading price of the common stock consistently trades above $5.00 per share, if ever, trading in the common stock may be subject to the penny stock rules of the Securities Exchange Act specified in rules 15g-1 through 15g-10. Those rules require broker-dealers, before effecting transactions in any penny stock, to:

- Deliver to the customer, and obtain a written receipt for, a disclosure document;
- Disclose certain price information about the stock;
- Disclose the amount of compensation received by the broker-dealer or any associated person of the broker-dealer;
- Send monthly statements to customers with market and price information about the penny stock; and
- In some circumstances, approve the purchaser's account under certain standards and deliver written statements to the customer with information specified in the rules.

Consequently, the penny stock rules may restrict the ability or willingness of broker-dealers to sell the common stock and may affect the ability of holders to sell their common stock in the secondary market and the price at which such holders can sell any such securities. These additional procedures could also limit our ability to raise additional capital in the future.

If we fail to remain current on our reporting requirements, we could be removed from the OTC Bulletin Board, which would limit the ability of broker-dealers to sell our securities and the ability of stockholders to sell their securities in the secondary market.

Companies trading on the OTC Bulletin Board, such as us, must be reporting issuers under Section 12 of the Securities Exchange Act of 1934, as amended, and must be current in their reports under Section 13, in order to maintain price quotation privileges on the OTC Bulletin Board. More specifically, FINRA has enacted Rule 6530, which determines eligibility of issuers quoted on the OTC Bulletin Board by requiring an issuer to be current in its filings with the Commission. Pursuant to Rule 6530(e), if we file our reports late with the Commission three times in a two-year period or our securities are removed from the OTC Bulletin Board for failure to timely file twice in a two-year period then we will be ineligible for quotation on the OTC Bulletin Board. As a result, the market liquidity for our securities could be severely adversely affected by limiting the ability of broker-dealers to sell our securities and the ability of stockholders to sell their securities in the secondary market.

FINRA sales practice requirements may limit a stockholder's ability to buy and sell our stock.

In addition to the "penny stock" rules described above, FINRA has adopted rules that require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer's financial status, tax status, investment objectives and other information. Under interpretations of these rules, the FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. The FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit your ability to buy and sell our stock and have an adverse effect on the market for our shares.

Additional Risks and Uncertainties

We are an oil and natural gas acquisition, exploration and development company. If any of the risks that we face actually occur, irrespective of whether those risks are described in this section or elsewhere in this report, our business, financial condition and operating results could be materially adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

Not applicable.

ITEM 3. LEGAL PROCEEDINGS.

We may become involved in various routine legal proceedings incidental to our business. However, to our knowledge as of the date of this report, there are no material pending legal proceedings to which we are a party or to which any of our property is subject.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

We did not submit any matters to a vote of our security holders during the fourth quarter ended March 31, 2009.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

(a) Market Information

PRICE RANGE OF COMMON STOCK

Prior to completion of the reverse merger with Midwest Energy in August of 2006, our common stock was sporadically traded in the inter-dealer markets of the OTC:BB, "pink sheets" and "gray sheets" under the symbol "MPCO." Our common stock currently trades on the OTC:BB under the symbol "ENRJ." Our common stock has traded infrequently on the OTC:BB, which limits our ability to locate accurate high and low bid prices for each quarter within the last two fiscal years. Therefore, the following table lists the quotations for the high and low bid prices as reported by a Quarterly Trade and Quote Summary Report of the OTC Bulletin Board and Yahoo! Finance for fiscal years 2008 and 2009. The quotations reflect inter-dealer prices without retail mark-up, markdown, or commissions and may not represent actual transactions.

	Low	High
Fiscal 2008		
Quarter ended June 30, 2007	1.00	1.25
Quarter ended September 30, 2007	0.75	1.35
Quarter ended December 31, 2007	0.70	1.20
Quarter ended March 31, 2008	0.81	1.20
Fiscal 2009		
Quarter ended June 30, 2008	0.95	1.20
Quarter ended September 30, 2008	4.20	5.00
Quarter ended December 31, 2008	0.45	3.16
Quarter ended March 31, 2009	0.25	1.88

The last reported sale price of our common stock on the OTC:BB was $0.79 per share on July 8, 2009.

(b) Holders of Common Stock

As of July 14, 2009, there were 1,121 holders of record of our common stock.

(c) Dividends

We have never paid or declared any cash dividends on our common stock. We currently intend to retain any future earnings to finance the growth and development of our business and we do not expect to pay any cash dividends on our common stock in the foreseeable future. In addition, we are contractually prohibited by the terms of our outstanding debt from paying cash dividends on our common stock. Payment of future dividends, if any, will be at the discretion of our board of directors and will depend on our financial condition, results of operations, capital requirements, restrictions contained in current or future financing instruments, including the consent of debt holders, if applicable at such time, and other factors our board of directors deems relevant.

(d) Securities Authorized for Issuance under Equity Compensation Plans

2000/2001 Stock Option Plan

The Board of Directors approved the 2000/2001 Stock Option Plan and our stockholders ratified the plan on September 25, 2000. The total number of options that can be granted under the plan is 200,000 shares.

Stock Option Plan

The Board of Directors approved the EnerJex Resources, Inc. Stock Option Plan on August 1, 2002 (the "2002-2003 Stock Option Plan"). Originally, the total number of options that could be granted under the plan was not to exceed 400,000 shares. On May 4, 2007, the Governance, Compensation, and Nominating Committee amended and restated the stock option plan to rename the plan and to increase the number of shares issuable to 1,000,000. Our stockholders approved this plan in September of 2007. In no event may the option price with respect to any stock option granted under the 2002-2003 Stock Option Plan be less than the fair market value of such common stock. However the price of an incentive stock option will not be less than 110% of the fair market value per share on the date of the grant in the case of an individual then owning more than 10% of the total combined voting power of all classes of stock of the corporation.

Each option granted under the 2002-2003 Stock Option Plan will be assigned a time period for exercising not to exceed ten years after the date of the grant. Certain other restrictions will apply in connection with this plan when some awards may be exercised.

In the event of a change of control (as defined in the plan), the date on which all options outstanding under the plan may first be exercised will be accelerated. Generally, all options terminate 90 days after a change of control.

General Terms of Stock Option Plans

Officers (including officers who are members of the board of directors), directors, and other employees and consultants and our subsidiaries (if established) will be eligible to receive options under the stock option plans. The Governance, Compensation and Nominating Committee, or GCNC, of the Board of Directors will administer the stock option plans and will determine those persons to whom options will be granted, the number of options to be granted, the provisions applicable to each grant and the time periods during which the options may be exercised. No options may be granted more than ten years after the date of the adoption of the stock option plans.

Non-qualified stock options will be granted by the committee with an option price equal to the fair market value of the shares of common stock to which the non-qualified stock option relates on the date of grant. The committee may, in its discretion, determine to price the non-qualified option at a different price. In no event may the option price with respect to an incentive stock option granted under the stock option plans be less than the fair market value of such common stock to which the incentive stock option relates on the date the incentive stock option is granted. However the price of an incentive stock option will not be less than 110% of the fair market value per share on the date of the grant in the case of an individual then owning more than 10% of the total combined voting power of all classes of stock of the corporation.

Each option granted under the stock option plans will be exercisable for a term of not more than ten years after the date of grant. Certain other restrictions will apply in connection with the plans when some awards may be exercised. In the event of a change of control (as defined in the stock option plans), the date on which all options outstanding under the stock option plans may first be exercised will be accelerated. Generally, all options terminate 90 days after a change of control.

These plans are intended to encourage directors, officers, employees and consultants to acquire ownership of common stock. The opportunity so provided is intended to foster in participants a strong incentive to put forth maximum effort for our continued success and growth, to aid in retaining individuals who put forth such effort, and to assist in attracting the best available individuals in the future.

Recent Sales of Unregistered Securities

None.

Issuer Purchases of Equity Securities

We did not repurchase any of our equity securities during the fiscal years ended March 31, 2009 or 2008.

ITEM 6. SELECTED FINANCIAL DATA.

Not applicable.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion of our financial condition and results of operations should be read in conjunction with our financial statements and the related notes to our financial statements included elsewhere in this report. In addition to historical financial information, the following discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our actual results and timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under ITEM 1A. Risk Factors and elsewhere in this report.

Overview

Our principal strategy is to focus on the acquisition of oil and natural gas mineral leases that have existing production and cash flow. Once acquired, we strive to implement an accelerated development program utilizing capital resources, a regional operating focus, an experienced management and technical team, and enhanced recovery technologies to attempt to increase production and increase returns for our stockholders. Our oil and natural gas acquisition and development activities are currently focused in Eastern Kansas.

Since the beginning of fiscal 2008 and throughout fiscal 2009, we deployed approximately $12 million in capital resources to acquire and develop five operating projects and drill 179 new wells (111 producing wells, 65 water injection wells, and 3 dry holes). Our estimated total proved PV 10 (present value) of reserves as of March 31, 2009 was $10.63 million, versus $39.6 million as of March 31, 2008. We developed total proved reserves to 1.3 million barrels of oil equivalent, or BOE, as of March 31, 2009. Of the 1.3 million BOE of total proved reserves, approximately 39% are proved developed and approximately 61% are proved undeveloped. The proved developed reserves consist of 82% proved developed producing reserves and 18% proved developed non-producing reserves. See "Glossary" on page 23 for our definition of PV10.

The total proved PV10 (present value) of our reserves as of March 31, 2009 was $10.63 million. PV10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted future net cash flows, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. See "Glossary" on page 24 for our definition of PV10 and "Management's Discussion and Analysis of Financial Condition and Results of Operations-Reserves" page 57, for a reconciliation to the comparable GAAP financial measure.

We are continually evaluating oil and natural gas opportunities in Eastern Kansas and are also in various stages of discussions with potential joint venture ("JV") partners who would contribute capital to develop leases we currently own or would acquire for the JV. We recently entered into one such opportunity on the Brownrigg lease in Linn County, Kansas. This economic strategy will allow us to utilize our own financial assets toward the growth of our leased acreage holdings, pursue the acquisition of strategic oil and natural gas producing properties or companies and generally expand our existing operations while further diversifying risk. Subject to availability of capital, we plan to continue to bring potential acquisition and JV opportunities to various financial partners for evaluation and funding options. It is our vision to grow the business in a disciplined and well-planned manner.

We began generating revenues from the sale of oil during the fiscal year ended March 31, 2008. Subject to availability of capital, we expect our production to continue to increase, both through development of wells, through our acquisition strategy, and other strategic initiatives. Our future financial results will continue to depend on: (i) our ability to source and screen potential projects; (ii) our ability to discover commercial quantities of natural gas and oil; (iii) the market price for oil and natural gas; and (iv) our ability to fully implement our exploration, work-over and development program, which is in part dependent on the availability of capital resources. There can be no assurance that we will be successful in any of these respects, that the prices of oil and natural gas prevailing at the time of production will be at a level allowing for profitable production, or that we will be able to obtain additional funding at terms favorable to us to increase our currently limited capital resources.

The board of directors has implemented a crude oil and natural gas hedging strategy that will allow management to hedge up to 80% of our net production to mitigate a majority of our exposure to changing oil prices in the intermediate term.

Recent Developments

We entered into an agreement with Shell Trading (US) Company, or Shell, whereby we agreed to an 18-month fixed-price swap with Shell for 130 BOPD at a fixed price per barrel of $96.90, before transportation costs from April 1, 2008 through September 30, 2009. This represented approximately 60% of our total oil production on a net revenue basis at that time and locked in approximately $6.8 million in gross revenue before transportation costs over the 18 month period. In addition, we agreed to sell all of our remaining oil production at current spot market pricing beginning April 1, 2008 through September 30, 2009 to Shell. For the fiscal year ended March 31, 2009, the positive impact on our net revenue from the fixed-price swap was approximately $506,000.

On July 3, 2008, EnerJex, EnerJex Kansas, and DD Energy entered into a three-year $50 million Senior Secured Credit Facility (the "Credit Facility") with Texas Capital Bank, N.A. Borrowings under the Credit Facility will be subject to a borrowing base limitation based on our current proved oil and gas reserves and will be subject to semi-annual redeterminations and interim adjustments. The initial borrowing base was set at $10.75 million and was reduced to $7.428 million following the liquidation of the BP hedging instrument in November 2008. The Borrowing Base was reviewed by Texas Capital Bank in February 2009 and it was determined that it should be reduced by $200,000 per month beginning April 2009 and likely continuing through December 2009, primarily as a result of commodity oil prices. The Credit Facility is secured by a lien on substantially all assets of the Company and its subsidiaries. The Credit Facility has a term of three years, and all unpaid principal and interest will be due and payable in full on July 3, 2011. The Credit Facility also provides for the issuance of letters-of-credit up to a $750,000 sub-limit under the borrowing base and up to an additional $2.25 million limit not subject to the borrowing base to support our hedging program. We had borrowings $7.328 million outstanding at March 31, 2009. Subsequent to year-end, we have made Borrowing Base Reduction payments of $200,000.

On July 7, 2008, we amended the $2.7 million of aggregate principal amount of our 10% debentures that remain outstanding to, among other things, permit the indebtedness under our Credit Facility, subordinate the security interests of the debentures to the Credit Facility, provide for the redemption of the remaining debentures with the net proceeds from any next debt or equity offering, eliminate the covenant to maintain certain production thresholds and waive all known defaults. Subsequent to year-end, we again amended the debentures to extend the maturity date to September 30, 2010, and allow us to pay interest in either cash or payment-in-kind interest (an increase in the amount of principal due) or pay interest through the issuance of shares of common stock, and add a provision for the conversion of the debentures into shares of our common stock.

As of July 3, 2008, we entered into an ISDA master agreement and a costless collar with BP Corporation North America Inc., or BP, for 130 barrels of oil per day with a price floor of $132.50 per barrel and a price ceiling of $155.70 per barrel for NYMEX West Texas Intermediate for the period of October 1, 2009 until March 31, 2011. We liquidated this costless collar in November 2008 and received proceeds of approximately $3.9 million from BP. We reduced the debt outstanding under our Credit Facility by approximately $3.3 million and used the remainder for general operating purposes.

On August 1, 2008, we executed three-year employment agreements with C. Stephen Cochennet, our chief executive officer, and Dierdre P. Jones, our chief financial officer. Mr. Cochennet and Ms. Jones have agreed to amend their employment agreements to reflect options rescinded in November 2008.

In February 2009, we entered into a fixed price swap transaction under the terms of the BP ISDA for a total of 120,000 gross barrels at a price of $57.30 per barrel before transportation costs for the period beginning October 1, 2009 and ending on December 31, 2013.

Euramerica failed to fully fund by January 15, 2009 both the balance of the purchase price and the remaining development capital owed under the Amended and Restated Well Development Agreement and Option for “Gas City Property” between us and Euramerica. Therefore, Euramerica has forfeited all of its interest in the property, including all interests in any wells, improvements or assets, and all of Euramerica's interest in the property reverts back to us. In addition, all operating agreements between us and Euramerica relating to the Gas City Project are null and void.

We recorded a non-cash impairment of $4,777,723 to the carrying value of our proved oil and gas properties during the fiscal year ended March 31, 2009. The impairment is primarily attributable to lower prices for both oil and natural gas at December 31, 2008. The charge results from the application of the “ceiling test” under the full cost method of accounting. Under full cost accounting requirements, the carrying value may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. A ceiling test charge occurs when the carrying value of the oil and gas properties exceeds the full cost ceiling.

On March 3, 2009, we withdrew our Form S-1 Registration Statement after deciding to terminate the registered public offering. As global economic conditions deteriorated and the commodity prices of oil and natural gas experienced significant declines, the availability of equity capital became severely constrained. While we intend to return to the equity market when conditions improve and are conducive to raising capital, there can be no assurance that we will be successful in doing so.

On March 23, 2009 we received a Monthly Commitment Notice from Texas Capital Bank requiring a $200,000 Borrowing Base Reduction payment on or before April 1, 2009. This reduction was in response to decreased oil commodity prices. Notices in April, May and June of 2009 called for $200,000 monthly payments as well. We have made three separate $100,000 payments towards that Borrowing Base Reduction request. As of the date of this report, we have not received a default notification from Texas Capital Bank, even though we have paid them less than the amount requested as part of their redetermination. We have been working closely with Texas Capital Bank, as oil commodity prices rebound, and our Independent Reserve Engineers to revalue our reserves in light of commodity prices and improved production levels since Texas Capital's redetermination.

In April and May of 2009, we redeemed $450,000 of the subordinated debentures. The balance remaining as of the date of this report is $2.25 million and these debentures mature on September 30, 2010.

Results of Operations for the Fiscal Years Ended March 31, 2009 and 2008 compared.

We began acquiring oil properties with existing production in April of 2007, the first month of our fiscal year ended March 31, 2008. These acquisitions included the Black Oaks and Thoren Projects. We acquired both the DD Energy and the Tri-County Projects in November of 2007, or about mid-year of that same fiscal year. We owned these projects throughout the entire fiscal year ended March 31, 2009. Comparisons between the fiscal years, then, will reflect a full year of revenues and expenses for all projects for the fiscal year ended March 31, 2009 and a partial year of revenues and expenses for the two of the four projects for the fiscal year ended March 31, 2008.

Income:

	Fiscal Year Ended March 31,		
	2009	2008	Increase / (Decrease)
	Amount	Amount	$
Oil and natural gas revenues	$ 6,436,805	$ 3,602,798	$ 2,834,007

Revenues

Oil and natural gas revenues for the fiscal year ended March 31, 2009 were $6,436,805 compared to revenues of $3,602,798 in the fiscal year ended March 31, 2008. The increase in revenues is primarily the result of the greater oil production levels as well as a higher average price per barrel of oil. The average price per barrel we received for oil sold during the twelve months ended March 31, 2009 was $85.67 compared to $79.71 for the twelve months ended March 31, 2008. Natural gas sales accounted for less than 1% of the total revenues. The average price per Mcf for natural gas sales during the fiscal year ended March 31, 2009 was $5.57, compared to $6.20 during the fiscal year ended March 31, 2008.

Expenses:

	Fiscal Year Ended March 31,		
	2009	**2008**	**Increase / (Decrease)**
	Amount	**Amount**	**$**
Expenses:			
Direct operating costs	$ 2,637,333	$ 1,795,188	$ 842,145
Depreciation, depletion and amortization	872,230	913,224	(40,994)
Total production expenses	3,509,563	2,708,412	801,151
Professional fees	1,320,332	1,226,998	93,334
Salaries	849,340	1,703,099	(853,759)
Depreciation on other fixed assets	39,063	22,106	16,957
Administrative expenses	1,392,645	887,872	504,773
Impairment of oil & gas properties	4,777,723	-	4,777,723
Total expenses	11,888,666	6,548,487	5,340,179

Direct Operating Costs

Direct operating costs for the fiscal year ended March 31, 2009 were $2,637,517 compared to $1,795,188 for the fiscal year ended March 31, 2008. The increase over the prior period results from the operating costs on a greater number of wells on our existing and acquired oil leases during the fiscal year ended March 31, 2009. Direct operating costs include pumping, gauging, pulling, repairs, certain contract labor costs, and other non-capitalized expenses.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for the fiscal year ended March 31, 2009 was $872,230, compared to $913,224 for the fiscal year ended March 31, 2008. The decrease was primarily a result of the lower cost per barrel of depletion of oil reserves. The rate of depletion was $12.02 per barrel for the fiscal year ended March 31, 2009 as compared to $19.57 per barrel for the fiscal year ended March 31, 2008.

Professional Fees

Professional fees for the fiscal year ended March 31, 2009 were $1,320,332 compared to $1,226,998 for the fiscal year ended March 31, 2008. Payments for services rendered in connection with acquisition and financing activities, our audit, legal, and consulting fees are recorded as professional fees and remained relatively constant over the two fiscal years.

Salaries

Salaries for the fiscal year ended March 31, 2009 were $849,340 compared to $1,703,099 for the fiscal year ended March 31, 2008. There were expenses totaling $1,204,102 during the prior fiscal year related to non-cash equity based payments made by issuing stock options to our management. No such issuances were made in the current fiscal year. In addition, the number of full-time employees increased from 9 at March 31, 2008 to 19 at one point during the fiscal year ended March 31, 2009, then settled at 14 on March 31, 2009. As a result, cash based salary expense increased by approximately $500,000 during the current fiscal year.

Depreciation on Other Fixed Assets

Depreciation on other fixed assets fiscal year ended March 31, 2009 was $39,063 compared to $22,106 for the fiscal year ended March 31, 2008. The increase was primarily due to depreciation on fixed assets acquired during the period.

Administrative Expenses

Administrative expenses for the fiscal year ended March 31, 2009 were $1,392,645compared to $887,872 in the fiscal year ended March 31, 2008. The administrative expenses increased in relation to the addition of employees, office space, and corporate activity related to growth in operations.

Impairment of Oil & Gas Properties

The impairment of oil and natural gas properties in the year ended March 31, 2009 of $4,777,723 represented an impairment through applying the full-cost ceiling test method. This ceiling test was applied to all of the cost of our oil and natural gas properties accounted for under the full-cost method that were subject to amortization at March 31, 2009. We took this impairment based on the ceiling test results during the quarter ended December 31, 2008, and was primarily due to depressed commodity prices at the time.

Reserves

Our estimated total proved PV 10 (present value) of reserves as of March 31, 2009 decreased to $10.63 million from $39.6 million as of March 31, 2008. Though total proved reserves were comparable at March 31, 2009 and 2008; 1.3 million and 1.4 million barrels of oil equivalent (BOE), respectively, the PV10 declined dramatically due to the estimated average price of oil at March 31, 2009 of $42.65 versus $94.53 at March 31, 2008. Of the 1.3 million BOE at March 31, 2009 approximately 39% are proved developed and approximately 61% are proved undeveloped. The proved developed reserves consist of proved developed producing (82%) and proved developed non-producing (18%).

The following table presents summary information regarding our estimated net proved reserves as of March 31, 2009. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. The estimates of net proved reserves are based on the reserve reports prepared by Miller and Lents, Ltd., our independent petroleum consultants. For additional information regarding our reserves, please see Note 11 to our audited financial statements as of and for the fiscal year ended March 31, 2009.

Summary of Proved Oil and Natural Gas Reserves
as of March 31, 2009

Proved Reserves Category	Gross	Net	PV10 (before tax)[1]
Proved, Developed Producing			
Oil (stock-tank barrels)	722,590	429,420	$ 6,691,550
Natural Gas (mcf)[2]	-	-	-
Proved, Developed Non-Producing			
Oil (stock-tank barrels)	146,620	95,560	$ 1,459,280
Natural Gas (mcf) [2]	-	-	-
Proved, Undeveloped			
Oil (stock-tank barrels)	1,440,760	811,650	$ 2,478,510
Natural Gas (mcf) [2]	-	-	-
Total Proved Reserves			
Oil (stock-tank barrels)	2,309,970	1,136,630	$ 10,629,340
Natural Gas (mcf) [2]	-	-	-

(1) The following table shows our reconciliation of our PV10 to our standardized measure of discounted future net cash flows (the most direct comparable measure calculated and presented in accordance with GAAP). PV10 is our estimate of the present value of future net revenues from estimated proved natural gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. The estimated future net revenues are discounted at an annual rate of 10% to determine their “present value.” We believe PV10 to be an important measure for evaluating the relative significance of our oil and natural gas properties and that the presentation of the non-GAAP financial measure of PV10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV10 on the same basis. PV10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

	As of March 31, 2009
PV10 (before tax)	$10,629,340
Future income taxes, net of 10% discount	-
Standardized measure of discounted future net cash flows	$10,629,340

(2) There were no natural gas reserves at March 31, 2009.

Liquidity and Capital Resources

Liquidity is a measure of a company’s ability to meet potential cash requirements. We have historically met our capital requirements through debt financing, revenues from operations and the issuance of equity securities. As a result of the $200,000 monthly reduction of our borrowing base beginning April 2009, with the expectation that this monthly reduction would continue through December 2009, we have classified $1.7 million of the borrowings outstanding under our Credit Facility as a current liability. As we may be unable to provide the necessary liquidity we need by the revenues generated from our net interests in our oil and natural gas production at current commodity prices, we are exploring strategic initiative and JV partnerships, as well as sales of reserves in our existing properties to finance our operations and to service our debt obligations.

The following table summarizes total current assets, total current liabilities and working capital at March 31, 2009 as compared to March 31, 2008.

	March 31, 2009	March 31, 2008	Increase / (Decrease) $
Current Assets	$ 898,941	$ 1,511,595	(612,654)
Current Liabilities	$ 2,827,015	$ 2,117,176	709,839
Working Capital (deficit)	$ (1,928,074)	$ (605,581)	(1,322,493)

Senior Secured Credit Facility

On July 3, 2008, EnerJex, EnerJex Kansas, and DD Energy entered into a three-year $50 million Senior Secured Credit Facility (the "Credit Facility") with Texas Capital Bank, N.A. Borrowings under the Credit Facility will be subject to a borrowing base limitation based on our current proved oil and gas reserves and will be subject to semi-annual redeterminations and interim adjustments. The initial borrowing base was set at $10.75 million and was reduced to $7.428 million following the liquidation of the BP hedging instrument in November 2008. The borrowing base was reviewed by Texas Capital Bank in February 2009 and was reduced by $200,000 per month beginning April 2009 with the expectation that this monthly reduction would continue through December 2009. We had borrowings $7.328 million outstanding at March 31, 2009. Subsequent to year-end, we have made $200,000 of Borrowing Base Reduction payments. The Credit Facility is secured by a lien on substantially all assets of the Company and its subsidiaries. The Credit Facility has a term of three years, and matures on July 3, 2011. The Credit Facility also provides for the issuance of letters-of-credit up to a $750,000 sub-limit under the borrowing base and up to an additional $2.25 million limit not subject to the borrowing base to support our hedging program.

Proceeds from the initial extension of credit under the Credit Facility were used: (1) to redeem our 10% Senior Secured Debentures in an aggregate principal amount of $6.3 million plus accrued interest (the "April Debentures"), (2) for Texas Capital Bank's acquisition of the Company's approximately $ 2 million indebtedness to Cornerstone Bank, (3) for complete repayment of promissory notes issued to the sellers in connection with the Company's purchase of the DD Energy project in an aggregate principal amount of $965,000 plus accrued interest, and (4) transaction costs, fees and expenses related to the new facility. Future borrowings may be used for the acquisition, development and exploration of oil and gas properties, capital expenditures and general corporate purposes.

Advances under the Credit Facility will be in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of (1) the lender's "prime rate" and (2) the Federal Funds rate plus a margin of 0.50%, plus a margin of between 0.0% and 0.5% depending on the percent of the borrowing base utilized at the time of the credit extension. The interest rate on the Eurodollar loans fluctuates based upon the British Bankers' Association Interest Settlement Rate appearing on the display designated as page 3750 on Moneyline Telerate, Inc., plus a margin of 2.25% to 2.75% depending on the percent of the borrowing base utilized at the time of the credit extensionon. Eurodollar loans of one, two, three and six months may be selected by the Company. A commitment fee of 0.375% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears.

The Credit Facility includes usual and customary affirmative covenants for credit facilities of this type and size, as well as customary negative covenants, including, among others, limitations on liens, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, and investments. The Credit Facility also requires the Company, at the end of each fiscal quarter beginning with the quarter ending September 30, 2008, to maintain a minimum current assets to current liabilities ratio, and minimum ratios of EBITDA (earnings before interest, taxes, depreciation and amortization) to interest expense and to senior funded debt.

Additionally, Texas Capital Bank, N.A. and the holders of the Senior Secured Debentures entered into a Subordination Agreement whereby the Senior Secured Debentures issued on June 21, 2007 will be subordinated to the Credit Facility.

Debenture Financing.

On April 11, 2007, we completed a $9.0 million private placement of senior secured debentures. In accordance with the terms of the debentures, we received $6.3 million (before expenses and placement fees) at the first closing and an additional $2.7 million (before closing fees and expenses) at the second closing on June 21, 2007. In connection with the sale of the debentures, we issued the lenders 9,000,000 shares of common stock. On July 7, 2008, we redeemed $6.3 million aggregate principal amount of our debentures.

The debentures originally matured on March 31, 2010, absent earlier redemption by us, and carry an interest rate of 10%. Interest on the debentures began accruing on April 11, 2007 and is payable quarterly in arrears on the first day of each succeeding quarter during the term of the debentures, beginning on or about May 11, 2007 and ending on the maturity date of September 30, 2010 - the maturity date was amended subsequent to March 31, 2009 year-end. We may, under certain conditions specified in the debentures, pay interest payments in shares of our registered common stock. Additionally, on the maturity date, we are required to pay the amount equal to the principal, as well as all accrued but unpaid interest.

In connection with the Credit Facility, we entered into an agreement amending the Securities Purchase Agreement, Registration Rights Agreement, the Pledge and Security Agreement and the Senior Secured Debentures issued on June 21, 2007 (the "Debenture Agreements"), with the holders (the "Buyers") of the Senior Secured Debentures issued on June 21, 2007 (the "June Debentures"). Pursuant to this agreement, we, among other things, (i) redeem the April Debentures, (ii) agreed to use the net proceeds from the Company's next debt or equity offering to redeem the June Debentures, (iii) agreed to update the Buyers' registration statements to sell our common stock owned by the Buyers, (iv) amended certain terms of the Debenture Agreements in recognition of the indebtedness under the Credit Facility, (v) amended the Securities Purchase Agreement and Registration Rights Agreement to remove the covenant to issue and register additional shares of common stock in the event that our oil production does not meet certain thresholds over time among other things, and (vi) the Buyers agreed to waive all known events of default. Subsequent to March 31, 2009 year-end, we again amended the debentures to extend the maturity date to September 30, 2010, and allow us to pay interest in either cash or payment-in-kind interest (an increase in the amount of principal due) or payment-in-kind shares (issuance of shares of common stock), and add a provision for the conversion of the debentures into shares of EnerJex's common stock.

Going Concern

Our accompanying consolidated financial statements have been prepared assuming that we will continue as a going concern. Our ability to continue as a going concern is dependent upon attaining profitable operations based on increased production and prices of oil and natural gas. We intend to use borrowings, equity and asset sales, and other strategic initiatives to mitigate the effects of our cash position, however, no assurance can be given that debt or equity financing, if and when required, will be available. The financial statements do not include any adjustments relating to the recoverability and classification of recorded assets and classification of liabilities that might be necessary should we be unable to continue in existence.

Satisfaction of our cash obligations for the next 12 months.

A critical component of our operating plan is the ability to obtain additional capital through additional equity and/or debt financing and working interest participants. During fiscal 2009, we were in the midst of a public equity offering when global economic conditions deteriorated and the commodity prices of oil and natural gas experienced significant declines. Our cash revenues from operations have been significantly impacted as has our ability to meet our monthly operating expenses and service our debt obligations. In the event we cannot obtain additional capital through other means to allow us to pursue our strategic plan, this would materially impact our ability to continue our desired growth. There is no assurance we would be able to obtain such financing on commercially reasonable terms, if at all.

We intend to implement and execute our business and marketing strategy, respond to competitive developments, and attract, retain and motivate qualified personnel. There can be no assurance that we will be successful in addressing such risks, and the failure to do so can have a material adverse effect on our business prospects, financial condition and results of operations.

Summary of product research and development that we will perform for the term of our plan.

We do not anticipate performing any significant product research and development under our plan of operation until such time as we can raise adequate working capital to sustain our operations.

Expected purchase or sale of any significant equipment.

We anticipate that we will purchase the necessary production and field service equipment required to produce oil and natural gas during our normal course of operations over the next twelve months.

Significant changes in the number of employees.

As of March 31, 2009, we had 14 full-time employees, an increase from 9 full time employees at our fiscal year ended March 31, 2008. We hired a number of former independent field contractors to help secure a more stable work base during the months where extremely high oil prices could have limited our access to products and services needed to develop and operate our properties. Since November 2008, we have reduced personnel levels by 5 full time employees and one independent contractor in response to declining economic conditions and in an effort to reduce our operating and general expenses and cash outlay. As drilling production activities increase or decrease, we may have to adjust our technical, operational and administrative personnel as appropriate. We are using and will continue to use the services of independent consultants and contractors to perform various professional services, particularly in the area of land services, reservoir engineering, geology drilling, water hauling, pipeline construction, well design, well-site monitoring and surveillance, permitting and environmental assessment. We believe that this use of third-party service providers may enhance our ability to contain operating and general expenses, and capital costs.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Critical Accounting Policies and Estimates

Our critical accounting estimates include our oil and gas properties, asset retirement obligations and the value of share-based payments.

Oil and Gas Properties:

The accounting for our business is subject to special accounting rules that are unique to the gas and oil industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full-cost method. We follow the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved gas and oil reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are assessed individually when individual costs are significant.

We review the carrying value of our gas and oil properties under the full-cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, gas and oil prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

The process of estimating gas and oil reserves is very complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates.

As of March 31, 2009, approximately 100% of our proved reserves were evaluated by an independent petroleum consultant. All reserve estimates are prepared based upon a review of production histories and other geologic, economic, ownership and engineering data.

Asset Retirement Obligations:

The asset retirement obligation relates to the plug and abandonment costs when our wells are no longer useful. We determine the value of the liability by obtaining quotes for this service and estimate the increase we will face in the future. We then discount the future value based on an intrinsic interest rate that is appropriate for us. If costs rise more than what we have expected there could be additional charges in the future however we monitor the costs of the abandoned wells and we will adjust this liability if necessary.

Share-Based Payments:

The value we assign to the options and warrants that we issue is based on the fair market value as calculated by the Black-Scholes pricing model. To perform a calculation of the value of our options and warrants, we determine an estimate of the volatility of our stock. We need to estimate volatility because there has not been enough trading of our stock to determine an appropriate measure of volatility. We believe our estimate of volatility is reasonable, and we review the assumptions used to determine this whenever we issue a new equity instruments. If we have a material error in our estimate of the volatility of our stock, our expenses could be understated or overstated.

Recent Issued Accounting Standards

In May 2008, the Financial Accounting Standards Board (“FASB”) issued SFAS No. 163, “*Accounting for Financial Guarantee Insurance Contracts – An interpretation of FASB Statement No. 60*”. SFAS No. 163 requires that an insurance enterprise recognize a claim liability prior to an event of default when there is evidence that credit deterioration has occurred in an insured financial obligation. It also clarifies how Statement 60 applies to financial guarantee insurance contracts, including the recognition and measurement to be used to account for premium revenue and claim liabilities, and requires expanded disclosures about financial guarantee insurance contracts. It is effective for financial statements issued for fiscal years beginning after December 15, 2008, except for some disclosures about the insurance enterprise’s risk-management activities. SFAS No. 163 requires that disclosures about the risk-management activities of the insurance enterprise be effective for the first period beginning after issuance. Except for those disclosures, earlier application is not permitted. The adoption of this statement is not expected to have a material effect on the Company’s financial statements.

In May 2008, the FASB issued SFAS No. 162, “*The Hierarchy of Generally Accepted Accounting Principles*”. SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. It is effective 60 days following the SEC’s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, “*The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles*”. The adoption of this statement is not expected to have a material effect on the Company’s financial statements.

In March 2008, the Financial Accounting Standards Board ("FASB") issued SFAS No. 161, "*Disclosures about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133*". SFAS No. 161 is intended to improve financial standards for 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. Entities are required to provide enhanced disclosures about: (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. It is effective for financial statements issued for fiscal years beginning after November 15, 2008, with early adoption encouraged. The Company is currently evaluating the impact of SFAS No. 161 on its financial statements, and the adoption of this statement is not expected to have a material effect on the Company's financial statements.

In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141 (revised 2007), "Business Combinations". This statement replaces SFAS No. 141 and defines the acquirer in a business combination as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. SFAS 141 (revised 2007) requires an acquirer to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquired at the acquisition date, measured at their fair values as of that date. SFAS 141 (revised 2007) also requires the acquirer to recognize contingent consideration at the acquisition date, measured at its fair value at that date. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. The adoption of this statement is not expected to have a material effect on the Company's financial statements.

In December 2007, the FASB issued SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements Liabilities –an Amendment of ARB No. 51". This statement amends ARB 51 to establish accounting and reporting standards for the Non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. The adoption of this statement is not expected to have a material effect on the Company's financial statements.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Material changes in prices impact revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. We anticipate business costs and the demand for services related to production and exploration will fluctuate while the commodity prices for oil and natural gas, both remain volatile.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Management Responsibility for Financial Information

We are responsible for the preparation, integrity and fair presentation of our financial statements and the other information that appears in this annual report on Form 10-K. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States and include estimates based on our best judgment.

We maintain a comprehensive system of internal controls and procedures designed to provide reasonable assurance, at an appropriate cost-benefit relationship, that our financial information is accurate and reliable, our assets are safeguarded and our transactions are executed in accordance with established procedures.

Weaver & Martin, LLC, an independent registered public accounting firm, is retained to audit our consolidated financial statements. Its accompanying report is based on audits conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States).

The Audit Committee, which is comprised of two independent directors, meets with our management and the independent registered public accounting firm to ensure that each is properly fulfilling its responsibilities. The Committee oversees our systems of internal control, accounting practices, financial reporting and audits to ensure their quality, integrity and objectivity are sufficient to protect stockholders' investments.

Our consolidated financial statements and notes thereto, and other information required by this Item 8 are included in this report beginning on page F-1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A(T). CONTROLS AND PROCEDURES.

Our Chief Executive Officer, C. Stephen Cochennet, and our Chief Financial Officer, Dierdre P. Jones, evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) as of the end of the period covered by this Report. Based on the evaluation, Mr. Cochennet and Ms. Jones concluded that our disclosure controls and procedures are effective in timely alerting them to material information relating to us (including our consolidated subsidiaries) required to be included in our periodic SEC filings.

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

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as is defined in the Securities Exchange Act of 1934. These internal controls are designed to provide reasonable assurance that the reported financial information is presented fairly, that disclosures are adequate and that the judgments inherent in the preparation of financial statements are reasonable. There are inherent limitations in the effectiveness of any system of internal control, including the possibility of human error and overriding of controls. Consequently, an effective internal control system can only provide reasonable, not absolute, assurance, with respect to reporting financial information.

Management conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of March 31, 2009.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit us to provide only management's report in this annual report.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The following table sets forth certain information regarding our current directors and executive officers. Our executive officers serve one-year terms.

Name	Age	Position	Board Committee(s)[1]
C. Stephen Cochennet	52	President, Chief Executive Officer, and Chairman	None
Dierdre P. Jones	44	Chief Financial Officer	None
Robert G. Wonish	55	Director	GCNC (Chairman) and Audit
Daran G. Dammeyer	48	Director	Audit (Chairman) and GCNC
Darrel G. Palmer	51	Director	GCNC
Dr. James W. Rector	48	Director	None

(1) "GCNC" means the Governance, Compensation and Nominating Committee of the Board of Directors. "Audit" means the Audit Committee of the Board of Directors.

C. Stephen Cochennet, has been our President, Chief Executive Officer and Chairman since August 15, 2006. From July 2002 to present, Mr. Cochennet has been President of CSC Group, LLC. Mr. Cochennet formed the CSC Group, LLC through which he supports a number of clients that include Fortune 500 corporations, international companies, natural gas/electric utilities, outsource service providers, as well as various start up organizations. The services provided include strategic planning, capital formation, corporate development, executive networking and transaction structuring. Mr. Cochennet currently spends less than 10 hours per month on activities associated with CSC Group, LLC. From 1985 to 2002, he held several executive positions with UtiliCorp United Inc. (Aquila) in Kansas City. His responsibilities included finance, administration, operations, human resources, corporate development, natural gas/energy marketing, and managing several new start up operations. Prior to his experience at UtiliCorp United Inc., Mr. Cochennet served 6 years with the Federal Reserve System. Mr. Cochennet graduated from the University of Nebraska with a B.A. in Finance and Economics.

Dierdre P. Jones was promoted to Chief Financial Officer on July 23, 2008. Ms. Jones was our Director of Finance and Accounting from August 2007 through July 2008. From May 2007 through August 2007, Ms. Jones provided independent consulting services for the company, primarily in the testing and implementation of financial accounting and reporting software. From May 2002 through May 2007, Ms. Jones was sole proprietor of *These Faux Walls,* a specialty design company. She holds the professional designations of Certified Public Accountant and Certified Internal Auditor. Prior to joining EnerJex, Ms. Jones held management positions with UtiliCorp United Inc. (Aquila), and served three years in public accounting with Arthur Andersen & Co. Ms. Jones graduated with distinction from the University of Kansas with a B.S. in Accounting and Business Administration.

Robert G. Wonish has served as a member of our board of directors since May 2007. Effective April 7, 2009, Mr. Wonish was appointed President & Chief Operating Officer of Petrodome Energy, LLC, a privately held firm. From December 2004 to June 30, 2007, Mr. Wonish was Vice President of Petroleum Engineers Inc., a subsidiary of The CYMRI Corporation, now CYMRI, L.L.C., which is a wholly-owned subsidiary of Stratum Holdings, Inc. On July 1, 2007, Mr. Wonish was appointed President and Chief Operating Officer of Petroleum Engineers Inc. Mr. Wonish was also President of CYMRI, L.L.C. After the sale of Petroleum Engineers Inc. in March of 2008, Mr. Wonish resigned all positions in Petroleum Engineers Inc. and CYMRI, L.L.C. as well as resigning as a member of the Stratum Holdings, Inc. board of directors. Mr. Wonish held the position of President & Chief Operating Officer of Striker Oil & Gas, Inc. prior to his engagement with Petrodome Energy, LLC.. He previously achieved positions of increasing responsibility with PANACO, Inc., a public oil and natural gas company, ultimately serving as that company's President and Chief Operating Officer. He began his engineering career at Amoco in 1975 and joined Panaco's engineering staff in 1992. Mr. Wonish serves as EnerJex's chairman of the Governance, Compensation and Nominating committee and is a member of the company's audit committee. Mr. Wonish received his Mechanical Engineering degree from the University of Missouri-Rolla.

Daran G. Dammeyer, has served as a member of our board of directors since May 2007. Since July 1999, Mr. Dammeyer has served as President of D-Two Solutions through which he supports clients by primarily providing merger and acquisition support, strategic planning, budgeting and forecasting process development and implementation. From March 1999 through July 1999, Mr. Dammeyer was a Director of International Financial Management for UtiliCorp United Inc. (Aquila), a multinational energy solutions provider in Kansas City, Missouri. From November 1995 through March 1999, Mr. Dammeyer served as the Chief Financial Controller of United Energy Limited in Melbourne, Australia. Mr. Dammeyer also served in numerous management positions at Michigan Energy Resources Company, including Director of Internal Audit. Mr. Dammeyer earned his Bachelor of Business Administration degree, with dual majors in Accounting and Corporate Financial Management from The University of Toledo, Ohio.

Darrel G. Palmer, has served as a member of our board of directors since May of 2007. Since January 1997, Mr. Palmer has been President of Energy Management Resources, an energy process management firm serving industrial and large commercial companies throughout the U. S. and Canada. Mr. Palmer has 25 years of expertise in the natural gas arena. His experiences encompass a wide area of the natural gas industry and include working for natural gas marketing companies, local distribution companies, and FERC regulated pipelines. Prior to becoming an independent energy consultant in 1997, Mr. Palmer's last position was Vice President/National Account Sales at UtiliCorp United Inc. (Aquila) of Kansas City, Missouri. Over the years Mr. Palmer has worked in many civic organizations including United Way and has been a President of the local Kiwanis Club. Junior Achievement of Minnesota awarded him the Bronze Leadership Award for his accomplishments which included being an advisor, program manager, holding various Board positions, and ultimately being Board President.

Dr. James W. Rector, has served as a member of our board of directors since March 19, 2008. Dr. Rector is the author of numerous technical papers along with a number of patents on seismic technology. He was a co-founder of two seismic technology startups that were later sold to NYSE-listed companies, and he regularly consults for many of the major oil companies including Chevron and BP. In 1998, he founded Berkeley GeoImaging LLC, which has completed five equity private placements for oil and natural gas exploration and development projects. Dr. Rector is a tenured professor of Geophysics at the University of California at Berkeley and a faculty staff scientist at the Lawrence Berkeley National Laboratory. He has been the Editor-in-Chief of the *Journal of Applied Geophysics* and has also served on the Society of Exploration Geophysicists Executive Committee. He received his Masters and Ph.D. degrees in Geophysics from Stanford University.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), requires our executive officers and directors, and persons who beneficially own more than ten percent of our common stock, to file initial reports of ownership and reports of changes in ownership with the SEC. Executive officers, directors and greater than ten percent beneficial owners are required by SEC regulations to furnish us with copies of all Section 16(a) forms they file. Based upon a review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that as of the date of this report they were all current in their 16(a) reports.

Board of Directors

Our board of directors currently consists of five members. Our directors serve one-year terms. Our board of directors has affirmatively determined that Messrs. Wonish, Dammeyer, Palmer and Dr. Rector are independent directors, as defined by Section 803 of the American Stock Exchange Company Guide.

Committees of the Board of Directors

Our board of directors has two standing committees: an audit committee and a governance, compensation and nominating committee. Each of those committees has the composition and responsibilities set forth below.

Audit Committee

On May 4, 2007, we established and appointed initial members to the audit committee of our board of directors. Mr. Dammeyer is the chairman and Mr. Wonish serves as the other member of the committee. Currently, none of the members of the audit committee are, or have been, our officers or employees, and each member qualifies as an independent director as defined by Section 803 of the American Stock Exchange Company Guide and Section 10A(m) of the Securities Exchange Act of 1934, and Rule 10A-3 thereunder. The Board of Directors has determined that Mr. Dammeyer is an “audit committee financial expert” as that term is used in Item 401(h) of Regulation S-K promulgated under the Securities Exchange Act. The audit committee held five meetings during fiscal 2009.

The audit committee has the sole authority to appoint and, when deemed appropriate, replace our independent registered public accounting firm, and has established a policy of pre-approving all audit and permissible non-audit services provided by our independent registered public accounting firm. The audit committee has, among other things, the responsibility to evaluate the qualifications and independence of our independent registered public accounting firm; to review and approve the scope and results of the annual audit; to review and discuss with management and the independent registered public accounting firm the content of our financial statements prior to the filing of our quarterly reports and annual reports; to review the content and clarity of our proposed communications with investors regarding our operating results and other financial matters; to review significant changes in our accounting policies; to establish procedures for receiving, retaining, and investigating reports of illegal acts involving us or complaints or concerns regarding questionable accounting or auditing matters, and supervise the investigation of any such reports, complaints or concerns; to establish procedures for the confidential, anonymous submission by our employees of concerns or complaints regarding questionable accounting or auditing matters; and to provide sufficient opportunity for the independent auditors to meet with the committee without management present.

Governance, Compensation and Nominating Committee

The governance, compensation and nominating committee is comprised of Messrs. Wonish, Dammeyer and Palmer. Mr. Wonish serves as the chairman of the governance, compensation and nominating committee. The governance, compensation and nominating committee is responsible for, among other things; identifying, reviewing, and evaluating individuals qualified to become members of the Board, setting the compensation of the Chief Executive Officer and performing other compensation oversight, reviewing and recommending the nomination of Board members, and administering our equity compensation plans. The governance, compensation and nominating committee held five meetings during fiscal 2009.

Code of Ethics

We have adopted a Code of Business Conduct and Ethics that applies to all of our directors, officers and employees, as well as to directors, officers and employees of each subsidiary of the Company. Our Code of Ethics was filed as Exhibit 99.6 to the Annual Report on Form 10-KSB for the year ended March 31, 2007 which was filed on June 13, 2007. A copy of our Code of Business Conduct and Ethics will be provided to any person, without charge, upon request. It is available on our website: enerjexresources.com, or you may contact C. Stephen Cochennet at 913-754-7754 to request a copy of the Code or send your request to EnerJex Resources, Inc., Attn: C. Stephen Cochennet, 27 Corporate Woods, Suite 350, 10975 Grandview Drive, Overland Park, Kansas 66210. If any substantive amendments are made to the Code of Business Conduct and Ethics or if we grant any waiver, including any implicit waiver, from a provision of the Code to any of our officers and directors, we will disclose the nature of such amendment or waiver in a report on Form 8-K.

Limitation of Liability of Directors

Pursuant to the Nevada General Corporation Law, our Articles of Incorporation exclude personal liability for our Directors for monetary damages based upon any violation of their fiduciary duties as Directors, except as to liability for any breach of the duty of loyalty, acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, or any transaction from which a Director receives an improper personal benefit. This exclusion of liability does not limit any right which a Director may have to be indemnified and does not affect any Director’s liability under federal or applicable state securities laws. We have agreed to indemnify our directors against expenses, judgments, and amounts paid in settlement in connection with any claim against a Director if he acted in good faith and in a manner he believed to be in our best interests.

Nevada Anti-Takeover Law and Charter and By-law Provisions

Depending on the number of residents in the state of Nevada who own our shares, we could be subject to the provisions of Sections 78.378 *et seq*. of the Nevada Revised Statutes which, unless otherwise provided in a company’s articles of incorporation or by-laws, restricts the ability of an acquiring person to obtain a controlling interest of 20% or more of our voting shares. Our articles of incorporation and by-laws do not contain any provision which would currently keep the change of control restrictions of Section 78.378 from applying to us.

We are subject to the provisions of Sections 78.411 *et seq*. of the Nevada Revised Statutes. In general, this statute prohibits a publicly held Nevada corporation from engaging in a "combination" with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the combination or the transaction by which the person became an interested stockholder is approved by the corporation's board of directors before the person becomes an interested stockholder. After the expiration of the three-year period, the corporation may engage in a combination with an interested stockholder under certain circumstances, including if the combination is approved by the board of directors and/or stockholders in a prescribed manner, or if specified requirements are met regarding consideration. The term "combination" includes mergers, asset sales and other transactions resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an "interested stockholder" is a person who, together with affiliates and associates, owns, or within three years did own, 10% or more of the corporation's voting stock. A Nevada corporation may "opt out" from the application of Section 78.411 *et seq.* through a provision in its articles of incorporation or by-laws. We have not "opted out" from the application of this section.

Apart from Nevada law, however, our articles of incorporation and by-laws do not contain any provisions which are sometimes associated with inhibiting a change of control from occurring (i.e., we do not provide for a staggered board, or for "super-majority" votes on major corporate issues). However, we do have 10,000,000 shares of authorized "blank check" preferred stock, which could be used to inhibit a change in control.

ITEM 11. EXECUTIVE COMPENSATION.

The following table sets forth summary compensation information for the fiscal years ended March 31, 2009 and 2008 for our chief executive officer and chief financial officer. We did not have any other executive officers as of the end of fiscal 2009 whose total compensation exceeded $100,000. We refer to these persons as our named executive officers elsewhere in this report.

Summary Compensation Table

Name and Principal Position	Fiscal Year	Salary ($)	Bonus ($)	Option Awards ($)	All Other Compen-sation ($)	Total ($)
C. Stephen Cochennet	2009	$ 186,525	$ 50,000	$ -(2)	$ -	$ 236,525
President, Chief Executive Officer	2008	$ 156,000	-	859,622(1)	-	$ 1,015,622
Dierdre P. Jones	2009	$ 128,808	$ 10,000	-(2)	-	$ 138,808
Chief Financial Officer	2008	-(3)	-(3)	-(3)	-(3)	-(3)

(1) Amount represents the estimated total fair value of stock options granted to Mr. Cochennet under SFAS 123(R).

(2) In August, 2008, we granted C. Stephen Cochennet, our chief executive officer, an option to purchase 75,000 shares of our common stock at $6.25 per share and we granted Dierdre P. Jones, our chief financial officer, and option to purchase 40,000 shares of our common stock at $6.25 per share under SFAS 123(R) as discussed in Note 3 to our financial statements for the year ended March 31, 2009 included elsewhere in this report. These options were rescinded in November 2008 at the request of the board's compensation committee and the approval of each option holder.

(3) Ms. Jones was promoted to chief financial officer during fiscal 2009 and was not a named executive officer in fiscal 2008.

Outstanding Equity Awards at 2008 Fiscal Year-End

The following table lists the outstanding equity incentive awards held by our named executive officers as of March 31, 2009.

		Option Awards				
	Fiscal Year	Number of Securities Underlying Unexercised Options Exercisable (#)	Number of Securities Underlying Unexercised Options Unexercisable (#)	Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date
C. Stephen Cochennet	2009	200,000	-	-	$ 6.25	05/03/2011
Dierdre P. Jones	2009	20,000	-	-	$ 6.30	07/31/2011

Option Exercises for fiscal 2009

There were no options exercised by our named executive officers in fiscal 2009. See "Securities Authorized for Issuance under Equity Compensation Plans" on page 49 for a description of our outstanding equity compensation plans.

Potential Payments Upon Termination or Change in Control

We entered into employment agreements with both of our named executive officers which could result in payments to such officers because of their resignation, incapacity or disability, or other termination of employment with us or our subsidiaries, or a change in control, or a change in the person's responsibilities following a change in control.

Director Compensation

The following table sets forth summary compensation information for the fiscal year ended March 31, 2009 for each of our non-employee directors.

Name	Fees Earned or Paid in Cash $	Stock Awards $	Option Awards (2) $	All Other Compensation $	Total $
Daran G. Dammeyer	$ 58,000	$ 12,000(1)	$ -0-	$ -0-	$ 70,000
Darrel G. Palmer	$ 26,500	$ -0-	$ -0-	$ 20,000(3)	$ 46,500
Robert G. Wonish	$ 49,000	$ -0-	$ -0-	$ -0-	$ 49,000
Dr. James W. Rector	$ 22,500	$ -0-	$ -0-	$ -0-	$ 22,500

(1) Amount represents the estimated total fair market value of 2,182 shares of common stock issued to Mr. Dammeyer for services as audit committee chairman under SFAS 123(R), as discussed in Note 3 to our audited financial statements for the year ended March 31, 2009 included elsewhere in this report.

(2) In July, 2008, 28,000 stock options were granted to each of Messrs. Dammeyer, Palmer and Wonish and 38,000 stock options were granted to Dr. Rector under SFAS 123(R), as discussed in Note 3 to our financial statements for the year ended March 31, 2009 included elsewhere in this report. These total 122,000 options granted to Messrs. Dammeyer, Palmer and Wonish and to Dr. Rector were rescinded in November 2008.

(3) Mr. Palmer was paid $20,000 for assisting in the establishment and development of the audit committee and for his involvement and assistance to the chief executive officer in finalizing the hedging instrument with BP.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The following table presents information, to the best of EnerJex's knowledge, about the ownership of EnerJex's common stock on July 14, 2009 relating to those persons known to beneficially own more than 5% of EnerJex's capital stock and by EnerJex's directors and executive officers. The percentage of beneficial ownership for the following table is based on 4,443,512 shares of common stock outstanding.

Beneficial ownership is determined in accordance with the rules of the Securities and Exchange Commission and does not necessarily indicate beneficial ownership for any other purpose. Under these rules, beneficial ownership includes those shares of common stock over which the stockholder has sole or shared voting or investment power. It also includes shares of common stock that the stockholder has a right to acquire within 60 days after July 14, 2009 pursuant to options, warrants, conversion privileges or other right. The percentage ownership of the outstanding common stock, however, is based on the assumption, expressly required by the rules of the Securities and Exchange Commission, that only the person or entity whose ownership is being reported has converted options or warrants into shares of EnerJex's common stock.

Name and Address of Beneficial Owner, Officer or Director(1)	Number of Shares	Percent of Outstanding Shares of Common Stock(2)
C. Stephen Cochennet, President & Chief Executive Officer(3)	600,000(4)	12.5%
Dierdre P. Jones, Chief Financial Officer	20,000	*
Robert (Bob) G. Wonish, Director(3)	40,000(5)	*
Darrel G. Palmer, Director(3)	40,000(5)	*
Daran G. Dammeyer, Director(3)	44,102(5)	*
Dr. James W. Rector, Director(3)	-0-	*
Directors and Officers as a Group		15.6%
West Coast Opportunity Fund LLC(6) West Coast Asset Management, Inc. Paul Orfalea, Lance Helfert & R. Atticus Lowe 2151 Alessandro Drive, #100 Ventura, CA 93001	1,000,000	22.5%
Enable Growth Partners L.P.(7) Enable Capital Management, LLC Mitchell S. Levine One Ferry Building, Suite 225 San Francisco, CA 94111	353,800	8.7%

* Represents beneficial ownership of less than 1%

(1) As used in this table, "beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security, or the sole or shared investment power with respect to a security (i.e., the power to dispose of, or to direct the disposition of, a security).

(2) Figures are rounded to the nearest tenth of a percent.

(3) The address of each person is care of EnerJex Resources: Corporate Woods 27, Suite 350, 10975 Grandview Drive, Overland Park, Kansas 66210.

(4) Includes 200,000 options, exercisable at $6.25 per share through May 3, 2011.

(5) Includes 40,000 options, exercisable at $6.25 per share through May 3, 2011.

(6) Based on a Schedule 13D filed with the SEC on February 13, 2009, the investment manager of West Coast Opportunity Fund, LLC ("WCOF") is West Coast Asset Management ("WCAM"). WCAM has the authority to take any and all actions on behalf of WCOF, including voting any shares held by WCOF. Paul Orfalea, Lance Helfert and R. Atticus Lowe constitute the Investment Committee of WCOF. Messrs. Orfalea, Helfert and Lowe disclaim beneficial ownership of the shares.

(7) Based on a Schedule 13G/A filed with the SEC on February 11, 2009, Enable Capital Management, LLC, as general and investment manager of Enable Growth Partners L.P. and other clients, may be deemed to have the power to direct the voting or disposition of shares of common stock held by Enable Growth Partners L.P. (353,800 shares of common stock) and other clients (285,040 shares of common stock). Therefore, Energy Capital Management, LLC, as Enable Growth Partners L.P.'s and those other accounts' general partner and investment manager, and Mitchell S. Levine, as managing member and majority owner of Enable Capital Management, LLC, may be deemed to beneficially own the shares of common stock owned by Enable Growth Partners L.P. and such other accounts.

Equity Compensation Plan Information

The following table sets forth information as of March 31, 2009 regarding outstanding options granted under our stock option plans and options reserved for future grant under the plans.

Plan Category	Number of shares to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of shares remaining available for future issuance under equity compensation plans (excluding shares reflected in column (a) (c)
Equity compensation plans approved by stockholders	438,500	$ 6.30	761,500
Equity compensation plans not approved by stockholders	—	—	—
Total	438,500	$ 6.30	761,500

On May 4, 2007, we granted a non-qualified option to C. Stephen Cochennet for all 200,000 options available under our 2000 Stock Option and Incentive Plan.

As of March 31, 2009, we have granted 254,330 non-qualified options under our 2002-2003 Stock Option Plan at prices ranging from $6.25 to $6.30 per share.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

We describe below transactions and series of similar transactions that have occurred during this fiscal year to which we were a party or will be a party in which:

- The amounts involved exceeds the lesser of $120,000 or one percent of the average of our total assets at year end for the last two completed fiscal years ($93,280); and

- A director, executive officer, holder of more than 5% of our common stock or any member of their immediate family had or will have a direct or indirect material interest.

Our board of directors has affirmatively determined that Messrs. Wonish, Dammeyer, Palmer and Dr. Rector are independent directors, as defined by Section 803 of the American Stock Exchange Company Guide. Mr. Palmer is not eligible to serve on our Audit Committee pursuant to Section 10A(m)(3) of the Securities Exchange Act of 1934, as amended.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Weaver & Martin, LLC served as our principal independent public accountants for fiscal 2009 and 2008 years. Aggregate fees billed to us for the fiscal years ended March 31, 2009 and 2008 by Weaver & Martin, LLC were as follows:

	For the Fiscal Years Ended March 31, 2009	For the Fiscal Years Ended March 31, 2008
Audit Fees(1)	$ 56,000	$ 105,000
Audit-Related Fees(2)	-0-	-0-
Tax Fees(3)	10,000	13,000
All Other Fees(4)	19,718	-0-
Total fees paid or accrued to our principal accountant	$ 85,718	$ 118,000

(1) Audit Fees include fees billed and expected to be billed for services performed to comply with Generally Accepted Auditing Standards (GAAS), including the recurring audit of the Company's consolidated financial statements for such period included in this Annual Report on Form 10-K and for the reviews of the consolidated quarterly financial statements included in the Quarterly Reports on Form 10-QSB filed with the Securities and Exchange Commission. This category also includes fees for audits provided in connection with statutory filings or procedures related to audit of income tax provisions and related reserves, consents and assistance with and review of documents filed with the SEC.

(2) Audit-Related Fees include fees for services associated with assurance and reasonably related to the performance of the audit or review of the Company's financial statements. This category includes fees related to assistance in financial due diligence related to mergers and acquisitions, consultations regarding Generally Accepted Accounting Principles, reviews and evaluations of the impact of new regulatory pronouncements, general assistance with implementation of Sarbanes-Oxley Act of 2002 requirements and audit services not required by statute or regulation.

(3) Tax fees consist of fees related to the preparation and review of the Company's federal and state income tax returns.

(4) Other fees include fees related to the preparation and review of the Form S-1 Registration Statement.

<u>Audit Committee Policies and Procedures</u>

Our Audit Committee pre-approves all services to be provided to us by our independent auditor. This process involves obtaining (i) a written description of the proposed services, (ii) the confirmation of our Principal Accounting Officer that the services are compatible with maintaining specific principles relating to independence, and (iii) confirmation from our securities counsel that the services are not among those that our independent auditors have been prohibited from performing under SEC rules, as outlined in the Audit Committee charter. The members of the Audit Committee then make a determination to approve or disapprove the engagement of Weaver & Martin for the proposed services. In fiscal 2009, all fees paid to Weaver & Martin were unanimously pre-approved in accordance with this policy.

Less than 50 percent of hours expended on the principal accountant's engagement to audit the registrant's financial statements for the most recent fiscal year were attributed to work performed by persons other than the principal accountant's full-time, permanent employees.

AUDIT COMMITTEE AND INDEPENDENT PUBLIC ACCOUNTANTS

Qualification Of Audit Committee Members

Our Audit Committee consists of two independent directors, each of whom has been selected for membership on the Audit Committee by the Board of Directors based on the Board's determination that he is fully qualified to oversee EnerJex's internal audit function, assess and select independent auditors, and oversee EnerJex's financial reporting processes and overall risk management. The Audit Committee has the authority to seek advice and assistance from outside legal, accounting or other advisors and exercises such authority as it deems necessary. The full text of the charter of the Audit Committee can be found in the investor section of our website at *www.enerjexresources.com*.

Through a range of education, experiences in business and executive leadership and service on the boards of directors, and through experience on EnerJex's Board of Directors and Audit Committee, each member of the Committee has an understanding of generally accepted accounting principles and has experience in evaluating the financial performance of public companies. Moreover, the Audit Committee members have gained valuable special knowledge of the financial condition and performance of EnerJex. The Board has determined that Daran G. Dammeyer is a "financial expert" as that term is used in Item 401(h) of Regulation S-K promulgated under the Securities Exchange Act.

Report Of The Audit Committee Of The Board

The Company's management is responsible for preparing our financial statements and ensuring they are complete and accurate and prepared in accordance with generally accepted accounting principles. Weaver & Martin, LLC, our independent registered public accounting firm, is responsible for performing an independent audit of our consolidated financial statements and expressing an opinion on the conformity of those financial statements with generally accepted accounting principles.

The Audit Committee has reviewed and discussed with our management the audited financial statements of the Company included in our Annual Report on Form 10-K for the fiscal year ended March 31, 2009 ("10-K").

The Audit Committee has also reviewed and discussed with Weaver & Martin, LLC the audited financial statements in the 10-K. In addition, the Audit Committee discussed with Weaver & Martin, LLC those matters required to be discussed by the Statement on Auditing Standards No. 61, as amended. Additionally, Weaver & Martin, LLC provided to the Audit Committee the written disclosures and the letter required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communications with the Audit Committee concerning independence. The Audit Committee also discussed with Weaver & Martin, LLC its independence from the Company.

Based upon the review and discussions described above, the Audit Committee recommended to the Board of Directors that the audited financial statements be included in the Company's 10-K for filing with the United States Securities and Exchange Commission.

Submitted by the following members of the Audit Committee:

Daran G. Dammeyer (Chairman)

Robert G. Wonish

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

The following information required under this item is filed as part of this report:

(a) 1. Financial Statements

2. Financial Statement Schedules

None.

3. Exhibit Index

Exhibit No.	Description
2.1	Agreement and Plan of Merger between Millennium Plastics Corporation and Midwest Energy, Inc. effective August 15, 2006 (incorporated by reference to Exhibit 2.3 to the Form 8-K filed on August 16, 2006)
3.1	Amended and Restated Articles of Incorporation, as currently in effect (incorporated by reference to Exhibit 3.1 to the Form 10-Q filed on August 14, 2008)
3.2	Amended and Restated Bylaws, as currently in effect (incorporated by reference to Exhibit 3.3 to the Form SB-2 filed on February 23, 2001)
4.1	Article VI of Amended and Restated Articles of Incorporation of Millennium Plastics Corporation (incorporated by reference to Exhibit 1.3 to the Form 8-K filed on December 6, 1999)
4.2	Article II and Article VIII, Sections 3 & 6 of Amended and Restated Bylaws of Millennium Plastics Corporation (incorporated by reference to Exhibit 4.1 to the Form SB-2 filed on February 23, 2001)
4.3	Specimen common stock certificate (incorporated by reference to Exhibit 4.3 to the Form S-1/A filed on May 27, 2008)
10.1	Credit Agreement with Texas Capital Bank, N.A. dated July 3, 2008 (incorporated by reference to Exhibit 10.33 to the Form 10-K filed on July 10, 2008)
10.2	Promissory Note to Texas Capital Bank, N.A. dated July 3, 2008 (incorporated by reference to Exhibit 10.34 to the Form 10-K filed on July 10, 2008)
10.3	Amended and Restated Mortgage, Security Agreement, Financing Statement and Assignment of Production and Revenues with Texas Capital Bank, N.A. dated July 3, 2008 (incorporated by reference to Exhibit 10.35 to the Form 10-K filed on July 10, 2008)
10.4	Security Agreement with Texas Capital Bank, N.A. dated July 3, 2008 (incorporated by reference to Exhibit 10.36 to the Form 10-K filed on July 10, 2008)
10.5	Letter Agreement with Debenture Holders dated July 3, 2008 (incorporated by reference to Exhibit 10.37 to the Form 10-K filed on July 10, 2008)
10.6†	C. Stephen Cochennet Employment Agreement dated August 1, 2008 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on August 1, 2008)
10.7†	Dierdre P. Jones Employment Agreement dated August 1, 2008 (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on August 1, 2008)
10.8†	Amended and Restated EnerJex Resources, Inc. Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on October 16, 2008)
10.9	Form of Officer and Director Indemnification Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K filed on October 16, 2008)
10.10	Euramerica Letter Agreement Amendment dated September 15, 2008 (incorporated by reference to Exhibit 10.10 to the Form 8-K filed on September 18, 2008)
10.11	Euramerica Letter Agreement Amendment dated October 15, 2008 (incorporated by reference to Exhibit 10.11 to the Form 8-K filed on October 21, 2008)
10.12(a) †	C. Stephen Cochennet Rescission of Option Grant Agreement dated November 17, 2008 (incorporated by reference to Exhibit 10.38(a) to the Form 10-Q filed on February 23, 2009)

10.12(b) †	Dierdre P. Jones Rescission of Option Grant Agreement dated November 17, 2008 (incorporated by reference to Exhibit 10.38(b) to the Form 10-Q filed on February 23, 2009)
10.12(c)	Daran G. Dammeyer Rescission of Option Grant Agreement dated November 17, 2008 (incorporated by reference to Exhibit 10.38(c) to the Form 10-Q filed on February 23, 2009)
10.12(d)	Darrel G. Palmer Rescission of Option Grant Agreement dated November 17, 2008 (incorporated by reference to Exhibit 10.38(d) to the Form 10-Q filed on February 23, 2009)
10.12(e)	Dr. James W. Rector Rescission of Option Grant Agreement dated November 17, 2008 (incorporated by reference to Exhibit 10.38(e) to the Form 10-Q filed on February 23, 2009)
10.12(f)	Robert G. Wonish Rescission of Option Grant Agreement dated November 17, 2008 (incorporated by reference to Exhibit 10.38(f) to the Form 10-Q filed on February 23, 2009)
10.13	Letter Agreement with Debenture Holders dated June 11, 2009 (incorporated by reference to Exhibit 10.1 to the Form 8-K filed on June 16, 2009)
10.14	Joint Operating Agreement with Pharyn Resources to explore and develop the Brownrigg Lease Press Release dated June 1, 2009 (incorporated by reference to Exhibit 99.1 to the Form 8-K filed on June 5, 2009)
10.15	Amendment 4 to Joint Exploration Agreement effective as of November 6, 2008 between MorMeg, LLC and EnerJex Resources, Inc.
10.16	Waiver from Texas Capital Bank, N.A. dated July 14, 2009
21.1	List of Subsidiaries
23.1	Miller & Lents, Ltd. Consent Of Independent Petroleum Engineers and Geologists Letter dated June 24, 2009 and effective March 31, 2009
23.2	Consent of Weaver & Martin, LLC
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

† Indicates management contract or compensatory plan or arrangement.

SIGNATURES

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

ENERJEX RESOURCES, INC.

By: /s/ C. Stephen Cochennet
C. Stephen Cochennet, Chief Executive Officer

Date: July 14, 2009

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

ENERJEX RESOURCES, INC.

By: /s/ Dierdre P Jones
Dierdre P Jones, Chief Financial Officer

Date: July 14, 2009

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

Name	Title	Date
/s/ C. Stephen Cochennet C. Stephen Cochennet	President, Chief Executive Officer, (Principal Executive Officer), Secretary, Chairman	July 14, 2009
/s/ Dierdre P Jones Dierdre P. Jones	Chief Financial Officer	July 14, 2009
/s/ Robert G. Wonish Robert G. Wonish	Director	July 14, 2009
/s/ Daran G. Dammeyer Daran G. Dammeyer	Director	July 14, 2009
/s/ Darrel G. Palmer Darrel G. Palmer	Director	July 14, 2009
/s/ Dr. James W. Rector Dr. James W. Rector	Director	July 14, 2009

Index to Financial Statements

Report of Independent Registered Public Accounting Firm

Stockholders and Directors
EnerJex Resources, Inc.
Overland Park, Kansas

We have audited the accompanying consolidated balance sheet of EnerJex Resources, Inc. as of March 31, 2009 and 2008 and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the two-year period ended March 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EnerJex Resources, Inc. as of March 31, 2009 and 2008 and the consolidated results of its operations and cash flows for each of the years in the two–year period ended March 31, 2009 in conformity with accounting principles generally accepted in the United States of America.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has suffered recurring losses and had negative cash flows that raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters are described in the Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/S/

Weaver & Martin, LLC
Kansas City, Missouri
July 9, 2009

EnerJex Resources, Inc. and Subsidiaries
Consolidated Balance Sheets

	March 31, 2009	March 31, 2008
Assets		
Current assets:		
Cash	$ 127,585	$ 951,004
Accounts receivable	462,044	227,055
Prepaid debt issue costs	45,929	157,191
Deposits and prepaid expenses	263,383	176,345
Total current assets	898,941	1,511,595
Fixed assets	365,019	185,299
Less: Accumulated depreciation	63,988	30,982
Total fixed assets	301,031	154,317
Other assets:		
Prepaid debt issue costs	-	157,191
Oil and gas properties using full-cost accounting:		
Properties not subject to amortization	31,183	62,216
Properties subject to amortization	6,449,023	8,982,510
Total other assets	6,480,206	9,201,917
Total assets	$ 7,680,178	$ 10,867,829
Liabilities and Stockholders' Equity (Deficit)		
Current liabilities:		
Accounts payable	$ 1,016,168	$ 416,834
Accrued liabilities	87,811	70,461
Notes payable	-	965,000
Deferred payments from Euramerica development	-	251,951
Long-term debt, current	1,723,036	412,930
Total current liabilities	2,827,015	2,117,176
Asset retirement obligation	803,624	459,689
Convertible note payable	25,000	25,000
Long-term debt, net of discount of $596,108	7,818,163	6,831,972
Total liabilities	11,473,802	9,433,837
Contingencies and commitments		
Stockholders' Equity (Deficit):		
Preferred stock, $0.001 par value, 10,000,000 shares authorized, no shares issued and outstanding	-	-
Common stock, $0.001 par value, 100,000,000 shares authorized; shares issued and outstanding –4,443,512 at March 31, 2009 and 4,440,651 at March 31, 2008	4,444	4,441
Paid in capital	8,932,906	8,853,457
Retained (deficit)	(12,730,974)	(7,423,906)
Total stockholders' equity (deficit)	(3,793,624)	1,433,992
Total liabilities and stockholders' equity (deficit)	$ 7,680,178	$ 10,867,829

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc. and Subsidiaries
Consolidated Statements of Operations

	For the Fiscal Years Ended March 31, 2009	2008
Oil and natural gas revenues	$ 6,436,805	$ 3,602,798
Expenses:		
Direct operating costs	2,637,333	1,795,188
Depreciation, depletion and amortization	911,293	935,330
Impairment of oil and gas properties	4,777,723	-
Professional fees	1,320,332	1,226,998
Salaries	849,340	1,703,099
Administrative expense	1,392,645	887,872
Total expenses	11,888,666	6,548,487
Loss from operations	(5,451,861)	(2,945,689)
Other income (expense):		
Interest expense	(882,426)	(792,448)
Loan interest accretion	(2,814,095)	(1,089,798)
Gain on liquidation of hedging instrument	3,879,050	-
Other Gain/(Loss)	(37,736)	-
Total other income (expense)	144,793	(1,882,246)
Net income - (loss)	$ (5,307,068)	$ (4,827,935)
Weighted average shares outstanding - basic	4,443,249	4,284,144
Net income (loss) per share - basic	$ (1.19)	$ (1.13)

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity (Deficit)

	Common Stock					
	Shares	Par Value	Owed but not issued	Paid in Capital	Retained Deficit	Total Stockholders' Equity (Deficit)
Balance, April 1, 2007	2,635,731	$ 2,636	$ 3	$ 2,548,742	$ (2,595,971)	$ (44,590)
Stock sold	1,800,000	1,800	-	4,311,956	-	4,313,756
Stock issued for services	1,920	2	-	14,998	-	15,000
Previously authorized but unissued stock	3,000	3	(3)	-	-	-
Stock options issued for services	-	-	-	1,977,761	-	1,977,761
Net (loss) for the year	-	-	-	-	(4,827,935)	(4,827,935)
Balance, March 31, 2008	4,440,651	4,441	-	8,853,457	(7,423,906)	1,433,992
Stock options issued for services	-	-	-	67,452	-	67,452
Stock issued for services	2,182	2	-	11,998	-	12,000
Stock issued in reverse stock split	679	1	-	(1)	-	-
Net loss for the year	-	-	-	-	$ (5,307,068)	(5,307,068)
Balance, March 31, 2009	4,443,512	$ 4,444	$ -	$ 8,932,906	$ (12,730,974)	$ (3,793,624)

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc.
Consolidated Statements of Cash Flows

	For the Fiscal Years Ended March 31,	
	2009	**2008**
Cash flows from operating activities		
Net (loss)	$ (5,307,068)	$ (4,827,935)
Depreciation and depletion	950,357	935,330
Debt issue cost amortization	157,191	152,453
Stock and options issued for services	79,452	1,992,761
Accretion of interest on long-term debt discount	2,814,095	1,089,798
Accretion of asset retirement obligation	60,864	30,331
Impairment of oil & gas properties	4,777,723	-
Adjustments to reconcile net (loss) to cash used in operating activities:		
Accounts receivable	(234,989)	(222,917)
Notes and interest receivable	-	10,300
Deposits and prepaid expenses	24,224	(169,672)
Accounts payable	599,334	374,535
Accrued liabilities	17,350	(25,429)
Deferred payment from Euramerica for development	(251,951)	251,951
Cash used in operating activities	3,686,582	(408,494)
Cash flows from investing activities		
Purchase of fixed assets	(204,200)	(149,799)
Additions to oil & gas properties	(3,123,003)	(9,530,321)
Sale of oil & gas properties	300,000	300,000
Note and interest receivable from officer	-	23,100
Proceeds from sale of vehicle		-
Cash used in investing activities	(3,027,203)	(9,357,020)
Cash flows from financing activities		
Proceeds from (repayment of) note payable, net	(965,000)	615,000
Proceeds from sales of common stock	-	4,313,756
Debt issue costs		(466,835)
Borrowings on long-term debt	11,274,843	6,344,816
Payments on long-term debt	(11,792,641)	(189,712)
Cash provided from financing activities	(1,482,798)	10,617,025
Increase (decrease) in cash and cash equivalents	(823,419)	851,511
Cash and cash equivalents, beginning	951,004	99,493
Cash and cash equivalents, end	$ 127,585	$ 951,004
Supplemental disclosures:		
Interest paid	$ 768,053	$ 733,972
Income taxes paid	$ -	$ -
Non-cash transactions:		
Share-based payments issued for services	$ -	$ 280,591

See Notes to Consolidated Financial Statements.

EnerJex Resources, Inc.
Notes to Consolidated Financial Statements

Note 1 – Summary of Accounting Policies

Nature of Business

We are an independent energy company engaged in the business of producing and selling crude oil and natural gas. This crude oil and natural gas is obtained primarily by the acquisition and subsequent exploration and development of mineral leases. Development and exploration may include drilling new exploratory or development wells on these leases. These operations are conducted primarily in Eastern Kansas.

Principles of Consolidation

Our consolidated financial statements include the accounts of our wholly-owned subsidiaries, EnerJex Kansas, Inc., DD Energy, Inc.

Use of Estimates

The preparation of these financial statements requires the use of estimates by management in determining our assets, liabilities, revenues, expenses and related disclosures. Actual amounts could differ from those estimates.

Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear any interest. We regularly review receivables to insure that the amounts will be collected and establish or adjust an allowance for uncollectible amounts as necessary using the specific identification method. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. There were no reserves for uncollectible amounts in the periods presented.

Share-Based Payments

The value we assign to the options and warrants that we issue is based on the fair market value as calculated by the Black-Scholes pricing model. To perform a calculation of the value of our options and warrants, we determine an estimate of the volatility of our stock. We need to estimate volatility because there has not been enough trading of our stock to determine an appropriate measure of volatility. We believe our estimate of volatility is reasonable, and we review the assumptions used to determine this whenever we issue a new equity instruments. If we have a material error in our estimate of the volatility of our stock, our expenses could be understated or overstated.

Income Taxes

We account for income taxes under the Statement of Financial Accounting Standards “SFAS” Statement 109, “Accounting for Income Taxes”. The asset and liability approach requires the recognition of deferred tax liabilities and assets for the expected future tax consequences of temporary differences between the carrying amounts and the tax basis of assets and liabilities. The provision for income taxes differs from the amount currently payable because of temporary differences in the recognition of certain income and expense items for financial reporting and tax reporting purposes.

We adopted the Financial Accounting Standards Board “FASB” Interpretation No. 48, “Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109” (“FIN 48”) as of April 1, 2007. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in companies’ financial statements in accordance with FASB Statement No. 109, “Accounting for Income Taxes”. As a result, we apply a more-likely-than-not recognition threshold for all tax uncertainties. FIN 48 only allows the recognition of those tax benefits that have a greater than fifty percent likelihood of being sustained upon examination by the taxing authorities. As a result of implementing FIN 48, we have reviewed our tax positions and determined there were no outstanding or retroactive tax positions with less than a 50% likelihood of being sustained upon examination by the taxing authorities, therefore the implementation of this standard has not had a material effect on the Company.

We classify tax-related penalties and net interest on income taxes as income tax expense. As of March 31, 2009 and 2008, no income tax expense had been incurred.

Fair Value of Financial Instruments

Our financial instruments consist of accounts receivable and notes payable. Interest rates currently available to us for debt with similar terms and remaining maturities are used to estimate fair value of such financial instruments. Accordingly the carrying amounts are a reasonable estimate of fair value.

Earnings Per Share

SFAS No. 128, “Earnings Per Share”, requires dual presentation of basic and diluted earnings per share on the face of the income statement for all entities with complex capital structures and requires a reconciliation of the numerator and denominator of the diluted income or loss per share computation.

For the year ended March 31, 2009 and 2008, there were 513,500 and 533,500, respectively, of potentially issuable shares of common stock pursuant to outstanding stock options and warrants. These have been excluded from the denominator of the diluted earnings per share computation, as their effect would be anti-dilutive.

Cash and Cash Equivalents

We consider all highly liquid investment instruments purchased with original maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows and other statements. We maintain cash on deposit, which, at times, exceed federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Revenue Recognition and Imbalances

Oil and gas revenues are recognized net of royalties when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collection of the revenue is probable. Cash received relating to future revenues is deferred and recognized when all revenue recognition criteria are met.

We use the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which we are entitled based on our interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves net to us will not be sufficient to enable the under-produced owner to recoup its entitled share through production. No receivables are recorded for those wells where we have taken less than our share of production. Gas imbalances are reflected as adjustments to estimates of proved gas reserves and future cash flows in the supplemental oil and gas disclosures. There was no imbalance at March 31, 2009 and 2008.

Goodwill

Goodwill represents the excess of the purchase price of an entity over the estimated fair value of the assets acquired and liabilities assumed. We assess the carrying amount of goodwill by testing the goodwill for impairment annually and when impairment indicators arise. The impairment test requires allocating goodwill and all other assets and liabilities to assigned reporting units. The fair value of each unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense.

Property and Equipment

Property and equipment are recorded at cost. Depreciation is on a straight-line method using the estimated lives of the assets. (3-15 years). Expenditures for maintenance and repairs are charged to expense.

Debt issue costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt on the straight-line method of amortization over the estimated life of the debt.

Oil and Gas Properties

The accounting for our business is subject to special accounting rules that are unique to the gas and oil industry. There are two allowable methods of accounting for oil and gas business activities: the successful efforts method and the full-cost method. We follow the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities.

Under the full-cost method, capitalized costs are amortized on a composite unit-of-production method based on proved gas and oil reserves. Depreciation, depletion and amortization expense is also based on the amount of estimated reserves. If we maintain the same level of production year over year, the depreciation, depletion and amortization expense may be significantly different if our estimate of remaining reserves changes significantly. Proceeds from the sale of properties are accounted for as reductions of capitalized costs unless such sales involve a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved properties, in which case a gain or loss is recognized. The costs of unproved properties are excluded from amortization until the properties are evaluated. We review all of our unevaluated properties quarterly to determine whether or not and to what extent proved reserves have been assigned to the properties, and otherwise if impairment has occurred. Unevaluated properties are assessed individually when individual costs are significant.

The process of estimating gas and oil reserves is very complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates.

We review the carrying value of our gas and oil properties under the full-cost accounting rules of the SEC on a quarterly basis. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current SEC regulations require us to utilize prices at the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to estimates of gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, gas and oil prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

As previously announced, in December 2008, the Securities and Exchange Commission ("SEC") issued new regulations for oil and gas reserve reporting which go into effect effective for fiscal years ending on or after December 31, 2009. One of the key elements of the new regulations relate to the commodity prices which are used to calculate reserves and their present value. The new regulations provide for disclosure of oil and gas reserves evaluated using annual average prices based on the prices in effect on the first day of each month rather than the current regulations which utilize commodity prices on the last day of the year.

All reserve estimates are prepared based upon a review of production histories and other geologic, economic, ownership and engineering data.

Long-Lived Assets

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the assets is then reduced to their estimated fair value that is usually measured based on an estimate of future discounted cash flows.

Asset Retirement Obligations

The asset retirement obligation relates to the plug and abandonment costs when our wells are no longer useful. We determine the value of the liability by obtaining quotes for this service and estimate the increase we will face in the future. We then discount the future value based on an intrinsic interest rate that is appropriate for us. If costs rise more than what we have expected there could be additional charges in the future, however, we monitor the costs of the abandoned wells and we will adjust this liability if necessary.

Major Purchasers

For the years ended March 31, 2009 and 2008 we sold all of our natural gas production to one purchaser. We sold all of our oil production to one purchaser during fiscal 2009 and to a single, but different purchaser in fiscal 2008.

Recent Issued Accounting Standards

In May 2008, the Financial Accounting Standards Board ("FASB") issued SFAS No. 163, "*Accounting for Financial Guarantee Insurance Contracts – An interpretation of FASB Statement No. 60*". SFAS No. 163 requires that an insurance enterprise recognize a claim liability prior to an event of default when there is evidence that credit deterioration has occurred in an insured financial obligation. It also clarifies how Statement 60 applies to financial guarantee insurance contracts, including the recognition and measurement to be used to account for premium revenue and claim liabilities, and requires expanded disclosures about financial guarantee insurance contracts. It is effective for financial statements issued for fiscal years beginning after December 15, 2008, except for some disclosures about the insurance enterprise's risk-management activities. SFAS No. 163 requires that disclosures about the risk-management activities of the insurance enterprise be effective for the first period beginning after issuance. Except for those disclosures, earlier application is not permitted. The adoption of this statement is not expected to have a material effect on the Company's financial statements.

In May 2008, the FASB issued SFAS No. 162, "*The Hierarchy of Generally Accepted Accounting Principles*". SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles in the United States. It is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "*The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles*". The adoption of this statement is not expected to have a material effect on the Company's financial statements.

In March 2008, the Financial Accounting Standards Board ("FASB") issued SFAS No. 161, "*Disclosures about Derivative Instruments and Hedging Activities – an amendment to FASB Statement No. 133*". SFAS No. 161 is intended to improve financial standards for 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. Entities are required to provide enhanced disclosures about: (a) how and why an entity uses derivative instruments; (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations; and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. It is effective for financial statements issued for fiscal years beginning after November 15, 2008, with early adoption encouraged. The Company is currently evaluating the impact of SFAS No. 161 on its financial statements, and the adoption of this statement is not expected to have a material effect on the Company's financial statements.

In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 141 (revised 2007), "Business Combinations". This statement replaces SFAS No. 141 and defines the acquirer in a business combination as the entity that obtains control of one or more businesses in a business combination and establishes the acquisition date as the date that the acquirer achieves control. SFAS 141 (revised 2007) requires an acquirer to recognize the assets acquired, the liabilities assumed, and any non-controlling interest in the acquired at the acquisition date, measured at their fair values as of that date. SFAS 141 (revised 2007) also requires the acquirer to recognize contingent consideration at the acquisition date, measured at its fair value at that date. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. The adoption of this statement is not expected to have a material effect on the Company's financial statements.

In December 2007, the FASB issued SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements Liabilities –an Amendment of ARB No. 51". This statement amends ARB 51 to establish accounting and reporting standards for the Non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited. The adoption of this statement is not expected to have a material effect on the Company's financial statements.

Reclassifications

Certain reclassifications have been made to prior periods to conform to current presentation.

Note 2 – Going Concern

The accompanying consolidated financial statements have been prepared assuming that we will continue as a going concern. Our ability to continue as a going concern is dependent upon attaining profitable operations based on the development of products that can be sold. We intend to use borrowings, equity and asset sales, and other strategic initiatives to mitigate the affects of our cash position, however, no assurance can be given that debt or equity financing, if and when required, will be available. The financial statements do not include any adjustments relating to the recoverability and classification of recorded assets and classification of liabilities that might be necessary should we be unable to continue in existence.

Note 3 – Stock Transactions

Stock transactions in fiscal 2009:

We issued 2,182 shares of common stock to a Director and chairman of our Audit Committee for services over the next year. For the year ended March 31, 2009, we recorded director compensation in the amount $13,000.

Option and Warrant transactions:

Officers (including officers who are members of the board of directors), directors, employees and consultants are eligible to receive options under our stock option plans. We administer the stock option plans and we determine those persons to whom options will be granted, the number of options to be granted, the provisions applicable to each grant and the time periods during which the options may be exercised. No options may be granted more than ten years after the date of the adoption of the stock option plans.

Each option granted under the stock option plans will be exercisable for a term of not more than ten years after the date of grant. Certain other restrictions will apply in connection with the plans when some awards may be exercised. In the event of a change of control (as defined in the stock option plans), the vesting date on which all options outstanding under the stock option plans may first be exercised will be accelerated. Generally, all options terminate 90 days after a change of control.

2000-2001 Stock Option Plan

The Board of Directors approved a stock option plan and our stockholders ratified the plan on September 25, 2000. The total number of options that can be granted under the plan is 200,000 shares. At March 31, 2009, we had granted 200,000 non-qualified options under this plan.

Stock Option Plan

On May 4, 2007, we amended and restated the EnerJex Resources, Inc. Stock Option Plan to rename the plan and to increase the number of shares issuable under the plan to 1,000,000. Our stockholders approved this plan in September of 2007. At March 31, 2009 we had granted 238,500 non-qualified options under this plan.

Option transactions in fiscal 2008:

The unvested option issued in the year ended March 31, 2007, was unexercised and cancelled in accordance with a separation agreement. We recognized the remaining expense ($61,187) relating to the options in the year ended March 31, 2008.

We granted 458,500 options in the year ended March 31, 2008. 30,000 of the options were for services earned over a one-year period. We measured the compensation cost of the options based on the vesting and the market value as determined by the Black-Scholes pricing model.

For the year ended March 31, 2008, we included as expense $1,977,761 relating to the value of vested options.

The fair value of each option award was estimated on the date of grant using the assumptions noted in the following table. Volatility is based on the historical volatility of stock trading, expected term was the estimated exercise period, risk free rate was the rate of a U.S. Treasury instrument of the time period in which the options would be outstanding, and dividend rate was estimated to be zero as we cannot assume that there will be any future dividends.

Weighted average expected volatility	101%
Weighted average expected term (in years)	3.95
Weighted average expected dividends	0%
Weighted average risk free rate	4.42%

The weighted average grant date fair value of the options granted in the year ended March 31, 2009 was $4.35.

In the year ended March 31, 2008, we granted warrants to purchase 75,000 shares of our common stock as partial payment for services rendered in connection with our financing activities. The warrants have an exercise price of $3.00 and expire on April 11, 2010. The fair value of the warrants based on the Black-Scholes pricing model totaled $280,591 (approximately $3.75 per warrant). The following assumptions were used in the valuation: stock price-$1.00; exercise price-$0.60; life- 3 years; volatility- 106%; yield-4.66%. We have included the value of the warrants with the loan and equity transaction costs (See Note 5).

Option transactions in fiscal 2009:

We cancelled 20,000 options in accordance with the provisions regarding terminations in the Stock Option Plan.

At March 31, 2009, we included as expense $66,456 relating to the options that were for services earned over a one-year period.

A summary of stock options and warrants is as follows:

	Options	Weighted Ave. Exercise Price	Warrants	Weighted Ave. Exercise Price
Outstanding April 1, 2007	60,000	$ 6.25	-	
Granted	458,500	6.30	75,000	$ 3.00
Cancelled	(60,000)	(6.25)	-	-
Exercised	-	-	-	-
Outstanding March 31, 2008	458,500	$ 6.30	75,000	$ 3.00
Granted	-	-	-	-
Cancelled	(20,000)	(6.25)	-	-
Exercised	-	-	-	-
Outstanding March 31, 2009	438,500	$ 6.30	75,000	$ 3.00

Note 4 – Asset Retirement Obligation

Our asset retirement obligations relate to the abandonment of oil and natural gas wells. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, inflation rates and credit adjusted risk-free interest rates. The following shows the changes in asset retirement obligations:

Asset retirement obligation at April 1, 2007	$ 23,908
Liabilities incurred during the period	405,450
Liabilities settled during the period	-
Accretion	30,331
Asset retirement obligations, March 31, 2008	459,689
Liabilities incurred during the period	283,071
Liabilities settled during the period	-
Accretion	60,864
Asset retirement obligations, March 31, 2009	$ 803,624

Note 5 - Long-Term Debt

Senior Secured Credit Facility

On July 3, 2008, EnerJex, EnerJex Kansas, and DD Energy entered into a three-year $50 million Senior Secured Credit Facility (the "Credit Facility") with Texas Capital Bank, N.A. Borrowings under the Credit Facility will be subject to a borrowing base limitation based on our current proved oil and gas reserves and will be subject to semi-annual redeterminations and interim adjustments. The initial borrowing base was set at $10.75 million and was reduced to $7.428 million following the liquidation of the BP hedging instrument. The Credit Facility is secured by a lien on substantially all assets of the Company and its subsidiaries. The Credit Facility has a term of three years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on July 3, 2011. The Credit Facility also provides for the issuance of letters-of-credit up to a $750,000 sub-limit under the borrowing base and up to an additional $2.25 million limit not subject to the borrowing base to support our hedging program. We had borrowings $7.328 million outstanding at March 31, 2009.

Advances under the Credit Facility will be in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of (1) the lender's "prime rate" and (2) the Federal Funds rate plus 0.50%, plus, in either case, a margin of between 0.0% and 0.5% depending on the percent of the borrowing base utilized at the time of the credit extension. The interest rate on the Eurodollar loans fluctuates based upon the applicable Libor rate, plus a margin of 2.25% to 2.75% depending on the percent of the borrowing base utilized at the time of the credit extensionon. We may select Eurodollar loans of one, two, three and six months. A commitment fee of 0.375% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears. There was no commitment fee due at March 31, 2009.

The Credit Facility includes usual and customary affirmative covenants for credit facilities of this type and size, as well as customary negative covenants, including, among others, limitations on liens, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, and investments. The Credit Facility also requires that we, at the end of each fiscal quarter beginning with the quarter ending September 30, 2008, maintain a minimum current assets to current liabilities ratio and a minimum ratio of EBITDA (earnings before interest, taxes, depreciation and amortization) to interest expense and at the end of each fiscal quarter beginning with the quarter ended September 30, 2008 to maintain a minimum ratio of EBITDA to senior funded debt.

Additionally, Texas Capital Bank, N.A. and the holders of the debentures entered into a Subordination Agreement whereby the debentures issued on June 21, 2007 will be subordinated to the Credit Facility.

Debentures

On April 11, 2007, we entered into a Securities Purchase Agreement, Registration Rights Agreements, Senior Secured Debentures, a Pledge and Security Agreement, a Secured Guaranty, and other related agreements (the "Financing Agreements") with the "Buyers" of a new series of senior secured debentures (the "Debentures"). Under the terms of the Financing Agreements, we agreed to sell Debentures for a total purchase price of $9.0 million. In connection with the purchase, we agreed to issue to the Buyers a total of 1,800,000 shares. The first closing occurred on April 12, 2007 with a total of $6.3 million in Debentures being sold and the remaining $2.7 million closing on June 21, 2007.

The Debentures originally had a three-year term, maturing on March 31, 2010, and bear interest at a rate equal to 10% per annum. Interest is payable quarterly in arrears on the first day of each succeeding quarter. We may pay interest in either cash or registered shares of our common stock. The Debentures have no prepayment penalty so long as we maintain an effective registration statement with the Securities Exchange Commission and provided we give six (6) business days prior notice of redemption to the Buyers.

The proceeds from the Debentures were allocated to the long-term debt and the stock issued based on the fair market value of each item that we calculated to be $9.0 million for each item. Since each of the instruments had a value equal to 50% of the total, we allocated $4.5 million to stock and $4.5 million to the note. The loan discount costs of $4.5 million will accrete as interest based on the interest method over the period of issue to maturity or redemption. The amount of interest accreted for the fiscal year ended March 31, 2009 was $2,814,095 and $1,089,798 for the fiscal year ended March 31, 2008. Of the $2,814,095 interest accreted during the period ended March 31, 2009, $2,112,267 relates to the redemption of $6.3 million of the Debentures. The remaining amount of interest to accrete in future periods is $596,108 as of March 31, 2009.

We incurred debt issue costs totaling $466,835. The debt issue costs are initially recorded as assets and are amortized to expense on a straight-line basis over the life of the loan. The amount expensed in the twelve month period ended March 31, 2009 was $268,453. Of this amount, $195,559 was expensed upon the redemption of $6.3 million of the Debentures. The remaining debt issue costs totaling $45,929 will be expensed in the fiscal year ended March 31, 2010.

Effective July 7, 2008, we redeemed an aggregate principal amount of $6.3 million of the Debentures and amended the $2.7 million of aggregate principal amount of the remaining Debentures to, among other things, permit the indebtedness under our new Credit Facility, subordinate the security interests of the debentures to the new Credit Facility, provide for the redemption of the remaining Debentures with the net proceeds from our next debt or equity offering and eliminate the covenant to maintain certain production thresholds.

Pursuant to the terms of the Registration Rights Agreement, as amended, between us and one of the Buyers, we were obligated to register 1,000,000 of the shares issued under the Financing Agreements. These shares were registered effective December 24, 2008.

Convertible and Other Long-Term Debt

On August 3, 2006, we sold a $25,000 convertible note that has an interest rate of 6% and matures August 2, 2010. The note is convertible at any time at the option of the note holder into shares of our common stock at a conversion rate of $10.00 per share.

We financed the purchase of vehicles through a bank. The notes are for seven years and the weighted average interest is 6.99% per annum. Vehicles collateralize these notes.

Long-term debt consists of the following at March 31, 2009:

Credit Facility	$ 7,328,000
Debentures	2,700,000
Unaccreted discount	(596,108)
Debentures, net of unaccreted discount	2,103,892
Vehicle notes payable	109,307
Total long-term debt	9,541,199
Less current portion	(1,723,036)
Long-term debt	$ 7,818,163

Principal amounts are due on long-term and convertible debt as follows: Year ended March 31, 2010 -$1,723,036, March 31, 2011 -$8,377,636, March 31, 2012 -$25,243, March 31, 2013 -$16,044, March 31, 2014 -$13,171 and thereafter-$7,177.

Note 6 – Oil & Gas Properties

On April 9, 2007, we entered into a "Joint Exploration Agreement" with a shareholder, MorMeg, LLC, whereby we agreed to advance $4.0 million to a joint operating account for further development of MorMeg's Black Oaks leaseholds in exchange for a 95% working interest in the Black Oaks Project. We will maintain our 95% working interest until "payout", at which time the MorMeg 5% carried working interest will be converted to a 30% working interest and our working interest becomes 70%. Payout is generally the point in time when the total cumulative revenue from the project equals all of the project's development expenditures and costs associated with funding. Through an additional extension, we have until December 31, 2009 to contribute additional capital toward the Black Oaks Project development. If we elect not to contribute further capital to the Black Oaks Project prior to the project's full development while it is economically viable to do so, or if there is more than a thirty day delay in project activities due to lack of capital, MorMeg has the option to cease further joint development and we will receive an undivided interest in the Black Oaks Project. The extension will have no force and effect, however, upon a material default by EnerJex under the Credit Facility. The undivided interest will be the proportionate amount equal to the amount that our investment bears to our investment plus $2.0 million, with MorMeg receiving an undivided interest in what remains.

In August of 2007, we entered into a development agreement with Euramerica Energy, Inc., or Euramerica, to further the development and expansion of the Gas City Project, which included 6,600 acres, whereby Euramerica contributed $524,000 in capital toward the project. Euramerica was granted an option to purchase this project for $1.2 million with a requirement to invest an additional $2.0 million for project development by August 31, 2008. We were the operator of the project at a cost plus 17.5% basis. We received $600,000 of the $1.2 million purchase price and $500,000 of the $2.0 million development funds. We have recorded a reduction of $600,000 to our oil & gas properties using full-cost accounting subject to amortization as of the year ended March 31, 2009. In January 2009, Euramerica failed to fully fund both the balance of the purchase price and the remaining development capital owed under the agreements between us and Euramerica. Therefore, Euramerica has forfeited all of its interest in the property, including all interests in any wells, improvements or assets, and all of Euramerica's interest in the property reverts back to us. In addition, all operating agreements between us and Euramerica relating to the Gas City Project are null and void. We drilled 22 wells on behalf of Euramerica under the development agreement. We are currently exploring options to sell or further develop the Gas City Project through joint venture partnerships or other opportunities. The gas project remains shut in.

We recorded a non-cash impairment of $4,777,723 to the carrying value of our proved oil and gas properties during the fiscal year ended March 31, 2009. The impairment is primarily attributable to lower prices for both oil and natural gas at December 31, 2008. The charge results from the application of the “ceiling test” under the full cost method of accounting. Under full cost accounting requirements, the carrying value may not exceed an amount equal to the sum of the present value of estimated future net revenues (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. A ceiling test charge occurs when the carrying value of the oil and gas properties exceeds the full cost ceiling.

Note 7 – Related party transactions

In August 2008, we paid $20,000 to a non-employee director and former member of the audit committee for assisting in the establishment and development of the audit committee and for his involvement and assistance to the chief executive officer in finalizing the hedging instrument with BP.

Note 8 – Commitments and Contingencies

We have a lease agreement that expires in September 30, 2013. Future minimum payments are $71,180 for the year ending March 31, 2010.

Note 9 – Income Taxes

Deferred income taxes are determined based on the tax effect of items subject to different treatment between book and tax bases. At March 31, 2009, there is approximately $8,100,000 of net operating loss carry-forwards expiring in 2021-2023. The net deferred tax is as follows:

	March 31, 2009	March 31, 2008
Non-current deferred tax asset:		
Impaired oil & gas costs and long-lived assets	$ 1,864,700	$ 312,800
Net operating loss carry-forward	2,754,600	2,429,900
Valuation allowance	(4,619,300)	(2,742,700)
Total deferred tax net	$ -	$ -

A reconciliation of the provision for income taxes to the statutory federal rate for continuing operations is as follows:

	March 31, 2009	March 31, 2008
Statutory tax rate	34%	34%
Equity based compensation	(1)%	(15)%
Oil & gas costs and long-lived assets	(29)%	1%
Change in valuation allowance	(4)%	(20)%
Effective tax rate	0%	0%

Note 10 – Subsequent Events

In April and May of 2009, we retired $450,000 of the $2.7 million Debentures that were outstanding at March 31, 2009, leaving a remaining balance of $2.25 million as of the date of this report.

Subsequent to year-end, we amended the Debentures to extend the maturity date to September 30, 2010, to allow us to pay interest in either cash or payment-in-kind interest (an increase in the amount of principal due) or payment-in-kind shares (issuance of shares of common stock), and add a provision for the conversion of the debentures into shares of EnerJex's common stock. See Note 5.

We have made Borrowing Base Reduction payments of $200,000 on our Credit Facility.

Note 11 – Supplemental Oil and Natural Gas Reserve Information (Unaudited)

Results of operations from oil and natural gas producing activities

The following table shows the results of operations from the Company's oil and gas producing activities. Results of operations from these activities are determined using historical revenues, production costs and depreciation, depletion and amortization of the capitalized costs subject to amortization. General and administrative expenses, professional, investor relations and interest expense is excluded from this determination.

	March 31, 2009	March 31, 2008
Production revenues	$ 6,436,805	$ 3,602,798
Production costs	(2,637,333)	(1,795,188)
Depletion and depreciation	(892,871)	(913,224)
Results of operations for producing activities	$ 2,906,601	$ 894,386

Capitalized costs of oil and natural gas producing properties

The Company's aggregate capitalized costs related to oil and natural gas producing activities are as follows:

	March 31, 2009	March 31, 2008
Proved	$ 8,566,979	$10,207,596
Unevaluated and unproved	31,183	62,216
Accumulated depreciation and depletion	(1,817,956)	(925,086)
Sale of properties	(300,000)	(300,000)
Net capitalized costs	$ 6,480,206	$ 9,044,726

Unproved and unevaluated properties are not included in the full-cost pool and are therefore not subject to depletion or depreciation. These assets consist primarily of leases that have not been evaluated. We will continue to evaluate our unproved and unevaluated properties; however, the timing of such evaluation has not been determined.

Capitalized costs incurred for oil and natural gas producing activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities that have been capitalized are summarized below:

	March 31, 2009	March 31, 2008
Acquisition of proved and unproved properties	$ 123,040	$4,352,040
Development costs	2,999,963	5,178,281
Exploration costs	-	-
Total	$3,123,003	$9,530,321

Gas and oil Reserve Quantities

Our ownership interests in estimated quantities of proved oil and gas reserves and changes in net proved reserves all of which are located in the United States are summarized below. Proved reserves are estimated quantities of natural gas and oil that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those that are expected to be recovered through existing wells with existing equipment and operating methods. Reserves are stated in thousand cubic feet (mcf) of natural gas and barrels (stb) of oil. Geological and engineering estimates of proved natural gas and oil reserves at one point in time are highly interpretive, inherently imprecise and subject to ongoing revisions that may be substantial in amount. Although every reasonable effort is made to ensure that the reserve estimates are accurate, by their nature reserve estimates are generally less precise than other estimates presented in connection with financial statement disclosures.

	March 31, 2009		March 31, 2008	
	Gas-mcf	Oil-stb	Gas-mcf	Oil-stb
Proved reserves:				
Revisions of previous estimates	(394,732)	(14,575)	-	-
Purchase of minerals in place	-	53,280	418,959	347,228
Extensions and discoveries	-		-	1,068,683
Production	(6,465)	(74,289)	(17,762)	(43,697)
Total	-	1,336,630	401,197	1,372,214

Proved developed reserves at the end of the period:

Gas- mcf	Oil – stb
March 31, 2009	March 31, 2009
-	524,980

Gas- mcf	Oil stb
March 31, 2008	March 31, 2008
401,197	861,240

Standardized measure of discounted future net cash flows

The standardized measure of discounted future net cash flows from our proved reserves for the periods presented in the financial statements is summarized below. The standardized measure of future cash flows as of March 31, 2009 and 2008 is calculated using a price per Mcf of gas of $0 and $7.479, respectively and a price for oil of $42.65 and $94.53, respectively. The resulting estimated future cash inflows are reduced by estimated future costs to develop and produce the estimated proved reserves. These costs are based on year-end cost levels. Future income taxes are based on year-end statutory rates. The future net cash flows are reduced to present value by applying a 10% discount rate. The standardized measure of discounted future cash flows is not intended to represent the replacement cost or fair market value of the Company's oil and gas properties.

	March 31, 2009	March 31, 2008
Future production revenue	$ 57,007,970	$132,457,459
Future production costs	(24,732,440)	(39,629,625)
Future development costs	(9,584,500)	(18,827,013)
Future cash flows before income taxes	22,691,030	74,000,821
Future income taxes	-	(19,241,954)
Future net cash flows	22,691,030	54,758,867
10% annual discount for estimating of future cash flows	(12,061,690)	(26,558,364)
Standardized measure of discounted net cash flows	$ 10,629,340	$ 28,200,503

Changes in Standardized Measure of Discounted Future Net Cash Flows

	March 31, 2009	March 31, 2008
Balance beginning of year	$ 28,200,503	$ -
Sales, net of production costs	(5,697,410)	(1,777,278)
Net change in pricing and production costs	(31,927,063)	-
Net change in future estimated development costs	9,220,510	-
Purchase of minerals in place	136,190	8,124,394
Extensions and discoveries	518,297	21,853,387
Revisions	(1,089,039)	-
Accretion of discount	(143,477)	-
Change in income tax	11,410,829	-
Balance end of year	$ 10,629,340	$28,200,503