PetroHunter Energy Corp
Form S-1
June 30, 2008

As filed June 30, 2008 File No. 333-______

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

FORM S-1
REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

PetroHunter Energy Corporation
(Exact name of registrant as specified in its charter)

Maryland	1311	98-0431245
(State or jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification No.)

1600 Stout Street, Suite 2000
Denver, Colorado 80202
(303) 572-8900; (720) 889-8371 fax
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Charles B. Crowell, Chairman and Chief Executive Officer
1600 Stout Street, Suite 2000
Denver, Colorado 80202
(303) 572-8900; (720) 889-8371 fax
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies of all communications to:
Fay M. Matsukage, Esq.
Dill Dill Carr Stonbraker & Hutchings, P.C.
455 Sherman Street, Suite 300
Denver, Colorado 80203
(303) 777-3737; (303) 777-3823 fax

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of the Registration Statement.

If any of the securities registered on this Form are being offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. [X]

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. 9 _________

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. 9 _________

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. 9 ____________

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 "small reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [ ]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [X]

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	Amount to be registered (1)	Proposed maximum offering price per unit	Proposed maximum aggregate offering price	Amount of registration fee
Common stock, $0.001 par value per share, issuable upon exercise of warrants	34,442,500 shares	$1.00 (2)	$34,442,500 (2)	$1,353.59
Common stock, $0.001 par value per share, issuable upon exercise of warrants	48,230,950 shares	$0.25 - $0.28 (2)	$12,610,716 (2)	$495.60
Common stock, $0.001 par value per share	400,000 shares	$0.20 (3)	$80,000 (3)	$3.14
Common stock, $0.001 par value per share	18,917,109 shares	$0.20 (3)	$3,783,422 (3)	$148.69
	101,990,559 shares		$50,916,638	$2,001.02

(1) Pursuant to Rule 416 of the Securities Act of 1933, as amended, this registration statement also covers such additional number of shares of common stock that may become issuable as a result of any stock splits, stock dividends, or other similar transactions.

(2) Pursuant to Rule 457(g) of the Securities Act of 1933, as amended, the registration fee has been calculated using the price at which the warrants may be exercised.

(3) Estimated pursuant to Rule 457(c) solely for the purpose of calculating the registration fee, based upon the average of the bid and asked prices for such shares of common stock on June 26, 2008, as reported by the OTC Bulletin Board.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to Completion, Dated June 30, 2008

PetroHunter Energy Corporation
Up to 101,990,559 Shares of Common Stock

Unless the context otherwise requires, the terms “we”, “our” and “us” refers to PetroHunter Energy Corporation.

This prospectus relates to the resale by selling stockholders of up to 101,990,559 shares of common stock. We will not receive any proceeds from sale of any of the shares offered by the selling stockholders. We will pay the expenses of registering these shares.

Our common stock is traded on the OTC Bulletin Board under the symbol “PHUN.OB.” On June 27, 2008, the closing bid price for our common stock was $0.20 per share.

Investing in these securities involves a high degree of risk. A detailed explanation of these risks is included in the section entitled “Risk Factors” of this prospectus, beginning on page 5.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

____________, 2008

TABLE OF CONTENTS

PROSPECTUS SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should carefully read this entire prospectus and the financial statements contained in this prospectus before purchasing our securities.

PetroHunter Energy Corporation

PetroHunter Energy Corporation (collectively, with its subsidiaries, referred to herein as “PetroHunter”, “Company”, “we”, “us” or “our”) is a development stage global oil and gas exploration and production company committed to acquiring and developing primarily unconventional natural gas and oil prospects that we believe have a very high probability of economic success. Since our inception in 2005, our principal business activities have been raising capital through the sale of common stock and convertible notes and acquiring oil and gas properties in the western United States and Australia. Currently, we own property in Colorado, where we have drilled five wells on our Buckskin Mesa property, Australia, where we have drilled one well on our property in the Northern Territory, and in Montana, where we hold a land position in the Bear Creek area. The wells on these properties have not yet commenced oil production. We also have working interests in eight additional wells in Colorado which are operated by EnCana Oil & Gas USA (“EnCana”). In November 2007, we sold 66,000 net acres of land and two wells in Montana and 177,445 net acres of land in Utah, and in May 2008, we sold 625 net acres of land and 16 wells in the Southern Piceance in Colorado, allowing us to focus on our Buckskin Mesa property and Australia.

Our principal executive offices are located at 1600 Stout Street, Suite 2000, Denver, CO 80202. The telephone number is (303) 572-8900, the facsimile number is (303) 572-8927, and our web site is www.petrohunter.com. Information contained in our website is not part of this prospectus.

The Offering

Securities offered	101,990,559 shares of common stock.
Use of proceeds	We will not receive any of the proceeds from the selling stockholders of shares of our common stock.
Securities outstanding	338,065,950 shares of common stock as of June 27, 2008.
Plan of distribution	The offering is made by the selling stockholders named in this prospectus, to the extent they sell shares. Sales may be made in the open market or in private negotiated transactions, at fixed or negotiated prices. See “Plan of Distribution.”

Risk Factors

Investing in our securities involves a high degree of risk. You should consider carefully the information under the caption “Risk Factors” in deciding whether to purchase the shares.

Summary Financial Information

The following summary financial data is derived from the interim (unaudited) financial statements for the six months ended March 31, 2008 and 2007 and audited financial statements for the fiscal years ended September 30, 2007 and 2006 and the period from inception (June 20, 2005) through September 30, 2005.

We have prepared the financial statements in accordance with generally accepted accounting principles. You should read this summary financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Business," and our financial statements.

STATEMENT OF OPERATIONS DATA

	Six Months Ended March 31, 2008	Six Months Ended March 31, 2007 (restated)	Year Ended September 30, 2007	Year Ended September 30, 2006	From Inception (June 20, 2005) to September 30, 2005	Cumulative from Inception (June 20, 2005) to March 31, 2008
	($ in thousands, except per share amounts)					
Total Revenues	$ 992	$ 1,338	$ 2,820	$ 36	$ --	$ 3,848
Total Operating Expenses	$ 6,371	$ 20,442	$ 45,981	$ 18,245	$ 2,096	$ 72,693
Loss from Operations	$ (5,379)	$ (19,104)	$ (43,161)	$ (18,209)	$ (2,096)	$ (68,845)
Total Other Expense	$ (10,374)	$ (2,217)	$ (6,650)	$ (2,483)	$ (23)	$ (19,530)
Net Loss	$ (15,753)	$ (21,321)	$ (49,811)	$ (20,692)	$ (2,119)	$ (88,375)
Net Loss per Common Share – Basic and Diluted	$ (0.05)	$ (0.10)	$ (0.20)	$ (0.14)	$ (0.02)	

BALANCE SHEET DATA

	March 31, 2008	September 30, 2007	September 30, 2006	September 30, 2005
	($ in thousands, except per share amounts)			
Working (Deficit) Capital	$ (39,773)	$ (37,865)	$ 1,275	$ 8,438
Oil and Gas Properties, Net	$ 173,975	$ 162,843	$ 45,973	7,231
Total Assets	$ 181,537	$ 182,024	$ 59,242	$ 8,500
Non-Current Liabilities	$ 34,601	$ 37,130	$ 522	$ --
Stockholders' Equity (Deficit)	$ 105,143	$ 100,324	$ 48,353	$ (1,196)

GLOSSARY

Unless otherwise indicated in this document, oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids so that six Mcf of natural gas are referred to as one barrel of oil equivalent.

API Gravity. A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density of various petroleum liquids, expressed in degrees. API gravity is gradated in degrees on a hydrometer instrument and was designed so that most values would fall between 10° and 70° API gravity. The arbitrary formula used to obtain this effect is: API gravity = (141.5/SG at 60°F) — 131.5, where SG is the specific gravity of the fluid.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas at standard atmospheric conditions.

Capital Expenditures. Costs associated with exploratory and development drilling (including exploratory dry holes); leasehold acquisitions; seismic data acquisitions; geological, geophysical and land-related overhead expenditures; delay rentals; producing property acquisitions; other miscellaneous capital expenditures; compression equipment and pipeline costs.

Carried Interest. The owner of this type of interest in the drilling of a well incurs no liability for costs associated with the well until the well is drilled, completed and connected to commercial production/processing facilities.

Completion. The installation of permanent equipment for the production of oil or natural gas.

Developed Acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development Well. A well drilled within the proved area of an oil or natural gas reservoir to a depth that is known to be productive.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology.

Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Farm-In or Farm-Out. An agreement under which the owner of a working interest in a natural gas and oil lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farm-in” while the interest transferred by the assignor is a “farm-out”.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Finding and Development Costs. The total capital expenditures, including acquisition costs and exploration and abandonment costs, for oil and gas activities divided by the amount of proved reserves added in the specified period.

Force Pooling. The process by which interests not voluntarily participating in the drilling of a well, may be involuntarily committed to the operator of the well (by a regulatory agency) for the purpose of allocating costs and revenues attributable to such well.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

Lease. An instrument which grants to another (the lessee) the exclusive right to enter to explore for, drill for, produce, store and remove oil and natural gas on the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing.

Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions.

MCFE. One thousand cubic feet of gas equivalent. Gas equivalents are determined using the ratio of six Mcf of gas (including gas liquids) to one Bbl of oil.

Net Acres or Net Wells. A net acre or well is deemed to exist when the sum of our fractional ownership working interests in gross acres or wells, as the case may be, equals one. The number of net acres or wells is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof.

Operator. The individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease.

Overriding Royalty. A revenue interest in oil and gas, created out of a working interest which entitles the owner to a share of the proceeds from gross production, free of any operating or production costs.

Payout. The point at which all costs of leasing, exploring, drilling and operating have been recovered from production of a well or wells, as defined by contractual agreement.

Productive Well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes. Productive wells consist of producing wells and wells capable of productions, but specifically exclude wells drilled and cased during the fiscal year that have yet to be tested for completion.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved Reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Reserves. Natural gas and crude oil, condensate and natural gas liquids on a net revenue interest basis, found to be commercially recoverable.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage, or of the proceeds of the sale thereof, but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Spud. To start the well drilling process by removing rock, dirt and other sedimentary material.

Stratigraphic. Relating to vertical position in a rock column. More generally, relating to relative geological age, since typically, in any given sequence of sedimentary rock, older rock is lower than newer.

3-D Seismic. The method by which a three-dimensional image of the earth's subsurface is created through the interpretation of a reflection of seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production.

Undeveloped Acreage. Lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this prospectus constitute “forward-looking statements.” These statements, identified by words such as “plan,” “anticipate,” “believe,” “estimate,” “should,” “expect” and similar expressions include our expectatio and objectives regarding our future financial position, operating results and business strategy. These statements reflect the current views of management with respect to future events and are subject to risks, uncertainties and other factors that may cause our actual results, performance or achievements, or industry results, to be materially different from those described in the forward-looking statements. All forward-looking statements herein as well as all subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by cautionary statements set forth in “Risk Factors” appearing below. We assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise. We advise you to carefully review the reports and documents we file from time to time with the Securities and Exchange Commission (the “SEC”).

RISK FACTORS

Before deciding to invest in us or to maintain or increase your investment, you should carefully consider the risk factors described below that discuss the material risks related to an investment in us, together with all other information in this prospectus and in our other filings with the SEC, before making an investment decision. If any of the following risks actually occurs, our business, financial conditions or operating results could be materially adversely affected. In such case, the trading price of our common stock could decline, and you may lose all or part of your investment.

Risks Related to Our Business

We have a limited operating history and have generated only very limited revenues. We have incurred significant losses and will continue to incur losses for the foreseeable future.

We are a development stage oil and gas company and have limited operating history and production revenue. Our principal activities have been oil and gas drilling and development activities, raising capital through the sale of our securities and identifying and evaluating potential oil and gas properties.

The report of our independent registered public accounting firm on the financial statements for the year ended September 30, 2007, includes an explanatory paragraph relating to the uncertainty of our ability to continue as a going concern. We have incurred a cumulative net loss of $88.4 million for the period from inception (June 20, 2005) to March 31, 2008. As of March 31, 2008, we had a working capital deficit of approximately $39.8 million, are in default on certain obligations, are not in compliance with the covenants of several loan agreements, and require significant additional funding to sustain our operations and satisfy our contractual obligations for our planned oil and gas exploration and development operations.   We have had multiple property liens and foreclosure actions filed by vendors, some of whom have begun foreclosure proceedings, and have significant capital expenditure commitments. For the 2008 fiscal year, we do not expect our operations to generate sufficient cash flows to provide working capital to cover overhead, the funding of our lease acquisitions, and the exploration and development of our properties. Without adequate financing, we may not be able to successfully develop prospects that we have or that we acquire and we may not achieve profitability from operations in the near future or at all.

Our short-term cash commitments require us to sell more debt and/or equity securities and/or sell our assets, which may be detrimental to our stockholders.

As of March 31, 2008, we had drilling commitments for the fiscal year ending September 30, 2008 of $44 million. We will raise additional funds to meet these obligations by selling debt and/or equity securities, by selling assets, or by entering into farm-out agreements or other similar types of arrangements. Financing obtained through the sale of our equity will result in significant dilution to our stockholders. We have granted security interests in our assets to lenders and holders of our debentures which limits our ability to sell debt securities since they will be subordinated to our other security interest holders. The existence of security interests in our assets restricts our ability to sell those assets. We may be forced to sell assets at below market value, and therefore we may not realize the market value or even the carrying value of those assets.

The lack of production and established reserves for our properties impairs our ability to raise capital.

As of September 30, 2007, we have established very limited production of natural gas from a limited number of wells, and have a limited number of properties for which reserves have been established, making it more difficult to raise the amount of capital needed to fully exploit the production potential of our properties. Therefore, we may have to raise capital on terms less favorable than we would desire; this may result in increased dilution to existing stockholders.

Terms of subsequent financings may adversely impact your investment.

We may have to engage in common equity, debt or preferred stock financing in the future. Stockholders' rights and the value of their investment in the common stock could be reduced by any type of financing we do. Interest on debt securities could increase costs and negatively impact operating results, and investors in debt securities may negotiate for other consideration or terms that could have a negative impact on the investment of existing stockholders. Preferred stock could be issued in series from time to time with such designations, rights, preferences and limitations as needed to raise capital, and the terms of preferred stock could be more advantageous to those investors than to the holders of common stock. If we need to raise more equity capital from the sale of common stock, institutional or other investors may negotiate terms at least as, and possibly more favorable than, the terms of the investment of existing stockholders. In addition, any shares of common stock that we sell could be sold into the market and subsequent sales could adversely affect the market price of our stock.

Marc A. Bruner and his affiliates control a significant percentage of our outstanding common stock, which will enable them to control many significant corporate actions and may prevent a change in control that would otherwise be beneficial to our stockholders.

Marc A. Bruner beneficially owned approximately 43% of our common stock as of June 27, 2008. Such control by Mr. Bruner may have a substantial impact on matters requiring the vote of common stockholders, including the election of our directors and most of our corporate actions. Such control could delay, defer or prevent others from initiating a potential merger, takeover or other change in control that might benefit us and our stockholders. Such control could adversely affect the voting and other rights of our other stockholders and could depress the market price of our common stock.

Marc A. Bruner is the controlling owner of MAB Resources LLC ("MAB"), the entity with which we have an agreement under which MAB is entitled to an overriding royalty interest on certain of our oil and gas properties. Mr. Bruner serves as the chairman of the board of Gasco Energy, Inc., a company whose stock is trading on the American Stock Exchange, and chairman of the board, chief executive officer and president of Falcon Oil & Gas Ltd. ("Falcon"), a company whose stock is traded on the TSX Venture Exchange, and is involved with other natural resource companies. He is a significant stockholder of Galaxy Energy Corporation, a company whose stock is traded on the OTC Bulletin Board. Mr. Bruner is also a significant stockholder of Exxel Energy Corp., a British Columbia corporation, whose stock is traded on the TSX Venture Exchange.

8

The issuance of the shares upon conversion of convertible debentures and exercise of warrants could significantly dilute the interests of stockholders.

In November 2007, we issued convertible debentures in the aggregate principal amount of approximately $7.0 million. The debentures are convertible into shares of our common stock at any time prior to their maturity dates at a current conversion price of $0.15, subject to adjustments for stock splits, stock dividends, stock combinations and other similar transactions. The conversion prices of the convertible debentures could be further lowered, perhaps significantly, in the event of our issuance of common stock below the convertible debentures' conversion price, either directly or in connection with the issuance of securities that are convertible into, or exercisable for, shares of our common stock.

In addition, we issued five-year warrants to the holders of the convertible debentures. The warrant holders are entitled to purchase an aggregate of 48.2 million shares of our common stock at an exercise price ranging from $0.24 to $0.28 per share. Both the number of warrants and the exercise price are subject to adjustments that could make them further dilutive to our stockholders.

Neither the convertible debentures nor the warrants establish a "floor" that would limit reductions in the conversion price of the convertible debentures or the exercise price of the warrants that may occur under certain circumstances. Correspondingly, there is no "ceiling" on the number of shares that may be issuable under certain circumstances under the anti-dilution adjustment in the convertible debentures and warrants. Accordingly, our issuance of the convertible debentures and warrants could significantly dilute the interests of our stockholders.

Our failure to satisfy our registration, listing and other obligations with respect to the common stock underlying the warrants could result in adverse consequences, including acceleration of the convertible debentures.

We are required to maintain the effectiveness of the registration statement covering the resale of the common stock underlying the warrants, until the earlier of the date the underlying common stock may be resold pursuant to Rule 144 under the Securities Act of 1933 without any type of restriction or the date on which the sale of all the underlying common stock is completed, subject to certain exceptions. We will be subject to various penalties for failing to meet our registration obligations, which include cash penalties and the forced redemption of the convertible debentures.

The issuance of shares upon exercise of outstanding warrants and options may cause immediate and significant dilution to our existing stockholders.

As of March 31, 2008, we have issued warrants and options to purchase a total of 169.3 million shares of common stock. In November 2007, we sold convertible debentures that are convertible into a total of 46.4 million shares of common stock. The issuance of shares upon exercise of warrants and options and upon conversion of debentures may result in significant dilution to the interests of our existing stockholders.

We are obligated to make significant periodic payments of interest under our credit facilities.

As of March 31, 2008, we have drawn down $32.8 million on our credit facilities. Interest on the credit facility borrowings accrues at 6.75% over the prime rate and is payable quarterly. If the prime rate remains at 7.25% and we take no additional draws, our required interest payment will be $4.4 million during the 2008 fiscal year. As of March 31, 2008, we were in default of payments in the amount of $3.9 million, consisting of interest and fees owed to the lender. The lender has waived and released us from any and all defaults, failures to perform, and any other failures to meet our obligations through July 1, 2009. If we default on our payment obligations in the future, the lender will have all rights available under the instrument, including acceleration, termination and enforcement of its security interest in our Buckskin Mesa project in the Piceance Basin, Colorado.

9

We are in default in relation to numerous provisions under our convertible debentures and other debt and credit arrangements, which could bring material adverse consequences to our business.

As of March 31, 2008, we were in default in relation to various terms, covenants and conditions, including provisions relating to the payment of principal and interest toward our debt obligations and credit facilities. Although we believe we have obtained sufficient waivers and releases from the holders of these instruments, there can be no assurance that the continuation of such events of default, failures to perform and other failures to meet the terms of these instruments will not result in the holders of these instruments taking any and all actions afforded them under these agreements in collecting amounts owed to them. Such actions could include, and are not limited to, acceleration, termination, and foreclosure actions in relation to any underlying collateral, and could result in the holders pursuing involuntary bankruptcy proceedings against us.

We have been and continue to be delinquent in paying certain trade creditor obligations to our vendors, who have historically filed liens on our properties and taken other legal actions against us in order to collect amounts owed to them by us, which could bring material adverse consequences to our business.

In conjunction with the closing of the Laramie transaction in May 2008, we have settled or otherwise resolved numerous claims, liens and other courses of action brought or potentially brought by our U.S. based trade vendors. Although these settlements, primarily through the payment of cash from the proceeds from the sale of assets to Laramie, have substantially reduced our past due trade obligations, there can be no assurance such conditions could not arise again due to our inability to pay future amounts due to our trade vendors. In addition, we continue to have substantial unpaid and past due obligations with our Australian vendors, and we are in the process of attempting to resolve asserted, pending and potential claims with them. Regardless of our ability to successfully resolve these past due obligations, we may be unable to maintain ongoing business relationships with these vendors, which could have a material adverse effect on our business.

We continue to experience significant cash flow challenges, and absent our ability to continue to secure adequate funding to meet our cash obligations, we will not be able to continue in existence.

As of March 31, 2008, we have earned oil and gas revenue from our initial operating wells, but will require significant additional funding to sustain operations and satisfy contractual obligations for planned oil and gas exploration, development and operations in the future. These factors, among others, may indicate that we may be unable to continue in existence. Management believes that we can be successful in obtaining equity and/or debt financing and/or sell interests in some of our properties, which will enable us to continue in existence and establish ourselves as a going concern. While we have raised approximately $102.4 million through March 31, 2008 through issuances of common stock and convertible and other debt, we cannot assure you that we can continue to raise additional funding.

Our officers, directors and advisors are engaged in other businesses, which may result in conflicts of interest.

Certain of our officers, directors, and advisors also serve as directors of other companies or have significant shareholdings in other companies. To the extent that such other companies participate in ventures in which we may participate, or compete for prospects or financial resources with us, these officers and directors will have a conflict of interest in negotiating and concluding terms relating to the extent of such participation. In the event that such a conflict of interest arises at a meeting of the Board of Directors, a director who has such a conflict must disclose the nature and extent of his interest to the Board of Directors and abstain from voting for or against the approval of such participation or such terms.

We depend on a limited number of key personnel who would be difficult to replace.

We depend on the performance of our executive officers and other key employees. The loss of any member of our senior management or other key employees could negatively impact our ability to execute our strategy. We do not maintain key person life insurance policies on any of our employees.

Reserve estimates depend on many assumptions that may turn out to be inconclusive, subject to varying interpretations or inaccurate.

Estimates of natural gas and oil reserves are based upon various assumptions, including assumptions relating to natural gas and oil prices, drilling and operating expenses, capital expenditures, ownership and title, taxes and the availability of funds. The process of estimating natural gas and oil reserves is complex. It requires interpretations of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual natural gas and oil prices, future production, revenues, operating expenses, taxes, development expenditures and quantities of recoverable natural gas will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of future net revenues at any time. A reduction in natural gas and oil prices, for example, would reduce the value of reserves and reduce the amount of natural gas and oil that could be economically produced, thereby reducing the quantity of reserves. At any time, there might be adjustments of estimates of reserves to reflect production history, results of exploration and development, prevailing natural gas prices and other factors, many of which are beyond our control.

Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. Any reserve data assumes that we will make these capital expenditures necessary to develop our reserves. To the extent that we have prepared estimates of our natural gas and oil reserves and of the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

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

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

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil-bearing structures or favorable stratigraphy, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable geoscientists to know whether hydrocarbons are, in fact, present in those structures. We are employing 2-D and 3-D seismic technology for certain of our projects. The use of 2-D and 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and the profitability of our ventures may be adversely affected. Even with the use of advanced seismic applications, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 2-D and 3-D seismic over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in a prospective area. If we are unable to lease those locations on acceptable terms, we will have made substantial expenditures to acquire and analyze 2-D and 3-D data without having an opportunity to attempt to benefit from those expenditures.

Substantially all of our producing properties are located in the Rocky Mountains, making us vulnerable to risks associated with operating in one major geographic area.

Our operations are focused on the Rocky Mountain region and therefore our producing properties are geographically concentrated in that area. In addition, a significant portion of our oil and natural gas resources and operations are located in the Piceance Basin, Colorado and the Northern Territory, Australia. As a result, we may be disproportionately exposed to the effect of delays or interruptions of production from these areas caused by significant governmental regulation, transportation capacity constraints, the availability and capacity of compression and gas processing facilities, curtailment of production or interruption of transportation of natural gas produced from the wells in these areas, as well as the remoteness and lack of infrastructure in the case of the Australian properties.

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

Oil and natural gas operations in the Rocky Mountains and in Australia are adversely affected by seasonal weather conditions and lease stipulations designed to regulate land use, including operating guidelines for designated wildlife habitats and areas with scenic resource value. In certain areas in Australia and on federal lands in the U.S., drilling and other oil and natural gas activities can only be conducted during limited times of the year. This limits our ability to operate in those areas and can intensify competition during those times for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Acquisitions are a part of our business strategy and are subject to the risks and uncertainties of evaluating recoverable reserves and potential liabilities. Properties that we buy may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.

One of our growth strategies is to capitalize on opportunistic acquisitions of oil and natural gas reserves. The successful acquisition of producing and non-producing properties requires an assessment of a number of factors. These factors include recoverable reserves, future oil and gas prices, operating costs, potential environmental and other liabilities, title issues and other factors. Our reviews of acquired properties are inherently incomplete, because it generally is not feasible to perform an in depth review of every individual property involved in each acquisition. Ordinarily, we focus our review efforts on the higher value properties and sample the remainder. However, even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to fully assess their deficiencies or their potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. We sometimes knowingly assume certain environmental and other risks and liabilities in connection with acquired properties. It is possible that our future acquisition activity will result in disappointing results. We could be subject to significant liabilities related to acquisitions

In addition, there is strong competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to pursue our acquisition strategy may be hindered if we are unable to obtain financing or regulatory approvals.

Acquisitions often pose integration risks and difficulties. In connection with future acquisitions, the process of integrating acquired operations into our existing operations may result in unforeseen operating difficulties and may require significant management attention and financial resources that would otherwise be available for the ongoing development or expansion of existing operations. Possible future acquisitions could result in our incurring additional debt, contingent liabilities and expenses, all of which could have a material adverse effect on our financial condition and operating results.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

A portion of our business activities are conducted through joint operating agreements under which we own partial interests in oil and natural gas properties. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others, therefore, depends upon a number of factors outside of our control, including the operator's deployment of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in certain wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from oil and natural gas sales or joint interest to third parties in the energy industry. This concentration of customers and joint interest owners may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, potential oil and natural gas hedging arrangements may expose us to credit risk in the event of nonperformance by counterparties.

Market conditions or operation impediments may hinder our access to natural gas and oil markets or delay our production.

The marketability of our production depends in part upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities. The dependence is heightened where the infrastructure is less developed. Therefore, if drilling results are positive in certain areas, a new gathering system may need to be built to handle the potential volume of gas produced. We might be required to shut in wells, at least temporarily, for lack of a market or because of the inadequacy or unavailability of transportation facilities. If that were to occur, we would be unable to realize revenue from those wells until arrangements were made to deliver production to the market.

Our ability to produce and market natural gas and oil is affected and also may be harmed by:

- the lack of pipeline transmission facilities or carrying capacity;
- government regulation of natural gas and oil production;
- government transportation, tax and energy policies;
- changes in supply and demand; and
- general economic conditions.

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

If we incur indebtedness, our ability to meet our debt obligations and reduce our level of indebtedness will depend on future performance. General economic conditions, oil and gas prices and financial, business and other factors affect our operations and future performance; many of these factors are beyond our control. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt or that future working capital, borrowings or equity financing will be available to pay for or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and performance at the time we need capital. We cannot assure you that we will have sufficient funds to make refund debt payments. Lack of sufficient funds and/or the inability to negotiate new borrowing terms may cause us to sell significant assets which could have a material adverse effect on our business and financial results.

We have found material weaknesses in our internal controls that require remediation and concluded that our internal controls over financial reporting at March 31, 2008, were not effective.

In our filings with the Securities and Exchange Commission, we have reported the existence of continuing material weaknesses related to our control environment which did not sufficiently promote effective internal control over financial reporting through our management structure to prevent a material misstatement from occurring. Specifically, management did not have an adequate process for monitoring accounting and financial reporting and had not conducted a comprehensive review of account balances and transactions that had occurred throughout the year. Our disclosure controls and accounting processes lack adequate staff and procedures in order to be effective. We have not had adequate staffing to provide for an effective segregation of duties, or to adequately identify and resolve accounting issues and provide information to our auditors on a timely basis. These material weaknesses continued to exist as of March 31, 2008; however, we have taken steps to retain additional senior financial consultants to assist us in completing our remediation of these material weaknesses on an accelerated basis.

We are fully committed to remediating the material weaknesses described above and believe that the steps we are taking, including the active involvement of our Audit Committee in the remediation planning and implementation, will properly address these issues. However, while we are taking immediate steps and dedicating substantial resources to correct these material weaknesses, any new controls we implement must operate for a period of time and be tested before a determination can be made as to their effectiveness. Also, our remediation procedures have identified several errors in our previously issued financial statements, which have resulted in an aggregate overstatement of our first quarter net loss by $0.0 million, and an offsetting understatement of our second quarter net loss by the same amount, as more fully described in our consolidated financial statements. As we continue to proceed through our remediation process, we may discover additional past, ongoing or future material weaknesses or significant deficiencies in our financial reporting processes, or additional errors in our financial statements, some of which could be material.

Likewise, our failure to remediate any material weaknesses or significant deficiencies, or a difficulty encountered in their implementation, could result in, among other things: an inability to provide timely and reliable financial information, an inability to meet our reporting obligations with governing bodies such as the Securities and Exchange Commission, loss of investor confidence in our reported financial information leading to a lower trading price for our common shares, additional costs to remediate and implement effective internal controls, or restatements of previously-issued financial statements, any of which could have a material adverse effect on our business, results of operations, or financial condition.

Pending the successful implementation and testing of new controls, we are performing mitigating procedures which we believe are sufficient until such new controls have been implemented.

We have significant future capital requirements. If these obligations are not met, our growth and operations could be limited or suspended indefinitely.

Our future growth depends on our ability to cause the development of the working interests we have acquired, and such development will require the expenditure of large capital either by us or by third parties through farm-out agreements. In addition, we may acquire interests in additional oil and gas leases where we will be required to pay for a specific amount of the initial costs and expenses related to the development of those leases. We intend to finance our foreseeable capital expenditures through sales of non-core assets, farm-out agreements, private placements of debt or equity, and additional funding for which we have no commitments at this time. Future cash flow and the availability of financing will be subject to a number of variables, such as:

- the success of exploration and development on our leases;

- success in locating and producing new reserves; and
- prices of natural gas and oil.

Additional financing sources will be required in the future to fund developmental and exploratory drilling. Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. Additional debt financing could lead to:

- a substantial portion of operating cash flow being dedicated to the payment of principal and interest;
- the Company being more vulnerable to competitive pressures and economic downturns; and
- restrictions on our operations.

Financing might not be available in the future, or we might not be able to obtain necessary financing on acceptable terms, if at all. If sufficient capital resources are not available, we might be forced to curtail drilling and other activities or be forced to sell assets on an untimely or unfavorable basis, which would have an adverse effect on our business, financial condition and results of operations.

Our leases and/or future properties might not produce as anticipated, and we might not be able to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them, which could cause us to incur losses.

Although we have reviewed and evaluated our leases in a manner consistent with standard industry practices, our review and evaluation may not reveal all existing or potential problems. These same factors apply to future acquisitions to be made by us. We may not perform inspections on every well, and environmental issues may not be observable during an inspection. When problems are identified, a seller may be unwilling or unable to provide effective contractual protection against those problems, and we may assume environmental and other risks and liabilities in connection with the acquired properties.

We do not plan to insure against all potential operating risks. We might incur substantial losses and be subject to substantial liability claims as a result of our natural gas and oil operations.

We do not intend to insure against all risks. We intend to maintain insurance against various losses and liabilities arising from operations in accordance with customary industry practices and in amounts that management believes to be prudent. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations. Our natural gas and oil exploration and production activities are subject to hazards and risks associated with drilling for, producing and transporting natural gas and oil, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of natural gas, oil, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

Any of these hazards could have a material adverse effect on our ability to conduct operations and may result in substantial losses. We may elect not to obtain insurance in the event that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could have a material adverse effect on our business, financial condition and results of operations.

Risks Relating to the Oil and Gas Industry

A substantial or extended decline in natural gas and oil prices may adversely affect our ability to meet our capital expenditure obligations and financial commitments.

Our revenues, operating results and future rate of growth are substantially dependent upon the prevailing prices of, and demand for, natural gas and oil. Declines in the prices of, or demand for, natural gas and oil may adversely affect our financial condition, liquidity, ability to finance planned capital expenditures and results of operations. Lower natural gas and oil prices may also reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, and they are likely to continue to be volatile in the future. A decrease in natural gas or oil prices will not only reduce revenues and profits, but will also reduce the quantities of reserves that are commercially recoverable and may result in charges to earnings for impairment in the value of assets. If natural gas or oil prices decline significantly for extended periods of time in the future, we might not be able to generate enough cash flow from operations to meet our obligations and make planned capital expenditures. Natural gas and oil prices are subject to wide fluctuations in response to relatively minor changes in the supply of, and demand for, natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. Among the factors that could cause this fluctuation are:

- changes in supply and demand for natural gas and oil;
- levels of production and other activities of the Organization of Petroleum Exporting Countries, or OPEC, and other natural gas and oil producing nations;
- market expectations about future prices;
- the level of global natural gas and oil exploration, production activity and inventories;
- political conditions, including embargoes, in or affecting other oil producing activity; and
- the price and availability of alternative fuels.

Lower natural gas and oil prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of natural gas and oil that we are able to produce economically. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas and oil are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future success depends on the success of our exploration, development and production activities. Such activities are subject to numerous risks beyond our control, including the risk that we will not find commercially productive natural gas or oil reservoirs. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretation. The cost of drilling, completing and operating wells is often uncertain before drilling commences.
Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or prevent drilling operations, including:

- unexpected drilling conditions;

- pressure or irregularities in geological formations;
- equipment failures or accidents;
- pipeline and processing interruptions or unavailability;
- title problems;
- lack of market demand for natural gas and oil;
- delays imposed by or resulting from compliance with environmental and other regulatory requirements;
- shortages of or delays in the availability of drilling rigs and the delivery of equipment; and
- reductions in natural gas and oil prices.

Our future drilling activities might not be successful, and the drilling success rate overall or within a particular area could decline. We could incur losses by drilling unproductive wells. Although we have identified numerous potential drilling locations, we cannot be sure that we will ever drill them or will produce natural gas or oil from them or from any other potential drilling locations. Shut-in wells, curtailed production and other production interruptions may negatively impact our business and result in decreased revenues.

Competition in the oil and gas industry is intense, and many of our competitors have greater financial, technological and other resources than we do, which may adversely affect our ability to compete.

We operate in the highly competitive areas of oil and gas exploration, development and acquisition with a substantial number of other companies. We face intense competition from independent, technology-driven companies as well as from both major and other independent oil and gas companies in each of the following areas:

- seeking oil and gas exploration licenses and production licenses;
- acquiring desirable producing properties or new leases for future exploration;
- marketing natural gas and oil production;
- integrating new technologies;
- acquiring the equipment and expertise necessary to develop and operate properties; and
- hiring and retaining a staff of competent technical and administrative professionals.

Many of our competitors have substantially greater financial, managerial, technological and other resources. These companies might be able to pay more for exploratory prospects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. To the extent competitors are able to pay more for properties than we are able to afford, we will be at a competitive disadvantage. Further, many competitors may enjoy technological advantages and may be able to implement new technologies more rapidly. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend upon our ability to successfully conduct operations, implement advanced technologies, evaluate and select suitable properties and consummate transactions in this highly competitive environment.

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

In periods of increased drilling activity, shortages of drilling and completion rigs, field equipment and qualified personnel could develop. From time to time, these costs have sharply increased in various areas around the world and could do so again. The demand for and wage rates of qualified drilling rig crews generally rise in response to the increasing number of active rigs in service and could increase sharply in the event of a shortage. Shortages of drilling and completion rigs, field equipment or qualified personnel could delay, restrict or curtail our exploration and development operations, which could in turn harm our operating results.

We are currently experiencing an extreme shortage of well casing, which is becoming an increasing world-wide issue in our industry. Such extreme and potentially prolonged shortages prevent us from completing planned drilling operations, which may have significant implications on our ability to meet fixed drilling commitments in some of our properties, especially in relation to our Buckskin Mesa properties. Our inability to secure critical supplies such as well casing can bring our entire drilling operation to a halt until supply shortages ease.

17

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

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Because total estimated proved reserves include our proved undeveloped reserves at September 30, 2007, production will decline even if those proved undeveloped reserves are developed and the wells produce as expected. The rate of decline will change if production from our existing wells declines in a different manner than we have estimated. The rate of decline may change under other circumstances as well. As a result, our future oil and natural gas reserves, and our production are highly dependent upon our success in efficiently developing and exploiting our current reserves. In addition, our potential oil and gas revenues and production depend on us finding or acquiring additional recoverable reserves economically. Our cash flow and results of operations are also dependent upon these factors. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs.

Assets may be impaired.

Under full cost accounting rules, capitalized costs of proved oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the “Ceiling Test” generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires an impairment charge for accounting purposes if the ceiling is exceeded. Impairments result in a charge to earnings, but do not impact cash flow from operating activities. Once incurred, an impairment of oil and gas properties is not reversible at a later date.

Our industry is heavily regulated which increases our cost of doing business and decreases our profitability.

U.S. and Australian federal, state and local authorities regulate the oil and gas industry. Legislation and regulations affecting the industry are under constant review for amendment or expansion, raising the possibility of changes that may affect, among other things, the pricing or marketing of oil and gas production. State and local authorities regulate various aspects of oil and gas drilling and production activities, including the drilling of wells (through permit and bonding requirements), the spacing of wells, the unitization or pooling of oil and gas properties, environmental matters, safety standards, the sharing of markets, production limitations, plugging and abandonment and restoration of wells. The overall regulatory burden on the industry increases the cost of doing business, which, in turn, decreases profitability.

Our operations must comply with complex environmental regulations that may have a material adverse effect on our business.

Our operations are subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities, including in the U.S. and in Australia. New laws or regulations, or changes to current requirements, could have a material adverse effect on our business. We will continue to be subject to uncertainty associated with new regulatory interpretations and inconsistent interpretations between state and federal agencies. We would face significant liabilities to the government or other third parties for discharges of oil, natural gas, produced water or other pollutants into the air, soil or water, and we would have to spend substantial amounts on investigations, litigation and remediation if such a spill were to occur. We cannot be sure that existing environmental laws or regulations, as currently interpreted or enforced, or as they may be interpreted, enforced or altered in the future, will not have a material adverse effect on our results of operations and financial condition.

18

Risks Related to Our Common Stock

Our stock price and trading volume may be volatile, which could result in losses for our stockholders.

The equity trading markets may experience periods of volatility, which could result in highly variable and unpredictable pricing of equity securities. The market price of our common stock could change in ways that may or may not be related to our business, our industry or our operating performance and financial condition. In addition, the trading volume in our common stock may fluctuate and cause significant price fluctuations. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common stock include:

- actual or anticipated quarterly variations in our operating results;
- changes in expectations as to our future financial performance or changes in financial estimates, if any, of public market analysts;
- announcements relating to our business or the business of our competitors;
- conditions generally affecting the oil and natural gas industry;
- the success of our operating strategy; and
- the operating and stock price performance of other comparable companies.

As a result of these factors, it is possible that the market price of our common stock will fluctuate or decline significantly in the future. In addition, many brokerage firms may not effect transactions and may not deal with low priced securities as it may not be economical for them to do so. This could have an adverse effect on developing and sustaining a market for our securities. In addition, an investor may be unable to use our securities as collateral.

Our common stock may not meet the criteria necessary to qualify for listing on one or more particular stock exchanges on which we seek or desire a listing. Even if our common stock does meet the criteria, it is possible that our common stock will not be accepted for listing on any of these exchanges.

Our common stock may be thinly traded, and therefore, an investor may not be able to easily liquidate his or her investment.

Although our common stock is currently traded on the OTC Bulletin Board, at any time, it may be thinly traded. To the extent that is true, an investor may not be able to liquidate his or her investment without a significant decrease in price, or at all.

Raising additional capital would dilute existing stockholders.

In order to pursue our business plans, we will need to continue to raise additional capital. If we obtain additional funding through the sale of common stock, the funding would dilute the equity ownership of existing stockholders.

We have not and do not anticipate paying dividends on our common stock.

We have not paid cash dividends to date with respect to our common stock. We do not anticipate paying dividends on our common stock in the foreseeable future since we will use all of our available cash to finance exploration and development of our properties. We are authorized to issue preferred stock and may pay dividends on our preferred stock issued in the future.

USE OF PROCEEDS

We will not receive any of the proceeds from the selling stockholders of shares of our common stock. However, we may receive the sale price of any common stock we sell to the selling stockholders upon exercise of the warrants. We expect to use the proceeds received from the exercise of warrants, if any, for general working capital purposes including the ongoing development and operations of the Company.

MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Market Information

Our common stock commenced trading on the OTC bulletin board on April 20, 2005, under the symbol "DGEO," and has been trading under the symbol "PHUN" since August 21, 2006. The following table sets forth the high and low bid prices per share of our common stock, as reported on the OTC bulletin board for the periods indicated. The following prices reflect inter-dealer prices, without retail mark-up, mark-down or commission, and may not represent actual transactions.

Quarter Ended:	High	Low
December 31, 2005	$1.79	$0.05
March 31, 2006	$3.36	$1.10
June 30, 2006	$4.23	$1.45
September 30, 2006	$2.98	$1.31
December 31, 2006	$2.30	$1.50
March 31, 2007	$1.85	$0.96
June 30, 2007	$1.29	$0.46
September 30, 2007	$0.55	$0.16
December 31, 2007	$0.36	$0.14
March 31, 2008	$0.25	$0.10

On June 27, 2008, the closing bid price for the common stock was $0.20.

Holders and Dividends

We have neither declared nor paid cash dividends on our capital stock and do not anticipate paying cash dividends in the foreseeable future. Our current policy is to retain cash to finance the exploration and development of our properties. Our Board of Directors will determine future declaration and payment of dividends, if any, in accordance with applicable corporate law.

As of June 27, 2008, there were 235 record holders of our common stock.

SELECTED FINANCIAL DATA

The following summary financial data is derived from the interim (unaudited) financial statements for the six months ended March 31, 2008 and 2007 and audited financial statements for the fiscal years ended September 30, 2007 and 2006 and the period from inception (June 20, 2005) through September 30, 2005.

We have prepared the financial statements in accordance with generally accepted accounting principles. You should read this summary financial data in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," "Business," and our financial statements.

STATEMENT OF OPERATIONS DATA

	Six Months Ended March 31, 2008	Six Months Ended March 31, 2007 (restated)	Year Ended September 30, 2007	Year Ended September 30, 2006	From Inception (June 20, 2005) to September 30, 2005	Cumulative from Inception (June 20, 2005) to March 31, 2008
	($ in thousands, except per share amounts)					
Total Revenues	$ 992	$ 1,338	$ 2,820	$ 36	$ --	$ 3,848
Total Operating Expenses	$ 6,371	$ 20,442	$ 45,981	$ 18,245	$ 2,096	$ 72,693
Loss from Operations	$ (5,379)	$ (19,104)	$ (43,161)	$ (18,209)	$ (2,096)	$ (68,845)
Total Other Expense	$ (10,374)	$ (2,217)	$ (6,650)	$ (2,483)	$ (23)	$ (19,530)
Net Loss	$ (15,753)	$ (21,321)	$ (49,811)	$ (20,692)	$ (2,119)	$ (88,375)
Net Loss per Common Share – Basic and Diluted	$ (0.05)	$ (0.10)	$ (0.20)	$ (0.14)	$ (0.02)	

BALANCE SHEET DATA

	March 31, 2008	September 30, 2007	September 30, 2006	September 30, 2005
	($ in thousands, except per share amounts)			
Working (Deficit) Capital	$ (39,773)	$ (37,865)	$ 1,275	$ 8,438
Oil and Gas Properties, Net	$ 173,975	$ 162,843	$ 45,973	7,231
Total Assets	$ 181,537	$ 182,024	$ 59,242	$ 8,500
Non-Current Liabilities	$ 34,601	$ 37,130	$ 522	$ --
Stockholders' Equity (Deficit)	$ 105,143	$ 100,324	$ 48,353	$ (1,196)

21

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 consolidated financial statements and notes appearing elsewhere in this prospectus.

Executive Summary

We are a development stage global oil and gas exploration and production company committed to acquiring and developing primarily unconventional natural gas and oil prospects that we believe have a very high probability of economic success. Since our inception in 2005, our principal business activities have been raising capital through the sale of common stock and convertible notes and acquiring oil and gas properties in the western United States and Australia. Currently, we own property in Colorado, where we have drilled five wells on our Buckskin Mesa property; Australia, where we have drilled one well on our property in the Northern Territory; and in Montana, where we hold a land position in the Bear Creek area. The wells on these properties have not yet commenced oil production. We also have working interests in eight additional wells in Colorado which are operated by EnCana Oil & Gas USA ("EnCana"). In November 2007, we sold 66,000 net acres of land and two wells in Montana and 177,445 net acres of land in Utah and on May 30, 2008, we sold 1,059 net acres of land and 16 wells in the Southern Piceance Basin in Colorado.

We are considered to be a development stage company as defined by Statement of Financial Accounting Standards ("SFAS") 7, Accounting and Reporting by Development Stage Enterprises, as we have not yet commenced our planned principal operations. A development stage enterprise is one in which planned principal operations have not commenced, or if its operations have commenced, there have been no significant revenue therefrom.

Results of Operations

Six Months Ended March 31, 2008 Compared to Six Months Ended March 31, 2007

Revenues. For the six months ended March 31, 2008, revenues declined $0.3 million to $1.0 million. The decrease in revenue was the result of natural production decline in the wells and to ownership interests in fewer producing wells, slightly offset by increases in commodity prices and a $0.2 million increase in other revenues, which represent revenues from certain services we are providing to Pearl Exploration and Production Ltd. Stemming from the sale of our Heavy Oil Projects effective October 1, 2007.

Lease Operating Expenses. Lease operating expenses declined $0.1 million during the six month period ended March 31, 2008 compared to the same period in the prior year. This decline is due to a decrease in activity year over year with respect to drilling and completions, where in the 2007 period, we were actively working on drilling and completions on certain of our Colorado properties and in the 2008 period, we were not.

General and Administrative. During the six months ended March 31, 2008, general and administrative expenses were $2.3 million or 29% lower than in the same period of 2007. The following table highlights the changes:

	Six months ended		
	2008	2007	Change
	($ in thousands)		
P Personnel and contract services	$ 2,138	$ 1,755	$ 383
L Legal	392	621	(229)
StStock-based compensation	1,602	3,617	(2,015)

TrTravel		73		779		(706)
OOther		1,485		1,230		255
Total	$	5,690	$	8,002	$	(2,312)

Overall, the decrease in general and administrative expense from the six months ended March 31, 2007 to the six months ended March 31, 2008, is primarily due to a $2.0 million decrease in stock-based compensation expense, a decrease in travel expense of $0.7 million, offset by an increase of $0.4 million in personnel and contract services expense.

Property Developmental Costs — Related Party. Property development costs of $1.8 million incurred during the six months ended March 31, 2007 relate to development costs we paid to MAB under the Development Agreement (described more fully in the Business section included later in this prospectus). We no longer pay project development costs to MAB as a result of the restructuring of our agreements with MAB effective January 1, 2007.

Impairment of Oil and Gas Properties. Costs capitalized for properties accounted for under the full cost method of accounting are subjected to a ceiling test limitation to the amount of costs included in the cost pool by geographic cost center. Costs of oil and gas properties may not exceed the ceiling, which is an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. During the six month period ended March 31, 2007, we recognized an impairment of $9.0 million, representing the excess of capitalized costs over the ceiling, as calculated in accordance with these full cost rules. There was no impairment charge in the six months ended March 31, 2008.

Depreciation, Depletion, Amortization and Accretion. During the six months ended March 31, 2008, depreciation, depletion, amortization and accretion declined $0.8 million. This decrease was driven by an adjustment in the previous year to proved reserves. During the fourth quarter of the prior year, our proved reserves were estimated by an independent reservoir engineer. We estimated that, had those reserves been obtained during previous quarters, depreciation, depletion and amortization would have increased by $1.0 million during the six month period ended March 31, 2007. The effect of this adjustment did not impact on our net loss for the year as the adjustment was ultimately reflected in impairment of oil and gas properties in the consolidated statements of operations.

Interest Expense. Interest expense increased $5.2 million during the six months ended March 31, 2008 compared to the same period in the previous fiscal year. This increase is attributable to two primary factors:

i. higher interest expense associated with warrants on the Series A 8.5% Convertible Debentures we issued in November 2007. Because these warrants are immediately exercisable, we recorded interest expense associated with the warrants of $3.2 million in the six month period ended March 31, 2008; and

ii. higher rates due to our default on certain of our borrowing agreements.

Trading Security Losses. In connection with the sale of certain of our properties to Pearl Exploration and Production Ltd ("Pearl"), we received a portion of the total purchase price in Pearl common stock. The value of these shares declined significantly from the date of the transaction until we sold the shares in March 2008. As a result, we recognized losses associated with these securities of $3.0 million during the six month period ended March 31, 2008. We did not have trading securities during the comparable period of the previous year.

Net Loss. Net loss for the six months ended March 31, 2008 was $15.8 million compared to a loss of $21.3 million during the last fiscal year. This $5.5 million change was primarily due to lower impairment, general and administrative and depreciation, depletion, amortization and accretion costs in the current year when compared with the same six months of the previous fiscal year, as described above. These factors were partially offset by higher interest expense.

Net loss per common share. For the six months ended March 31, 2008, net loss per common share was ($0.05) per share compared to a net loss of ($0.10) per share in the same period of the previous year. This change was driven by a lower net loss, as described above, and a higher share base primarily due to the issuance of common stock associated with certain of our debt agreements, amendments of certain agreements with MAB, and the issuance of Series A 8.5% convertible debentures.

23

Year Ended September 30, 2007 Compared to Year Ended September 30, 2006

Revenues. Our initial revenues were generated during 2006 in the amount of $35,656. The 2006 revenues were results of initial testing and production of four natural gas wells in the Piceance Basin of Colorado. Revenues increased to $2.8 million for the 2007 fiscal year. The increase is related to our earning revenue from our interest in 27 operating wells, operated by a third party, in the Piceance Basin of Colorado. In 2007, these 27 producing wells produced and sold approximately 457,000 Mcf of natural gas and 137 Bbls of oil. In 2006, we had four testing wells that sold 5,822 Mcf of natural gas. Average prices received for gas sold has increased to $6.16 per Mcf in 2007 from $6.12 per Mcf in 2006 as a result of market conditions.

Lease Operating Expenses. For 2007, lease operating expenses increased to $0.8 million compared to $3,672 in 2006. This is a result of the fact that we had only performed testing on the four wells that we earned revenue from in 2006 while those same wells were operating for the full year during 2007, plus there were an additional 23 wells operating during 2007.

General and Administrative. During 2007, general and administrative expenses increased by $4.4 million or 33% as compared to 2006. The following table highlights the areas with the most significant increases:

	Year Ended September 30,		
	2007	2006	Change
	($ in thousands)		
Payroll	$ 2,346	$ 846	$ 1,500
Consulting fees	2,887	1,292	1,595
Stock-based compensation expense	8,172	9,189	(1,017)
Legal	1,419	550	869
Travel	1,193	759	434
Investor relations	709	553	156
IT maintenance and support	205	13	192
Total	$ 16,931	$ 13,202	$ 3,729

The increase in general and administrative expenses in 2007 is a result of commencing operations and hiring full-time employees in June 2006.

Project Developmental Costs — Related Party. Property costs incurred to MAB were $1.8 million during 2007, as compared to $4.5 million in 2006, a decrease of $2.7 million or 60%. These costs decreased as a result of the restructure of our agreements with MAB, which was effective January 1, 2007.

Impairment of Oil and Gas Properties. Costs capitalized for properties accounted for under the full cost method of accounting are subjected to a ceiling test limitation as described previously. Should capitalized costs in the full cost pool exceed the limitations under the ceiling test, an impairment is recognized. During 2007, we recorded an impairment expense in the amount of $24.1 million, representing the excess of capitalized costs over the ceiling, as calculated in accordance with these full cost rules. The impairment in 2007 was primarily caused by an increase to the cost pool in the amount of $94.5 million, most of which was related to the fair value of the shares given up to MAB to increase our interest in several properties and as a result of the Consulting Agreement and amendments thereto (see the Business section of this prospectus for a more thorough description of the Consulting Agreement and other significant transactions with MAB). In accordance with accounting rules, the shares were valued at market price on the date of issuance, which was $1.62 per share.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, amortization and accretion expense ("DD&A") was $1.2 million in 2007 compared to $0.1 million in 2006. The increase is primarily a result of a higher amortization base in 2007.

Interest Expense. During 2007, interest expense was $6.7 million compared to $2.5 million during 2006. During 2007, interest expense included $3.4 million of costs paid to extend the Maralex Agreement (described more thoroughly in the Properties section of this prospectus) and $1.0 million of amortization of discount and deferred financing costs on the credit facilities entered into during that year. We expect that interest expense will increase for the fiscal year ending September 30, 2008 when compared to the fiscal year ended September 30, 2007 due to the borrowings under credit facilities we entered into in January and May 2007 and other borrowings that have or may occur.

Net Loss. During 2007, we incurred a net loss of $49.8 million compared to a net loss of $20.7 million during 2006.

Year Ended September 30, 2006 Compared to Year Ended September 30, 2005

Revenues. Our initial revenues were generated during 2006 in the amount of $35,656. The 2006 revenues were results of initial testing and production of four natural gas wells in the Piceance Basin of Colorado. During 2005, we had no operating wells and therefore had no revenues.

Lease Operating Expenses. During 2006, lease operating expenses were $3,672. During 2005, we had no operating wells and therefore incurred no lease operating expenses.

General and Administrative. During 2006, general and administrative expenses increased by $12.4 million compared to 2005. The following table highlights the areas with the most significant increases:

	Year Ended September 30,		
	2006	2005	Change
	($ in thousands)		
Payroll	$ 846	$ --	$ 846
Consulting fees	1,292	287	1,005
Stock-based compensation expense	9,189	822	8,367
Legal	550	29	521
Travel	759	15	744
Investor relations	553	--	553
Total	$ 13,189	$ 1,153	$ 12,036

Increases in all general and administrative costs from 2006 to 2005 were a result of commencing operations in 2006 and hiring employees in June 2006. Also during 2005, we had no employees or operations and our primary focus was to raise capital and acquire property.

Project Development Costs — Related Party. Property costs incurred to MAB were $4.5 million during 2006, as compared to $0.9 million in 2005. These costs increased as a result of the various EDAs entered into during 2006 that committed us to pay monthly project development costs to MAB. (See the Business section of this prospectus for a more thorough description of the MAB agreements and transactions.)

Depreciation, Depletion, Amortization and Accretion. DD&A expense was $0.1 million in 2006. We recorded no DD&A expense during 2005 because we had no oil and gas properties that were subject to amortization.

Interest Expense. During 2006, interest expense was $2.5 million, as compared to $23,029 during 2005. During 2006, interest expense included expense related to the issuance of convertible notes.

Net Loss. During 2006, we incurred a net loss of $20.7 million as compared to a net loss of $2.1 million during 2005.

Going Concern

The report of our independent registered public accounting firm on the financial statements for the year ended September 30, 2007, includes an explanatory paragraph relating to the uncertainty of our ability to continue as a going concern. We have incurred a cumulative net loss of $88.4 million for the period from inception (June 20, 2005) to March 31, 2008. Likewise, as of March 31, 2008, we had a working capital deficit of approximately $39.8 million, are in default on certain obligations, are not in compliance with the covenants of several loan agreements, and require significant additional funding to sustain our operations and satisfy our contractual obligations for our planned oil and gas exploration and development operations. We have had multiple property liens and foreclosure actions filed by vendors, some of whom have begun foreclosure proceedings, and have significant capital expenditure commitments. Our ability to establish ourselves as a going concern is dependent upon our ability to obtain additional funding in order to finance our planned operations.

Schedule of Contractual Commitments

The following table summarizes our obligations and commitments to make future payments under our notes payable, operating leases, employment contracts, consulting agreements and service contracts for the periods specified as of September 30, 2007:

	Payments Due by Period				
Contractual Obligations	Total	Less Than 1 Year	1-3 Years	3-5 Years	More than 5 Years
	($ in thousands)				
Related party notes	$ 12,805	$ 11,366	$ 1,439	$ --	$ --
Long-term borrowings	31,800	3,870	27,930	--	--
Office leases	1,039	205	634	200	--
Short-term borrowings	4,667	4,667	--	--	--
Drilling commitments	120,450	94,075	20,075	--	6,300
Seismic activity	2,000	2,000	--	--	--
Total	$ 172,761	$ 116,183	$ 50,078	$ 200	$ 6,300

Plan of Operation

Colorado. We expect that the development of our Colorado properties will include the following activities: (i) the tie-in of two wells drilled, cased and completed to date and the completion and tie-in of three wells drilled and cased to date in our Buckskin Mesa Prospect (four wells drilled and cased during fiscal year 2007; one well drilled and cased during the first quarter ended December 31, 2007; and two of the five drilled wells completed during the second quarter ended March 31, 2008); (ii) the drilling of a minimum of 13 commitment wells in our greater than 20,000 net acre Buckskin Mesa Prospect leasehold block surrounding the discovery wells for the Powell Park Field near Meeker, Colorado in the northern Piceance Basin; and (iii) the recompletion and tie-in of the six shut-in gas wells in the Powell Park Field acquired by us from a third party operator.

We anticipate that the following costs associated with the development of the Colorado assets will be incurred:

- $40.0 million to $50.0 million in connection with the Piceance II Project, to include expenditures for seismic data acquisition, lease and asset acquisition, drilling, completion, lease operation, and installation of production facilities subject to the Laramie transaction referenced below in “Business”.

- $41.0 million to $60.0 million in connection with the Buckskin Mesa Project, to include expenditures for seismic data acquisition, lease and asset acquisition, drilling, completion, lease operation, and installation of production facilities.

We are currently attempting to rationalize the Colorado asset base to raise capital and reduce our working interest and the associated development costs attributable to such retained interest.

Australia. We plan to explore and develop portions of our 7.0 million net acre position in the Beetaloo Basin project area located in northwestern Australia. During calendar year 2008, we plan to drill five wells in the exploration permit blocks. We anticipate that costs related to seismic acquisition, development of operational infrastructure, and the drilling and completion of wells over the next twelve months will range from $22.0 million to $30.0 million. As a means of reducing this exposure, selected portions of the project portfolio will be made available for farm-out to industry for cash and payment of expenses related to drilling and completion of one or more wells in each prospect.

Liquidity and Capital Resources

We have grown rapidly since our inception. At September 30, 2005, we had been operating for only a few months, had no employees, and had acquired an interest in two properties, West Rozel and Buckskin Mesa, aggregating approximately 12,400 net mineral acres. From 2006 to 2008, we added employees and acquired interests in additional properties. At March 2007, we had 16 full time employees and at March 2008 we grew to 15 full-time employees and 11 consultants. We had interests in properties aggregating approximately 21,700 net acres in Colorado and 7.0 million net acres in Australia at March 31, 2007 and grew to an aggregate of approximately 21,700 net acres in Colorado, 16,000 net acres in Montana, and 7.0 million net acres in Australia as of March 31, 2008.

Our initial plan for 2007 was to raise capital to fund the exploration and development of our acquired properties and we were successful at raising $35.5 million through borrowings, common stock issuances and subscriptions. We drilled (or participated in the drilling of) 39 gross wells, and completed (or participated in the completion of) 21 gross wells. During the third and fourth quarters of 2007, we revised our plan to (i) sell non-core assets to allow us to focus our exploration and development efforts in two primary areas: the Piceance Basin in Colorado and Australia, and (ii) to improve the economics of our projects by restructuring the Development Agreement with MAB. Accordingly, during the six months ended March 31, 2008, we sold our heavy oil assets and restructured the Development Agreement with MAB through amendments.

Working Capital. Our working capital is impacted by various business and financial factors, including, but not limited to: changes in the prices of oil and gas, the timing of operating cash receipts and disbursements, borrowings and repayments of debt, additions to oil and gas properties and increases and decreases in other non-current assets, along with other business factors that affect our net income and cash flows.

As of March 31, 2008, we had a working capital deficit of $39.8 million and cash of $1.6 million. As of September 30, 2007, we had a working capital deficit of $37.9 million and cash of $0.1 million. As of September 30, 2006, we had working capital of $1.3 million and cash of $10.6 million. The changes in working capital are primarily attributable to the factors described above. We expect that our future working capital will continue to be affected by these same factors.

In November 2007, we raised approximately $7.0 million through the sale of convertible debentures and $0.8 million through the pledge of our investment in Pearl shares. During the remainder of fiscal year 2008, we have sold working interests in some of our properties and we may complete additional private placements of debt or equity to raise cash to meet our working capital needs. A significant amount of capital is needed to fund our proposed drilling program for 2008. See “Plan of Operation” above.

Cash Flow. Net cash used in or provided by operating, investing and financing activities for the six months ended March 31, 2008 and 2007 and for the years ended September 30, 2007 and 2006 were as follows:

	Six months ended March 31, 2008	Six months ended March 31, 2007	Year ended September 30, 2007	Year ended September 30, 2006
	($ in thousands)			
Net cash used in operating activities	$ (6,420)	$ (6,712)	$ (10,326)	$ (10,546)
Net cash provided by (used in) investing activities	$ 4,753	$ (17,291)	$ (35,666)	$ (32,692)
Net cash provided by financing activities	$ 3,152	$ 15,073	$ 35,483	$ 52,620

Net Cash Used in Operating Activities. The changes in net cash used in operating activities are attributable to our net income adjusted for non-cash charges as presented in the consolidated statements of cash flows and changes in working capital as discussed above.

Net Cash Provided by (Used in) Investing Activities. Net cash provided by investing activities for the six months ended March 31, 2008 was primarily from cash received for the sale of oil and gas properties of $7.5 million and the sale of trading securities of $2.5 million offset by cash used for additions to oil and gas properties of $5.3 million. Net cash used in investing activities for the six months ended March 31, 2007 was primarily used for joint interest billings in the amount of $10.6 million, additions to oil and gas properties in the amount of $4.0 million and deposits on oil and gas property acquisitions of $2.2 million.

Net cash used in investing activities for the year ended September 30, 2007 was primarily used for: (1) additions to oil and gas properties of $33.0 million, and (2) a $2.0 million earnest money deposit related to the proposed purchase of the Powder River basin assets that became a note receivable. Net cash used in investing activities for the year ended September 30, 2006 was primarily used for additions to oil and gas properties.

Net Cash Provided by Financing Activities. Net cash provided by financing activities for the six months ended March 31, 2008 was primarily comprised of borrowings of $9.7 million, net of repayments of debt in the amount of $6.1 million, and payment of financing costs in the amount of $0.4 million. Net cash provided by financing activities for the six months ended March 31, 2007 was comprised of proceeds from promissory notes sold under a Credit and Security Agreement of $12.5 million and proceeds from the sale of units in our private placement shares for gross proceeds of $3.1 million. This was partially offset by payments on contracts payable of $0.5 million.

Net cash provided financing activities for the year ended September 30, 2007 was primarily comprised of borrowings of $32.3 million and the issuance of common stock subscriptions and common stock for $3.2 million. Net cash provided by financing activities for the year ended September 30, 2006 was comprised of the issuance of common stock and warrants of $36.4 million and the issuance of convertible notes of $17.8 million, offset by offering and financing costs of $1.6 million.

Capital Requirements. We currently anticipate our capital budget for the year ending September 30, 2008 to be approximately $42 million. Uses of cash for 2008 will be primarily for our drilling program in the Piceance Basin and in Australia. The following table summarizes our drilling commitments for fiscal year 2008:

Activity	Prospect	Aggregate Total Cost	Our Working Interest	Our Share (a)
		($ in thousands)		
Drill and complete eight wells	Buckskin Mesa	$ 24,000	100%	$ 24,000
Drill five wells	Beetaloo	20,000	100%	20,000(b)
Total		$ 44,000		$ 44,000

(a) We intend to sell portions of our working interest to third parties and farm-out additional portions for cash and the agreement of the assignee to pay a portion of our development costs.
(b) Our commitment in Australia is to have five wells drilled on the various permits by December 31, 2008.

Financing. During the six months ended March 31, 2008 and the fiscal year 2007, we entered into different short and long-term financing arrangements as follows:

(1) On November 13, 2007, we completed the sale of Series A 8.5% Convertible Debentures in the aggregate principal amount of $7.0 million. The debentures are due November 2012, are convertible at any time by the holders into shares of our common stock at a price of $0.15 per share and are collateralized by shares in our Australian subsidiary. Interest accrues at an annual rate of 8.5% and is payable in cash or in shares (at our option) quarterly, beginning January 1, 2008.

Debenture holders also received five-year warrants that allow them to purchase a total of 46.4 million shares of common stock at prices ranging from $0.24 to $0.27 per share. In connection with the placement of the debentures, we paid a placement fee of $0.3 million and issued placement agent warrants entitling the holders to purchase an aggregate of 0.2 million shares at $0.35 per share for a period of five years.

We originally agreed to file a registration statement with the SEC in order to register the resale of the shares issuable upon conversion of the debentures and the shares issuable upon exercise of the warrants. According to the Registration Rights Agreement, the registration statement was to be filed by March 4, 2008 and declared effective by July 2, 2008. The following penalties apply if filing deadlines and/or documentation requirements are not met in compliance with the stated rules: (i) we shall pay to each holder of Registrable Securities 1% of the purchase price paid in cash as partial liquidated damages; (ii) the maximum aggregate liquidated damages payable is 18% of the aggregate subscription amount paid by the holder; (iii) if we fail to pay liquidated damages in full within seven days of the date payable, we will pay interest of 18% per annum, accruing daily from the original due date; (iv) partial liquidated damages apply on a daily prorated basis for any portion of a month prior to the cure of an event; and (v) all fees and expenses associated with compliance to the agreement shall be incurred by us.

A waiver and amendment agreement relating to the above Registration Rights Agreement was signed by all investors on or before May 8, 2008. The agreement is an extension of filing date and effectiveness date to June 30, 2008 and December 31, 2008, respectively. Each purchaser waived i) our obligation to file a registration statement covering the Registrable Securities by March 4, 2008; ii) our obligation to have such registration statement declared effective by July 2, 2008, and iii) any penalties associated with the failure to satisfy such obligations as described above. In addition, each purchaser waived as events of default our failure to pay the January 1, 2008 and April 1, 2008 interest payments. As consideration for this waiver, we agreed to pay the interest installments due January 1, 2008 and April 1, 2008 by September 30, 2008, together with late fees of 18% per annum. In addition, warrants to purchase our common stock will be issued in an amount equal to 4% of the shares each purchaser received with the original agreement. The terms of these warrants mirror the terms given in the original agreement.

Provided that there is an effective registration statement covering the shares underlying the debentures and the volume-weighted-average price of our common stock over 20 consecutive trading days is at least 200% of the per share conversion price, with a minimum average trading volume of 0.3 million shares per day: (i) the debentures are convertible, at our option and (ii) are redeemable at our option at 120% of face value at any time after one year from date of issuance.

The debenture agreement contains anti-dilution protections for the investors to allow a downward adjustment to the conversion price of the debentures in the event that we sell or issue shares at a price less than the conversion price of the debentures.

Proceeds were used to fund working capital needs.

(2) On December 18, 2007, we obtained a loan from a third party in the amount of $0.8 million. The loan is secured by the shares that we received as partial consideration for the sale of our Heavy Oil assets, bears interest at 15% per annum and matures on January 18, 2008. Funds were used to fund working capital needs. This loan was paid in full in March 2008.

(3) During fiscal year 2007, we borrowed $0.5 million from Global. The note was unsecured and bore interest at 7.75% per annum. The funds were used primarily to fund working capital needs. We paid this note in full in November 2007.

(4) We entered into a note with MAB in the amount of $13.5 million as a result of the Consulting Agreement with MAB; however, no cash was actually received. During the six months ended March 31, 2008, the note was reduced by further amendments to the Consulting Agreement (the First, Second and Third Amendments) and as a result, we paid $0.3 million in cash towards repayment of this note. At March 31, 2008, the balance of this note was $1.3 million. The note is unsecured and bears interest at the London InterBank Offered Rate, ("LIBOR"). Although at March 31, 2008, we were in default on this note, MAB has waived and released us from defaults, failures to perform and any other failures to meet our obligations through October 1, 2008.

(5) We entered into six separate loans with the Bruner Family Trust, UTD March 28, 2005 for a total of $3.0 million. The long-term note bears interest at 8% and is due in full at the time when the January and May Credit Facilities have been paid in full (described below). A portion of one of these notes was assigned to a director of the company who then invested in our convertible debenture offering in November 2007. At March 31, 2008, the balance of these notes is $0.1 million. The short-term notes bear interest at LIBOR + 3% and are due 12 months from issue date.

(6) We entered into a $15.0 million credit facility in January 2007, with Global (the “January 2007 Credit Facility”). The January 2007 Credit Facility is secured by certain oil and gas properties and other assets of ours. It bears interest at prime plus 6.75% and is due to be paid in full in July 2009. We pay an advance fee of 2% on all amounts borrowed under the facility. We may prepay the balance without penalty. We are currently in default on interest

payments and not in compliance with the covenants. Global has waived all defaults that have occurred or that might occur in the future until October 2008, at which time all defaults must be cured. We have drawn the total $15.0 million available to us under this facility. The funds were used to fund working capital needs.

(7) We entered into a $60.0 million credit facility with Global in May 2007 (the "May 2007 Credit Facility"). The May 2007 Credit Facility is secured by the same certain oil and gas properties and other assets as the January 2007 Credit Facility. The May 2007 Credit Facility bears interest at prime plus 6.75% and is due to be paid in full in November 2009. We pay an advance fee of 2% on all amounts borrowed under the facility. We may prepay the balance without penalty. We are currently in default on interest payments and not in compliance with the covenants. Global has waived all defaults that have occurred or that might occur in the future until October 2008. At March 31, 2008 we had $42.2 million remaining available to us from the credit facility. The funds borrowed were used to fund our working capital needs.

Pursuant to (4) and (5) above Global received warrants to purchase an aggregate of 4.0 million shares of our common stock for the execution of the January 2007 Credit Facility, the May 2007 Credit Facility and the "most favored nation" letter to Global. In addition, an aggregate of 0.4 million warrants were issued for each $1.0 million advanced under each credit facility, resulting in a total of 17.1 million warrants issued related to advances on the credit facilities through March 31, 2008. The warrants are exercisable until second and third quarters of 2012. The exercise price of the warrants is equal to 120% of the weighted-average price of our common stock for the 30 days immediately prior to each warrant issuance date.

Prior to merger with GSL in May 2006, Digital entered into five separate loan agreements, aggregating $0.4 million, due one year from issuance, commencing October 11, 2006. The loans bear interest at 12% per annum, are unsecured, and are convertible, at the option of the lender, at any time during the term of the loan or upon maturity, at a price per share equal to the closing price of our common stock on the OTC Bulletin Board on the day preceding notice from the lender of its intent to convert the loan. As of January 10, 2007, we were in default on payment of the notes and we are currently in discussions with the holders to convert the notes and accrued interest into our common stock.

Other Cash Sources. On November 6, 2007, we sold our Heavy Oil assets. The cash proceeds of $7.5 million were used to fund working capital needs.

The continuation and future development of our business will require substantial additional capital expenditures. Meeting capital expenditure, operational and administrative needs for the period ending September 30, 2008 will depend on our success in farming out or selling portions of working interests in our properties for cash and/or funding of our share of development expenses, the availability of debt or equity financing, and the results of our activities. To limit capital expenditures, we may form industry alliances and exchange an appropriate portion of our interest for cash and/or a carried interest in our exploration projects using farm-out arrangements. We may need to raise additional funds to cover capital expenditures. These funds may come from cash flow, equity or debt financings, a credit facility, or sales of interests in our properties, although there is no assurance additional funding will be available or that it will be available on satisfactory terms. If we are unable to raise capital through the methods discussed above, our ability to execute our development plans will be greatly impaired. See the Going Concern section above.

Development Stage Company. We had not commenced principal operations or earned significant revenue as of March 31, 2008, and we are considered a development stage entity for financial reporting purposes. During the period from inception to March 31, 2008, we incurred a cumulative net loss of $88.4 million. We have raised approximately $102.4 million through borrowing and the sale of convertible notes and common stock from inception through March 31, 2008. In order to fund our planned exploration and development of oil and gas properties, we will require significant additional funding.

Off-Balance Sheet Arrangements

We do not have off-balance sheet arrangements.

Critical Accounting Policies and Estimates

We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our financial statements.

Oil and Gas Properties. We utilize the full cost method of accounting for oil and gas activities. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center on a by-country basis. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas properties is computed on the units-of-production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves.

Capitalized costs of oil and gas properties may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of estimated future net cash flows is computed by applying year end prices of oil and natural gas to estimated future production of proved oil and gas reserves as of year end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions.

Asset Retirement Obligation. Asset retirement obligations associated with tangible long-lived assets are accounted for in accordance with Statement of Financial Accounting Standards ("SFAS") No. 143, Accounting for Asset Retirement Obligations. The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a risk-adjusted rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method on a field-by-field basis. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense, and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion, amortization, and accretion expense in the accompanying consolidated statements of operations.

Share Based Compensation. Effective October 1, 2006, we adopted the provisions of SFAS No. 123(R) (As Amended), Share-Based Payment ("SFAS 123(R)"). SFAS No. 123(R) revises SFAS No. 123, Accounting for Stock-Based Compensation ("SFAS 123"), and supersedes Accounting Principles Board ("APB") Opinion 25, Accounting for Stock Issued to Employees and related interpretations ("APB 25"). SFAS 123(R) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods and services at fair value, focusing primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. It also addresses transactions in which an entity incurs liabilities in exchange for goods and services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. Prior to October 1, 2006, we accounted for stock-based compensation using the intrinsic value recognition and measurement principles detailed in APB 25. Stock-based compensation awarded to non-employees is accounted for under the provisions of EITF 96-18, Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services.

Under the fair value recognition provisions of SFAS 123(R), stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the service period, which generally represents the vesting period. The following table illustrates the pro-forma effect on net loss per share if compensation cost had been determined based upon the fair value at the grant dates in accordance with SFAS 123(R):

		Year Ended September 30,		
		2006		2005
		($ in thousands)		
Net loss as reported	$	(20,692)	$	(2,119)
Add stock-based compensation included in reported loss		9,189		823
Deduct stock-based compensation expense determined under fair value method		(9,189)		(1,202)
Pro-forma net loss	$	(20,692)	$	(2,498)
Net loss per share:				
As reported	$	(0.14)	$	(0.02)
Pro-forma	$	(0.14)	$	(0.02)

Impairment. SFAS No. 144, Accounting for the Impairment and Disposal of Long-Lived Assets ("SFAS 144"), requires long-lived assets to be held and used to be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We use the full cost method of accounting for our oil and gas properties. Properties accounted for using the full cost method of accounting are excluded from the impairment testing requirements under SFAS 144. Properties accounted for under the full cost method of accounting are subject to SEC Regulation S-X Rule 4-10, Financial Accounting and Reporting for Oil and Gas Producing Activities Pursuant to the Federal Securities Laws and the Energy Policy and Conversion Act of 1975 ("Rule 4-10"). Rule 4-10 requires that each regional cost center's (by country) capitalized costs, less accumulated amortization and related deferred income taxes not exceed a cost center "ceiling". The ceiling is defined as the sum of:

- the present value of estimated future net revenues computed by applying current prices of oil and gas reserves to estimated future production of proved oil and gas reserves as of the balance sheet date less estimated future expenditures to be incurred in developing and producing those proved reserves to be computed using a discount factor of 10%; plus
- the cost of properties not being amortized; plus
- the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less
- income tax effects related to differences between the book and tax basis of the properties.

If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess is charged to expense. During the period ended September 30, 2007, $24.1 million was charged to impairment expense. During the periods ended September 30, 2006 and 2005, there was no impairment charged to expense.

Recently Issued Accounting Pronouncements

In February 2007, the Financial Accounting Standards Board ("FASB"), issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities ("SFAS 159"), which allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value that are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. SFAS 159 also establishes presentation and disclosure requirements designed to draw comparison between entities that elect different measurement attributes for similar assets and liabilities. SFAS 159 will be effective for us on October 1, 2008. We have not assessed the impact of SFAS 159 on our consolidated results of operations, cash flows or financial position.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements ("SFAS 157"), which provides guidance for using fair value to measure assets and liabilities. The standard also responds to investors' requests for more information about: (1) the extent to which companies measure assets and liabilities at fair value; (2) the information used to measure fair value; and (3) the effect that fair value measurements have on earnings. SFAS 157 will apply whenever another standard requires (or permits) assets or liabilities to be measured at fair value. SFAS 157 does not expand the use of fair value to any new circumstances. SFAS 157 will be effective for us on

---

October 1, 2008. We have not assessed the impact of SFAS 157 on our consolidated results of operations, cash flows or financial position.

In July 2006, the FASB issued Interpretation ("FIN") No. 48, Accounting for Uncertainty in Income Taxes ("FIN 48"), which clarifies the accounting for uncertainty in income taxes recognized in financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 will be effective for us on October 1, 2007. We have not assessed the impact FIN 48 on our consolidated results of operations, cash flows or financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Because of our relatively low level of current oil and gas production, we are not exposed to a great degree of market risk relating to the pricing applicable to our oil and natural gas production. However, our ability to raise additional capital at attractive pricing, our future revenues from oil and gas operations, our future profitability and future rate of growth all depend substantially upon the market prices of oil and natural gas, which fluctuate considerably. We expect commodity price volatility to continue. We do not currently utilize hedging contracts to protect against commodity price risk. As our oil and gas production grows, we may manage our exposure to oil and natural gas price declines by entering into oil and natural gas price hedging arrangements to secure a price for a portion of our expected future oil and natural gas production.

Foreign Currency Exchange Rate Risk

We conduct business in Australia and are subject to exchange rate risk on cash flows related to sales, expenses, financing and investment transactions. We do not currently utilize hedging contracts to protect against exchange rate risk. As our foreign oil and gas production grows, we may utilize currency exchange contracts, commodity forwards, swaps or futures contracts to manage our exposure to foreign currency exchange rate risks.

Interest Rate Risk

Interest rates on future credit facility draws and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. This could limit our ability to raise funds in debt capital markets.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

On August 21, 2006, our Board of Directors approved 1) the termination of Telford Sadovnick, P.L.L.C. ("Telford") as our independent accountants and 2) the appointment of Hein & Associates LLP ("Hein") to serve as our independent accountants for the year ending September 30, 2006. The change was effective August 21, 2006.

Telford's reports on our financial statements for each of the years ended March 31, 2006 and 2005 did not contain, with the exception of a going concern disclaimer in each such report, an adverse opinion or disclaimer of opinion, nor were such reports qualified or modified as to uncertainty, audit scope, or accounting principles.

During the years ended March 31, 2006 and 2005, and the period ended August 21, 2006, there were no disagreements with Telford on any matter of accounting principle or practice, financial statement disclosure, or auditing scope or procedure which, if not resolved to Telford's satisfaction, would have caused them to make reference to the subject matter of the disagreement in connection with the audit reports on our financial statements for such years; and there were no events as set forth in Item 304(a)(1)(iv) of Regulation S-B.

We provided Telford with a copy of the foregoing disclosures. We filed as an exhibit to a report on Form 8-K a letter from Telford relating to the disclosure included in the Form 8-K.

During the years ended March 31, 2006 and 2005 and through August 21, 2006, we did not consult Hein with respect to the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our consolidated financial statements, or on any other matters or reportable events as set forth in Items 304(a)(2)(i) and (ii) of Regulation S-B. Hein was the independent accountants for our subsidiary, PetroHunter Operating Company from its inception (June 2005) until we acquired substantially all of its outstanding common stock (May 12, 2006).

On January 29, 2008, Hein informed the Audit Committee of our Board of Directors ("Audit Committee") that they were resigning as our independent registered public accounting firm. The decision to change accountants was approved by the Audit Committee on January 31, 2008. The reports of Hein on the consolidated financial statements for the two most recent fiscal years ended September 30, 2007 and 2006, did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope, or accounting principles, except that the audit reports for both years contained an explanatory paragraph regarding our ability to continue as a going concern.

The report of Hein to the Audit Committee and our management addressing management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting as of September 30, 2007 indicates that we did not maintain effective internal control over financial reporting as of September 30, 2007 due to the effect of the following material weaknesses:

1. We did not have an adequate process for monitoring accounting and financial reporting and had not conducted a comprehensive review of the account balances and transactions that had occurred during the year. However, we did conduct such a review prior to filing of the Form 10-K.

2. We did not have sufficient controls to ensure that the accounting department would receive or review material documents, or to ensure that the accounting department would receive or review material information on a timely basis.

In connection with the interim review of the June 30, 2007 financial statements, Hein advised us that we did not have effective internal control over financial reporting due to the effect of the following material weaknesses:

We did not have sufficient controls to ensure that our accounting department would receive or review material documents, or to ensure that the accounting department would receive or review material information on a timely basis. There was not an effective system in place to ensure that those responsible for financial reporting received copies of Board minutes which reflected the issuance of common shares of stock. In addition, our accounting department did not have adequate staffing to provide timely financial information

In connection with the audit of the September 30, 2006 financial statements, Hein advised us that we did not have effective internal control over financial reporting due to the effect of the following material weakness:

Our staffing for the period under audit and record keeping was not adequate to ensure an effective internal control structure as evidenced by the lack of recording certain equity transactions on a timely basis and delays in providing necessary information to the auditors.

In connection with the interim review of the June 30, 2006 financial statements, Hein advised us that we did not have effective internal control over financial reporting due to the effect of the following material weakness:

Our current staffing is not adequate to ensure an effective internal control structure as evidenced by the overpayment of certain development fees to a related party and the filing of the Form 10-QSB for the three and nine months periods ended June 30, 2006 prior to the completion of the review by our independent registered public accounting firm.

During the fiscal years ended September 30, 2007 and 2006 and through the subsequent interim period ending January 29, 2008, there were no disagreements with Hein on any matter of accounting principles or practices, financial statement disclosure or auditing scope or procedure, which disagreements, if not resolved to the satisfaction of Hein, would have caused Hein to make reference thereto in its report on our financial statements for such years. Further, except as described above, there were no other reportable events as described in Item 304(a)(1)(v) of Regulation S-K occurring within our two most recent fiscal years and the subsequent interim period ending January 29, 2008.

We provided Hein with a copy of the foregoing disclosures. We filed as an exhibit to a report on Form 8-K a letter from Hein relating to the disclosure included in the Form 8-K.

On January 31, 2008, the Audit Committee approved the engagement of Gordon, Hughes & Banks, LLP (“GHB”) to serve as our principal accountant to audit our financial statements for the fiscal year ending September 30, 2008 and to perform procedures related to the financial statements to be included in our quarterly reports on Form 10-Q, beginning with and including the quarter ending December 31, 2007. That decision was approved and ratified by our Board of Directors on January 31, 2008.

During our two most recent fiscal years ended September 30, 2007 and 2006, we consulted GHB on the application of the Financial Accounting Standards Board 109, Accounting for Income Taxes and accrued $2,425 in fees related to that consultation.

BUSINESS

Corporate Background

We are a development stage global oil and gas exploration and production company committed to acquiring and developing primarily unconventional natural gas and oil prospects that we believe have a very high probability of economic success. Since our inception in 2005, our principal business activities have been raising capital through the sale of common stock and convertible notes and acquiring oil and gas properties in the western United States and Australia. Currently, we own property in Colorado, where we have drilled five wells on our Buckskin Mesa property, and Australia, where we have drilled one well on our property in the Northern Territory and in Montana, where we hold a land position in the Bear Creek area. The wells on these properties have not yet commenced oil and gas production. We own working interests in eight additional wells in Colorado which are operated by EnCana Oil & Gas USA ("EnCana") and are currently producing gas. In November 2007, we sold 66,000 net acres of land and two wells in Montana and 177,445 net acres of land in Utah, and in May 2008, we sold 625 net acres of land and 16 wells in the Southern Piceance in Colorado, allowing us to focus on our Buckskin Mesa property and Australia.

Our predecessor, Digital Ecosystems Corp. ("Digital"), was incorporated on February 21, 2002 under the laws of the state of Nevada. On February 10, 2006, Digital entered into a share Exchange Agreement (the "Exchange Agreement") with GSL Energy Corporation ("GSL") and certain shareholders of GSL pursuant to which Digital acquired more than 85% of the issued and outstanding shares of common stock of GSL in exchange for shares of Digital's common stock. The Exchange Agreement was completed on May 12, 2006. At that time, GSL's business, which was formed in 2005 for the purpose of acquiring, exploring, developing and operating oil and gas properties, became Digital's business and GSL became a subsidiary of Digital. Since this transaction resulted in the former shareholders of GSL acquiring control of Digital, for financial reporting purposes, the business combination was accounted for as an additional capitalization of Digital (a reverse acquisition with GSL as the accounting acquirer). In accounting for this transaction:

i. GSL was deemed to be the purchaser and parent company for financial reporting purposes. Accordingly its net assets were included in the consolidated balance sheet at their historical book value; and
ii. control of the net assets and business of Digital was effective May 12, 2006 for no consideration.

Subsequent to the closing of the Exchange Agreement, Digital acquired all the remaining outstanding stock of GSL, and effective August 14, 2006, Digital changed its name to PetroHunter Energy Corporation ("PetroHunter"). Likewise, in October 2006, GSL changed its name to PetroHunter Operating Company.

PetroHunter is considered a development stage company as defined by Statement of Financial Accounting Standards ("SFAS") 7, Accounting and Reporting by Development Stage Enterprises, as we have not yet commenced our planned principal operations. A development stage enterprise is one in which planned principal operations have not commenced, or if its operations have commenced, there have been no significant revenue therefrom.

PaleoTechnology

Effective August 31, 2007, PetroHunter sold its interest in Paleo in consideration for a royalty interest in the net revenues derived from the sale of Paleo 'petro-environment' products or services, as defined in the Paleo business plan to include: petroleum related applications for enhanced recovery, reclaimed oils, residuum oil supercritical extraction, cleaning, unplugging, breaking oil-water emulsions, oil-sand separation, de-waxing and de-greasing, which Paleo (and/or its subsidiaries, affiliates and successors) develops over a fifteen-year period from August 31, 2007.

Southern Piceance Properties

On May 30, 2008, PetroHunter completed the sale of its working interest in its Southern Piceance properties in Garfield County, Colorado, to Laramie Energy II, LLC. The purchase price was $21 million before various adjustments for title defects, holdbacks and other matters in accordance with the purchase and sale agreement. The proceeds of the sale will be used to pay PetroHunter's creditors and for working capital.

The properties covered by the sale consist of approximately 625 net acres, including 16 wells which have been drilled, but not completed or connected to a pipeline. An additional 434 net acres may be included in the sale in a subsequent closing between the parties if PetroHunter and a third party lessor are able to enter into an amended lease. PetroHunter retains all of its interest in eight producing wells in Garfield County, which are operated by EnCana Oil & Gas (USA), Inc.

Heavy Oil Assets

Effective October 1, 2007, we, through our wholly-owned subsidiary, PetroHunter Heavy Oil Ltd., completed the sale of its heavy oil assets located in Montana and Utah to Pearl Exploration and Production Ltd. (“Pearl”), a company whose stock is traded on the TSX Venture Exchange. The assets sold included all of our working interest in certain oil and gas leases and related real and personal property interests comprised of heavy oil development projects we refer to as the Fiddler Creek and Promised Land prospects in Montana, and the West Rozel and Gunnison Wedge prospects in Utah. The closing took place on November 6, 2007.

The purchase price was a maximum of $30.0 million, payable as follows: (a) $7.5 million in cash at closing; (b) the issuance of 2.5 million common shares of Pearl equivalent to $10.0 million (based on a price of $4.00 Canadian per share as stipulated in the purchase and sale contract), excluding value attributable to leases on which title is being reviewed after closing, and value attributable to 4,645 net acres of leasehold which were not assigned at closing, pending Pearl’s attempt to renegotiate the terms of a purchase and development agreement with the third party that sold the acreage to PetroHunter; and (c) a performance payment (the “Pearl Performance Payment”) of $12.5 million in cash at such time as either: (i) production from the assets reaches 5,000 barrels per day; or (ii) proven reserves from the assets are greater than 50.0 million barrels of oil as certified by a third party reserve engineer. In the event that these targets have not been achieved by September 30, 2010, Pearl’s obligation to make the Pearl Performance Payment will expire.

The sale of assets to Pearl also resulted in amendments to existing agreements with third parties, including MAB’s relinquishment of all of its rights and obligations, including reassignment of certain reserved overriding royalty interests, in all PetroHunter properties in Utah and Montana, as set forth in the second amendment to the Acquisition and Development Agreement with MAB (the “Second Amendment”) (discussed below), and termination of PetroHunter’s obligation to pay an overriding royalty and a per barrel production payment to American Oil & Gas, Inc. (“American”) and Savannah Exploration, Inc. (“Savannah”), in consideration for: (a) five million common shares of PetroHunter common stock to be issued to American and Savannah; and (b) a contingent obligation to pay a total of $2.0 million to American and Savannah in the event that PetroHunter receives the Pearl Performance Payment.

MAB Resources LLC

We have entered into various agreements with MAB, a company that is controlled by our largest shareholders, Marc A. Bruner, who had an approximate 43% beneficial ownership interest in us at June 27, 2008. The following is a summary of those agreements.

The Development Agreement. From July 1, 2005 through December 31, 2006, we and MAB operated pursuant to a Development Agreement and a series of individual property agreements (collectively, the “EDAs”). The Development Agreement defined MAB’s and our long-term relationship regarding the ownership and operation of all jointly-owned properties and stipulated that we and MAB would sign a joint operating agreement governing all operations. The Development Agreement specified, among other things, that:

i. MAB and the Company each owned an undivided 50% working interest in all oil and gas leases, production facilities and related assets (collectively, the “Properties”).

ii.

We were named as Operator, and had appointed a related controlled entity, MAB Operating Company LLC, as sub-operator. We and MAB agreed to sign a joint operating agreement, governing all operations.

iii. Each party was to pay its proportionate share of costs and receive its proportionate share of revenues, subject to us bearing the following burdens:

a. Each assignment of Properties from MAB to us reserved an overriding royalty equivalent to 3% of 8/8ths (proportionately reduced to 1.5% of our undivided 50% working interest in the Properties) (the “MAB Override”), payable to MAB out of production and sales.

b. Each EDA provided that we would pay 100% of the cost of acquisitions and operations (“Project Costs”) up to a specified amount, after which time each party shall pay its proportionate 50% share of such costs. The maximum specified amount of Project Costs of which we were to pay 100%, under the Development Agreement for properties acquired in the future, was $100.0 million per project. There was no “before payout” or “after payout” in the traditional sense of a “carried interest” because our obligation to expend the specified amount of Project Costs and MAB’s receipt of its 50% share of revenues applied without regard to whether or not “payout” had occurred. Therefore, our payment of all Project Costs up to such specified amount may have occurred before actual payout, or may have occurred after actual payout, depending on each project and set of Properties.

c. Under the Development Agreement, we were to pay to MAB monthly project development costs representing a specified portion of MAB’s “carried” Project Costs. The total amount incurred to MAB by us was to be deducted from MAB’s portion of the Project Costs carried by the Company. During 2007, 2006 and 2005, we paid MAB $1.8 million, $4.5 million and $0.9 million, respectively, for Project costs which are classified on the consolidated statements of operations as Property development— related party in the affected periods.

The Consulting Agreement. Effective January 1, 2007, we and MAB began operating under an Acquisition and Consulting Agreement (the “Consulting Agreement”) which replaced in its entirety the Development Agreement described previously. The Consulting Agreement provides as follows:

i. MAB conveyed to us its entire remaining undivided 50% working interest in all rights and benefits under each EDA, and we assumed our share of all duties and obligations under each individual EDA (such as drilling and development obligations), with respect to said remaining undivided 50% working interest,

ii. A consulting agreement was agreed upon, including our obligation to pay fees in the amount of $25,000 per month for services rendered to us for which we paid a total of $0.2 million, during the year ended September 30, 2007,

iii. As a result of MAB’s conveyance of its remaining undivided 50% working interest to us, our working interest in certain oil and gas properties increased from 50% to 100%,

iv. Our obligation to pay up to $700.0 million in capital costs for MAB’s 50% interest as well as the monthly project cost advances against such capital costs was eliminated,

v. We became obligated for monthly payments in the amount of $0.2 million under a $13.5 million promissory note,

vi. MAB’s overriding royalty interest (the “Override”) was increased from 3% to 5%, half of which accrues but is deferred for three years. The Override does not apply to our Piceance II properties, and did not apply to certain other properties to the extent that the Override would cause our net revenue interest to be less than 75%,

vii. MAB would receive 7% of the issued and outstanding shares of any new subsidiary with assets comprised of the subject properties,

viii. MAB received 50.0 million shares of PetroHunter Energy Corporation common stock, and would receive up to an additional 50.0 million shares (the “Performance Shares”) if we met certain thresholds based on proven reserves.

We accounted for the acquisition component of the Consulting Agreement in accordance with the purchase accounting provisions of SFAS No. 141, Business Combinations. Accordingly, at the date of acquisition, we recorded oil and gas properties of $94.5 million, notes payable of $13.5 million, and common stock and additional paid-in-capital totaling $81.0 million (equal to the 50.0 million shares issued to MAB at the trading price of $1.62 per share for our common stock on the trading date immediately preceding the closing date of the transaction).

On October 29, 2007, November 15, 2007 and December 31, 2007 we entered into the first, second and third amendments, respectively, to the Consulting Agreement (the "First Amendment", the "Second Amendment" and the "Third Amendment", respectively, and collectively, "the Amendments"). Portions of the First Amendment were effective January 1, 2007, the Second Amendment was effective November 1, 2007 and the Third Amendment was effective December 31, 2007. The Amendments significantly changed several provisions of the Consulting Agreement.

Pursuant to the First Amendment: (a) MAB relinquished its overriding royalty interest in all properties in Montana and Utah effective October 1, 2007, (the Override still applies to our Australian properties and Buckskin Mesa property); (b) MAB received 25.0 million additional shares of our common stock; (c) MAB relinquished all rights to the Performance Shares; and (d) the parties' rights and obligations related to MAB's consulting services were terminated effective retroactively back to January 1, 2007.

Under the terms of the Second Amendment, effective November 1, 2007, the note payable to MAB was reduced in accordance with and in exchange for the following:

- By $8.0 million in exchange for 16.0 million shares of our common stock with a value of $3.7 million based on the closing price of $0.23 per share at November 15, 2007, and warrants to acquire 32.0 million shares of our common stock at $0.50 per share. The warrants expire on November 14, 2009;

- By $2.9 million in exchange for our release of MAB's obligation to pay the equivalent amount as guarantor of the performance of Galaxy Energy Corporation under the subordinated unsecured promissory note dated August 31, 2007 and;

- A reduction to the note payable to MAB of $0.5 million for cash payments to be made by us subsequent to September 30, 2007.

Further, in the Second Amendment, MAB waived all past due amounts and all claims against PetroHunter (including the due date for the balance of $0.3 million owed to MAB out of the above-described $0.5 million payment, which is now due on or before February 1, 2008).

The net effect of the reduction of debt and issuance of our common shares in the Second Amendment will result in a net benefit to us of $3.8 million and will be reflected as additional paid-in-capital during the first fiscal quarter ending December 31, 2007. Monthly payments on the revised promissory note in the amount of $2.0 million commence February 1, 2008, and will be paid in full in two years.

Under the terms of the Third Amendment, effective December 31, 2007, the note payable to MAB was reduced: (a) by $0.4 million for our release of MAB's obligation to pay the equivalent amount as guarantor of the performance of Galaxy Energy Corporation under the subordinated unsecured promissory note dated August 31, 2007; and (b) by $0.2 million for MAB assuming certain obligations of Paleo, which Paleo owed to us.

Acquisition of Powder River Basin Properties

On December 29, 2006, we entered into a purchase and sale agreement (the "Galaxy PSA") with Galaxy Energy Corporation ("Galaxy") and its wholly-owned subsidiary, Dolphin Energy Corporation ("Dolphin"). Pursuant to the Galaxy PSA, we agreed to purchase all of Galaxy's and Dolphin's oil and gas interests in the Powder River Basin of

Wyoming and Montana (the “Powder River Basin Assets”). The purchase price for Powder River Basin Assets was $45.0 million, with $20.0 million to be paid in cash and $25.0 million to be paid in shares of our common stock. Closing of the transaction was subject to approval by Galaxy’s secured noteholders, approval of all matters by our Board of Directors, including our obtaining outside financing on terms acceptable to our Board of Directors, and various other terms and conditions. Pursuant to successive monthly amendments to the Galaxy PSA, either party could terminate the agreement if closing had not occurred by August 31, 2007.

We became the contract operator of the Powder River Basin Assets beginning January 1, 2007. In January 2007, we paid a $2.0 million earnest money deposit to Galaxy, which was due under the terms of the agreement. In the event the closing did not occur for any reason other than a material breach by us, the deposit was to convert into a promissory note (the “Galaxy Note”), payable to us, as an unsecured subordinated debt of both Galaxy and Dolphin, which was to be payable only after repayment of Galaxy’s and Dolphin’s senior indebtedness.

On March 21, 2007, we entered into a partial assignment of contract and guarantee (the “Assignment”) with MAB. Pursuant to the Assignment, we assigned MAB our right to purchase an undivided 45% interest in oil and gas interests in the Powder River Basin Assets. As consideration for the Assignment, MAB assumed our obligation under the Galaxy PSA to pay Galaxy $25.0 million in PetroHunter common stock. MAB also agreed to indemnify us against costs relating to or arising out of the termination or breach of the Galaxy PSA by Galaxy or Dolphin, and MAB agreed to guarantee the payment of principal and interest due to us under the Galaxy Note in the event the Galaxy PSA did not close.

The Galaxy PSA expired by its terms on August 31, 2007. We obtained the Galaxy Note in the amount of $2.5 million, which consisted of the $2.0 million earnest deposit plus a portion of operating costs paid by us and which was due upon the later of (i) the date upon which all of Galaxy’s senior indebtedness has been paid in full and (ii) December 29, 2007. As discussed previously, MAB was guarantor of the Galaxy Note. The Galaxy Note was paid by MAB in November 2007 (by the terms of the Second and Third Amendments to the Consulting Agreement) by offsetting it against the MAB Note (see discussion under “MAB Resources LLC”, discussed previously).

Competition

We operate in the highly competitive oil and gas areas of acquisition and exploration, areas in which other competing companies have substantially larger financial resources, operations, staffs and facilities. Such companies may be able to pay more for prospective oil and gas properties or prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit.

Environmental Matters

Operations on properties in which we have an interest are subject to extensive federal, state and local environmental laws that regulate the discharge or disposal of materials or substances into the environment and otherwise are intended to protect the environment. Numerous governmental agencies issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial administrative, civil and criminal penalties, and in some cases, injunctive relief for failure to comply.

Some laws, rules and regulations relating to the protection of the environment may, in certain circumstances, impose “strict liability” for environmental contamination. These laws render a person or company liable for environmental and natural resource damages, cleanup costs and, in the case of oil spills in certain states, consequential damages without regard to negligence or fault. Other laws, rules and regulations may require the rate of oil and gas production to be below the economically optimal rate or may even prohibit exploration or production activities in environmentally sensitive areas. In addition, state laws often require some form of remedial action, such as closure of inactive pits and plugging of abandoned wells, to prevent pollution from former or suspended operations.

Legislation has been proposed in the past and continues to be evaluated in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as “hazardous wastes”. This reclassification would make these wastes subject to much more stringent storage, treatment, disposal and clean-up requirements, which could have a significant adverse impact on our operating costs. Initiatives to further regulate the disposal of oil and gas wastes are also proposed in certain states from time to time and may include initiatives at the county, municipal and local government levels. These various initiatives could have a similar adverse impact on our operating costs.

The regulatory burden of environmental laws and regulations increases our cost and risk of doing business and consequently affects our profitability. The federal Comprehensive Environmental Response, Compensation and

Liability Act, or CERCLA, also known as the "Superfund" law, imposes liability, without regard to fault, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the current or prior owner or operator of the disposal site or sites where the release occurred and companies that transported, disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for the federal or state governments to pursue such claims.

It is also not uncommon for neighboring landowners and other third parties to file claims for personal injury or property or natural resource damages allegedly caused by the hazardous substances released into the environment. Under CERCLA, certain oil and gas materials and products are, by definition, excluded from the term "hazardous substances". At least two federal courts have held that certain wastes associated with the production of crude oil may be classified as hazardous substances under CERCLA. Similarly, under the federal Resource, Conservation and Recovery Act, or RCRA, which governs the generation, treatment, storage and disposal of "solid wastes" and "hazardous wastes," certain oil and gas materials and wastes are exempt from the definition of "hazardous wastes". This exemption continues to be subject to judicial interpretation and increasingly stringent state interpretation. During the normal course of operations on properties in which we have an interest, exempt and non-exempt wastes, including hazardous wastes, that are subject to RCRA and comparable state statutes and implementing regulations are generated or have been generated in the past. The federal Environmental Protection Agency and various state agencies continue to promulgate regulations that limit the disposal and permitting options for certain hazardous and non-hazardous wastes.

We believe that the operator of the properties in which we have an interest is in substantial compliance with applicable laws, rules and regulations relating to the control of air emissions at all facilities on those properties. Although we maintain insurance against some, but not all, of the risks described above, including insuring the costs of clean-up operations, public liability and physical damage, there is no assurance that our insurance will be adequate to cover all such costs, that the insurance will continue to be available in the future or that the insurance will be available at premium levels that justify our purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and operations. Compliance with environmental requirements, including financial assurance requirements and the costs associated with the cleanup of any spill, could have a material adverse effect on our capital expenditures, earnings or competitive position. We do believe, however, that our operators are in substantial compliance with current applicable environmental laws and regulations. Nevertheless, changes in environmental laws have the potential to adversely affect our operations. At this time, we have no plans to make any material capital expenditures for environmental control facilities.

Employees

As of May 31, 2008, we employed a total of 14 persons, all of which were full-time. None of our employees is covered by a collective bargaining agreement. In addition, we utilized the services of 20 full and part-time consultants.

Facilities

Our principal offices are located at 1600 Stout Street, Suite 2000, Denver, Colorado. We entered into two leases for these offices that run through April 2011 and June 2013, respectively, with an option to renew the 2011 lease for one additional lease term of 36 months. The leases requires monthly rent of $0.3 million, adjusting annually as provided in the lease agreements.

Legal Proceedings

As of March 31, 2008, we were a party to various legal proceedings and liens, including the following:

1. 21 vendors had filed liens applicable to our properties

41

2. 9 lawsuits had been filed related to these liens

3. A lawsuit was filed by the lessor of certain properties in the Piceance Basic for breach of our lease contract.

All of these legal proceedings and liens were subsequently resolved in conjunction with the Laramie transaction, as described more fully previously. As of the date of this filing, we are a party to the following legal proceedings and liens:

1. 1 lien applicable to our property in Rio Blanco in the amount of $0.1 million. We are currently negotiating a settlement for this lien.

2. A lawsuit was filed in August 2007 by a law firm in Australia in the Supreme Court of Victoria for the balance of legal fees owed (0.2 million Australian dollars). Subsequent to filing our March 31, 2008 10-Q, we paid nearly all amounts due under this lawsuit and the issue has been substantially resolved.

3. A lawsuit was filed in December 2007 by a vendor in the Supreme Court of Queensland for the balance which the vendor claims is owed (2.4 million Australian dollars). We are disputing this claim on the basis that the vendor breached the contract.

We may, from time to time, be involved in various claims, lawsuits, disputes with third parties, actions involving allegations of discrimination, or breach of contract incidental to the operations of our business.

PROPERTIES

Piceance Basin, Colorado Properties

Buckskin Mesa Project. As of March 31, 2008, we had drilled, but did not complete, five wells. We are required to drill 16 wells during the calendar year ending December 31, 2008, three during the first quarter and four during each of the second and third calendar quarters of 2008 and five during the fourth calendar quarter of 2008, under the terms of an agreement between us and a third party assignor, Daniels Petroleum Company (“DPC”). If we do not satisfy these quarterly drilling requirements, our agreement with DPC requires that we pay DPC $0.5 million for each undrilled well on the last day of the applicable quarter. At the end of the first calendar quarter of 2008, we extended and subsequently exercised our right to pay $0.5 million in penalties for three wells that were required to be drilled that quarter by agreeing to pay the $1.5 million fee, plus a $1.0 million additional penalty. These amounts were paid on April 28, 2008, thereby bringing the total number of wells we are committed to drill for the remainder of calendar year 2008 to 13. We currently estimate our cost to drill and complete each well at $3.0 million, aggregating $39.0 million for the remaining 13 wells.

Piceance II Project. As disclosed previously, this property was sold to Laramie Energy II, LLC in May 2008. The following discussion applies to the period prior to the sale.

As of March 31, 2008, we had drilled, but did not complete, 16 wells in the Piceance Basin in Colorado.

On December 10, 2007, we entered into two agreements with EnCana Oil & Gas (USA) Inc. (“EnCana”) to exchange interests in certain Piceance Basin properties, which resulted in an increase in our working interest in 14 of the 16 wells mentioned above as follows:

Exchange 1 — We received from EnCana an interest in 40 net acres, including two wells, and conveyed to EnCana interests in 19 wells. We and EnCana relieved each other of existing obligations related to all past costs and operations of the respective properties exchanged. EnCana’s share of the costs to drill the two wells of $3.2 million reflected as

Joint interest billings in our consolidated balance sheet at September 30, 2007 was reclassified to Oil and gas properties during the first quarter ended December 31, 2007. In addition, our accounts receivable from EnCana for oil and gas sales and accounts payable to EnCana for lease operating expenses from the 19 wells, of $0.2

million and $0.1 million respectively, as of December 31, 2007, was also reclassified to Oil and gas properties during the first quarter ended December 31, 2007.

Exchange 2 — We received from EnCana an interest in 198 net acres, including 10 wells with a total present value of net cash flows discounted at 10% as of September 30, 2007 of $6.5 million. EnCana's share of the costs to drill the 10 wells of $9.4 million reflected as Joint interest billings in our consolidated balance sheet at September 30, 2007 was reclassified to Oil and gas properties during the first quarter ended December 31, 2007. In addition, we paid EnCana $1.0 million at closing that is also reflected in Oil and gas properties during the first quarter ended December 31, 2007.

By the terms of a Lease Acquisition and Development Agreement between MAB, Apollo Energy LLC and ATEC Energy Ventures and a third oil and gas lease pertaining to the Piceance II properties, we were required to drill 10 wells by December 31, 2008. Of the 10 wells, we drilled two during the fiscal year ended September 30, 2007 and we paid 100% of the costs to drill those two wells (two of the 16 wells mentioned above). Our joint interest partner's share in the amount of $1.0 million is reflected as Joint interest billings on our consolidated balance sheet at March 31, 2008. We have estimated total estimated costs to drill and complete these wells at approximately $16.8 million ($10.5 million to our 62.5% interest). We are currently conducting negotiations with the owners of the remaining 37.5% working interest owners to trade their interest in this lease for other oil and gas interests owned by us.

By the terms of a Lease Acquisition and Development Agreement between MAB, Apollo Energy LLC and ATEC Energy Ventures and of a certain oil and gas lease, we were to have commenced drilling on two wells by August 31, 2007 and an additional two wells by August 31, 2008. Subject to certain spacing orders being issued by the Colorado Oil and Gas Conservation Commission, that requirement has been deferred in its entirety by one year, thus requiring the drilling of two wells by August 31, 2008 and two wells by August 31, 2009. We have estimated total costs to drill and complete these wells at approximately $4.2 million ($1.6 million to our 37.5% interest in the dedicated spacing unit) to be incurred by August 31, 2008 and 2009, respectively.

By the terms of a Lease Acquisition and Development Agreement between MAB, Apollo Energy LLC and ATEC Energy Ventures and of a second oil and gas lease, pertaining to the Piceance II properties, we were to have commenced the drilling of four wells by June 30, 2007, an additional two wells by June 30, 2008 and an additional two wells by June 30, 2009. Subject to certain spacing orders being issued by the Colorado Oil and Gas Conservation Commission, that requirement has been deferred indefinitely. We have estimated total costs to drill and complete these wells at approximately $16.8 million ($8.4 million to our 50% interest).

Sugarloaf Project. On November 28, 2006, we entered into a purchase and sale agreement with Maralex Resources, Inc. and Adelante Oil & Gas, LLC (the "Maralex Agreement") (collectively "Maralex") for the acquisition and development of 2,000 net acres in the Jack's Pocket Prospect in Garfield County, Colorado, including a commitment to drill four wells in the prospect before the end of fiscal year 2008. An initial payment of $0.1 million was made upon execution of the Maralex Agreement. The remaining cash in the amount of $2.9 million and transfer of 2.4 million shares of our common stock was due on January 15, 2007. We amended the Maralex Agreement on several occasions, amending payment dates, issuing an additional 5.6 million shares of our common stock to Maralex and increasing the cash to be paid by $0.3 million. On June 29, 2007, Maralex notified us we were in default under the terms of the Maralex Agreement, as amended. Consequently, by the terms of the Maralex Agreement, we were required to pay Maralex an amount equal to 5% of the outstanding payable for each 20 days past due. As of September 30, 2007, we had reflected an accrued liability of $0.4 million with a corresponding amount in interest expense. If we failed to make payment of the remaining balance by August 28, 2007, Maralex, at its option, could return up to 80% of the previously issued shares of our common stock, and we would reassign to Maralex all leases acquired under the Maralex Agreement.

As of September 30, 2007, the balance due to Maralex is $1.8 million and is reflected as Contract payable — oil and gas properties in our year end consolidated balance sheet. On December 1, 2007, we paid Maralex $0.3 million related to payments on this agreement.

On December 4, 2007, Maralex terminated the Maralex Agreement and notified us that they would return 6.4 million shares of common stock and consequently, we were relieved of our drilling commitments. In addition, costs incurred in excess of the carrying value of the common stock to be returned, have been included in costs to be amortized, and have been included in the ceiling test at the lower of cost or estimated fair value.

Gibson Gulch Project. In August and November 2006, we entered into two agreements with a third party owner (the “Farmor”) to farm-in and participate in the drilling and completion of six wells located in the Mamm Creek Field, Garfield County, Colorado, due east of our Piceance II wells and assets. On February 27, 2007, we received a notice of default from the party designated as operator under the joint operating agreement (the “Operator”) covering the subject lands for failure to make timely payment of the amounts due for the completion of the four wells for which we had paid our share of drilling costs, and for drilling or completion of the remaining two wells. On March 29, 2007, the Farmor notified us that it was exercising its right to terminate our agreement and resume ownership of the working interests in the six wells drilled on the farmout acreage. The Farmor refunded all amounts paid by us to drill the wells less interest incurred on the past due joint interest billings, and credited us for the remaining balance due to the Operator.

Plan of Operations. We expect that the development of our Colorado properties will include the following activities: (i) the completion and tie-in of five wells drilled and cased to date in the Buckskin Mesa Prospect (four wells drilled and cased during fiscal year 2007 and one well drilled and cased during the first quarter ended December 31, 2007); (ii) the drilling, of a minimum of 13 commitment wells in our greater than 20,000 net acre Buckskin Mesa Prospect leasehold block surrounding the discovery wells for the Powell Park Field near Meeker, Colorado in the northern Piceance Basin; and (iii) the recompletion and tie-in of the six shut-in gas wells in the Powell Park Field acquired by us from a third party operator.

We anticipate that the following costs associated with the development of the Colorado assets will be incurred:

- $40.0 million to $50.0 million in connection with the Piceance II Project, to include expenditures for seismic data acquisition, lease and asset acquisition, drilling, completion, lease operation, and installation of production facilities

- $41.0 million to $60.0 million in connection with the Buckskin Mesa Project, to include expenditures for seismic data acquisition, lease and asset acquisition, drilling, completion, lease operation, and installation of production facilities

We are currently attempting to rationalize the Colorado asset base to raise capital and reduce our working interest and the associated development costs attributable to such retained interest.

Australia Properties

Beetaloo Project. The Beetaloo Basin property in the Northern Territory of Australia currently consists of approximately 7.0 million net contiguous acres. Sweetpea owns the existing four permits that cover this acreage. We have applied to the Department of Primary Industry, Fisheries and Mines for additional permits covering an additional 1.5 million net acres that is contiguous to our currently-owned permits.

Located about 600 kilometers south of Darwin, the Beetaloo Basin is a large basin, comparable in size to the Williston Basin in the U.S. or the entire southern North Sea basin. The basin has many thousands of meters of sediments, but the reservoirs of interest to us are within 4,000 meters of the surface, most less than 3,000 meters. The sedimentary rocks include thick (hundreds of meters), rich source rocks, namely the Velkerri Shale. There are also a number of sandstone reservoirs interbedded with the rich source rocks. These formations, from stratigraphically youngest to oldest, include the Cambrian Bukalara Sandstone, and the Neoproterozoic Jamison, Moroak, and Bessie Creek sandstones. A number of even deeper sandstones are expected to be very tight and were not prospective in the single well where they were tested east of the Basin.

Three primary plays have been recognized within the basin. The first is a conventional structural, shallow sweet oil play of 35° API gravity. The Bukalara, Jamison, and Moroak sands (and perhaps the Bessie Creek sand along the western margin) have potential for oil and gas accumulations in trapped and sealed geometries. Most of the eleven previous wells drilled within the basin had oil and gas shows, and the Jamison No. 1 well tested oil on a Drill Stem

Test. Detailed petrophysical analyses have been performed on all wells and have identified significant potential in some of these tests.

The second play is an unconventional fractured shale play within the Kyalla and Velkerri formations, not unlike the Barnett Shale play in Texas. It is unknown whether the hydrocarbons will be gas or oil (or possibly both) for this exploration target; however, the Barnett Shale model and algorithms in our petrophysical analyses of these shales suggest they are viable targets.

Finally, the Moroak and Bessie Creek sandstones offer a Basin Centered Gas Accumulation (BCGA) play at the center of the basin. It is an unconventional resource play characterized by a lack of a gas/water contact. Petrophysical analyses of several wells previously drilled in the basin demonstrate the presence of a BCGA in the basin.

We spudded the Sweetpea Shenandoah No. 1 well on July 31, 2007 and drilled to 4,724 feet. Intermediate casing was run on September 15, 2007 and the well was then suspended with an intention to deepen the well to a depth of 9,580 feet.

Because of its proximity and geological similarity to the Balmain No. 1 well, we regard this well as a twin to the Balmain No. 1 well that was drilled by an unrelated third party in 1992. Based on our initial drilling, geologically, the Shenandoah No. 1 well has matched its prognosis and the drilling results correlate with the Balmain No. 1 well.

To date, seven drilling locations have been identified based on extensive geological and geophysical analysis. These locations have been cleared through the Northern Land Council, responsible for consulting with and representing traditional landowners and other Aborigines with an interest in land. Final drilling approval was received in May 2007, and these locations have been staked and will be formally surveyed. The preparation of drilling pads and access lines commenced the last week of May 2007 and continued into June 2007. We are attempting to obtain drilling locations beyond the initial seven locations.

From July through November of 2006, 686 kilometers of new 2-D seismic data were acquired throughout the Beetaloo Basin. Additionally, 1,000 kilometers of previously acquired 2-D seismic data were reprocessed. Along, with the other existing 1,500 kilometers of 2-D seismic data that have not been reprocessed, geologic structure maps were generated for the basin.

The exploration drilling program for 2008 will test several play concepts within the basin. Hydrocarbon potential exists in shallow, conventional structures (in the form of oil), and in deeper unconventional reservoirs, including fractured shales and basin centered gas accumulations. The unconventional plays may be gas and/or oil. All of the exploration wells are planned to reach a total depth in the Bessie Creek Sandstone formation. The deepest penetration is expected to be 3,000 meters.

The exploration drilling program for 2008 will test several play concepts within the basin. Hydrocarbon potential exists in shallow, conventional structures (in the form of oil), and in deeper unconventional reservoirs, including fractured shales and basin centered gas accumulations. The unconventional plays may be gas and/or oil. All of the exploration wells are planned to reach a total depth in the Bessie Creek Sandstone formation. The deepest penetration is expected to be 3,000 meters.

Gippsland and Otway Project. On November 14, 2006, we and Lakes Oil N.L. ("Lakes Oil") entered into an agreement (the "Lakes Agreement") under which they would jointly develop Lakes Oil's onshore petroleum prospects (focusing on unconventional gas resources) in the Gippsland and Otway Basins in Victoria, Australia. The arrangement was subject to various conditions precedent, including completion of satisfactory due diligence, and the satisfactory processing and retention of certain lease applications.

The Lakes Agreement expired pursuant to its terms, and we and Lakes Oil are conducting discussions to formally terminate the Lakes Agreement wherein we would receive $0.1 million in escrowed funds and both parties will fully waive and release each other from all further obligations and liabilities.

Northwest Shelf Project. Effective February 19, 2007, the Commonwealth of Australia granted to Sweetpea an exploration permit in the shallow, offshore waters of Western Australia. The permit, WA-393-P, has a six year term and encompasses almost 20,000 acres. Geophysical data across the permit from public sources has been acquired and is being analyzed. We have committed to an exploration program with geological and geophysical data acquisition in the first two years with a third year drilling commitment and additional wells to be drilled in the subsequent three year period depending upon the results of the initial well.

Plan of Operations. We plan to explore and develop portions of our 7.0 million net acre position in the Beetaloo Basin project area located in northwestern Australia. During calendar year 2008, we plan to drill five wells in the exploration permit blocks. We anticipate that costs related to seismic acquisition, development of operational infrastructure, and the drilling and completion of wells over the next twelve months will range from $22.0 million to $30.0 million. As a means of reducing this exposure, selected portions of the project portfolio will be made available for farm-out to industry for cash and payment of expenses related to drilling and completion of one or more wells in each prospect.

Heavy Oil Properties

As described above, these properties were sold to Pearl effective October 1, 2007. The following discussion applies to the period prior to the sale to Pearl.

Great Salt Lake, Utah. We owned 173,738 net mineral acres under lease (covered by approximately 78 leases) on two principal properties, the West Rozel Field and the Gunnison Wedge prospect, each located in the Great Salt Lake of Utah. Permitting was required to be completed on this project during 2007. One well was required to be drilled prior to the expiration date of the primary term under each lease. We negotiated an extension to the dates of the work commitments under the acquisition agreement between us and American under an amendment executed on July 31, 2007.

Fiddler Creek, Montana. We owned 23,324 net acres situated on three anticlines located in the northern portion of the Big Horn Basin, which extends from north central Wyoming into southern Montana. Our interests encompassed shut-in wells and leasehold interests in the Roscoe Dome, Dean Dome and Fiddler Creek project areas. These anticlines are large asymmetric anticlines with proven production from several Cretaceous horizons; i.e. the Upper Greybull Sandstone, the Lower Greybull Sandstone and the Pryor Conglomerate.

Promised Land, Montana. We owned 48,793 net acres in a resource play evaluating heavy oil reservoirs in the Jurassic Swift Formation and the Lower Cretaceous Bow Island and Sunburst sandstone reservoirs in north central Montana. The Swift reservoirs were deposited in a shallow marine to estuarine depositional setting. The Swift sandstones are commonly oil saturated in the area, and most well tests report oil shows in the Swift. The reservoirs are up to 60 feet thick and composed of high quality sandstone, averaging about 20 percent porosity and permeabilities range up to one darcy. The oil gravities range from 10° to 22°API with viscosities of 1,500 centipoise to greater than 50,000 centipoise at 125°F.

Other Assets

Bear Creek, Montana. As of March 31, 2008, we owned 13,905 net acres of leasehold in a combination deeper conventional gas/coalbed methane project area located in southern Montana, east of the Fiddler Creek heavy oil assets. The primary deep objectives are incised Greybull valley-fill sequences along the Nye-Bowler lineament, and the Frontier sandstone, while the shallow Ft. Union provides an opportunity to produce methane from multiple thin coal lenses at intervals from 500 to 3,000 feet. No activity was conducted in this project area during the fiscal year, nor are any funds budgeted to evaluation of this asset in the coming year.

Production and Prices

The following table sets forth information regarding net production of oil and natural gas, and certain price and cost information for fiscal years ended September 30, 2007 and 2006. We did not have any production during the fiscal year ended September 30, 2005.

	For the Fiscal Year Ended September 30,	
	2007	2006
Production Data:		
Natural gas (Mcf)	456,740	5,822
Oil (Bbl)	137	—
Average Prices:		
Natural gas (per Mcf)	$ 6.16	$ 6.12
Oil (per Bbl)	$ 52.40	$ —
Production Costs:		