PYR ENERGY CORP
Form 10-Q
April 09, 2007

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U.S. Securities And Exchange Commission
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended February 28, 2007

OR

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

For the transition period from __________ to __________

Commission File No. 001-15511

PYR ENERGY CORPORATION

(Exact name of small business issuer as specified in its charter)

Maryland	95-4580642
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1675 Broadway, Suite 2450, Denver, CO	80202
(Address of principal executive offices)	(Zip Code)

(303) 825-3748

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large accelerated filer o Accelerated filer o Non-accelerated filer þ

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

Indicate the number of shares outstanding of each of the issuer s classes of common stock as of the latest practicable date.

Class	Outstanding as of April 6, 2007
Common stock, $0.001 par value	37,993,259

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ITEM 1. FINANCIAL STATEMENTS

PYR ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands, except per share data)

	February 28 2007 (Unaudited)	August 31, 2006
ASSETS		
CURRENT ASSETS		
Cash	$ 5,181	$ 6,254
Oil and gas receivables	1,692	1,846
Prepaid expenses and other current assets	147	64
Total current assets	7,020	8,164
PROPERTY AND EQUIPMENT		
Oil and gas properties under full cost, net	21,764	20,421
Furniture and equipment, net	52	45
	21,816	20,466
OTHER ASSETS		
Deferred financing costs and other assets	27	29
TOTAL ASSETS	$ 28,863	$ 28,659
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 158	$ 321
Amounts due oil and gas property owners	20	38
Accrued net profits interest payable		231
Other accrued liabilities	401	1,035
Asset retirement obligation	907	907
Total current liabilities	1,486	2,532
LONG TERM LIABILITIES		
Convertible notes	7,493	7,310
Asset retirement obligation	392	366
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock, $.001 par value; authorized 1,000,000 shares; issued and outstanding none		
Junior Participating Preferred Stock, Series A; $.001 par value; authorized 100,000 shares; issued and outstanding none		
Common stock, $.001 par value; authorized 75,000,000 shares; issued and outstanding 37,993,259 at 02/28/07 and 8/31/06, respectively	38	38
Capital in excess of par value	51,492	51,292

Accumulated deficit		(32,038)		(32,879)
Total stockholders equity		19,492		18,451
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$	28,863	$	28,659

The accompanying notes are an integral part of the consolidated financial statements.

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended February 28, 2007	Three Months Ended February 28, 2006	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006
	(in thousands, except share and per share data)			
REVENUES				
Oil and gas revenues	$ 2,369	$ 2,069	$ 4,988	$ 4,072
OPERATING EXPENSES				
Lease operating expenses	290	331	714	575
Production taxes, gathering and transportation	190	141	383	265
Net profits interest expense	(203)	320	(141)	580
Depletion, depreciation, amortization and accretion	906	509	1,803	866
General and administrative	686	584	1,312	1,087
Total operating expenses	1,869	1,885	4,071	3,373
INCOME FROM OPERATIONS	500	184	917	699
OTHER INCOME (EXPENSE)				
Interest income	44	68	100	115
Other income	12	5	14	5
Interest (expense)	(98)	(89)	(190)	(188)
Other (expense)		7		
Total other income (expense)	(42)	(9)	(76)	(68)
NET INCOME	$ 458	$ 175	$ 841	$ 631
NET INCOME PER COMMON SHARE BASIC AND DILUTED	$ 0.01	$ 0.00	$ 0.02	$ 0.02
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING-				
BASIC	37,993	37,915	37,993	36,658
DILUTED	38,224	38,623	38,219	37,353

The accompanying notes are an integral part of the consolidated financial statements.

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PYR ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended February 28, 2007	2006
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 841	$ 631
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	1,803	866
Amortization of financing costs	2	2
Interest expense converted into debt	184	175
Stock option expense for non-qualifying options issued		9
Non-cash stock compensation	200	
Gain on sale of other assets	(4)	
Changes in current assets and liabilities:		
Decrease in accounts receivable	154	107
Increase in prepaids and other current assets	(83)	(59)
(Decrease) increase in accounts payable	(38)	556
(Decrease) increase in amounts due oil and gas property owners	(18)	148
Decrease in net profits interest liability	(231)	(832)
(Decrease) increase in accrued expenses	(261)	207
Net cash provided by operating activities	2,549	1,810
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions of furniture and equipment	(20)	(21)
Additions to oil and gas properties	(4,419)	(6,138)
Proceeds from sale of properties and other assets	817	118
Net cash used in investing activities	(3,622)	(6,041)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from sale of common stock		8,157
Offering costs		(177)
Other		30
Net cash provided by financing activities		8,010
NET INCREASE (DECREASE) IN CASH	(1,073)	3,779
CASH, BEGINNING OF PERIODS	6,254	2,934
CASH, END OF PERIODS	$ 5,181	$ 6,713

The accompany notes are an integral part of the consolidated financial statements.

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PYR ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(continued)

SUPPLEMENTAL CASH FLOW INFORMATION:

	Six Months Ended February 28, 2007	2006
	(Unaudited)	
Cash paid for interest and income taxes	$ 5	$
Non-cash financing activities:		
Net increase in payables for capital expenditures		144
Debt issued for interest	184	175
Property sale proceeds received in third quarter		280
Asset retirement obligation increase	19	1

The accompanying notes are an integral part of the consolidated financial statements.

PYR ENERGY CORPORATION
Notes to Consolidated Financial Statements
February 28, 2007
(Unaudited)

1. **Organization**

PYR Energy Corporation (referred to as PYR, the Company, we, us and our) is an independent oil and gas expl and production company, engaged in the exploration, development and acquisition of crude oil and natural gas reserves and conducts its activities principally in the Rocky Mountain, Oklahoma, Texas and Gulf Coast regions of the United States. The Company was incorporated in March 1996 in the state of Delaware under the name Mar Ventures Inc. Effective as of August 6, 1997, the Company purchased all the ownership interests of PYR Energy, LLC, an oil and gas exploration company. On November 12, 1997, the name of the Company was changed to PYR Energy Corporation. Effective July 2, 2001, the Company was re-incorporated in Maryland through the merger of the Company into a wholly owned subsidiary, PYR Energy Corporation, a Maryland corporation. On February 18, 2004, PYR Cumberland LLC, PYR Mallard LLC, and PYR Pintail LLC were formed as wholly owned subsidiaries of PYR Energy Corporation. PYR Mallard LLC owns and is developing the Company s Mallard project in Uinta County, Wyoming. PYR Cumberland LLC and PYR Pintail LLC are currently inactive.

2. **Summary Of Significant Accounting Policies**

Basis of Presentation. The accompanying interim financial statements of PYR Energy Corporation are unaudited. In the opinion of management, the interim data includes all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the results for the interim period. The results of operations for the three and six months ended February 28, 2007 are not necessarily indicative of the operating results for the entire year. We have prepared the financial statements included herein pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosure normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to such rules and regulations. We believe the disclosures made are adequate to make the information not misleading and recommend that these condensed financial statements be read in conjunction with the audited financial statements and notes included in our Form 10-KSB for the year ended August 31, 2006.

Revenue Recognition and Gas Imbalances. The Company utilizes the sales method of accounting to record its revenues from the sales of gas and oil and production imbalances. Under this method, revenues are recognized based on the actual volume of gas and oil produced and sold to purchasers by the Company. Production imbalances exist on approximately 17 wells including the Nome-Long #1 well discussed in the following paragraph.

The operator of the Nome-Long #1 well, in which the Company has an 8.33% working interest, is requiring the Company to take its production in kind and to process its own gas. Currently, the Company does not have facilities in place to process its gas and is not able to take and sell its entitlement share of the production from the well, which the operator has been producing since late December 2006. Based on its entitlement share of the Nome-Long #1 well s production through February 28, 2007, the Company is under-produced by approximately 49 MMcf with a current value of approximately $397,000 for this well. In accordance with the sales method of accounting, the Company has not recognized its entitlement share of the production or revenues, or recorded a receivable in its financial statements for the production imbalance. At such time that the operator s share of remaining reserves are insufficient to settle the production imbalance, the Company would then be entitled to recoup the imbalance from the operator, and the Company would record a receivable due from the operator for the remaining reserve deficiency, valued at the product prices at that time. The Nome-Long #1 well production imbalance is expected to increase until the Company is able to process and sell its entitlement share of production from the well.

Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Our financial statements are based on a number of significant estimates, including collectibility of receivables, selection of the useful lives for property and equipment, timing and costs associated with its retirement obligations and oil and gas reserve quantities which are the basis for the calculation of depreciation, depletion and impairment of oil and gas properties.

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The oil and gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which the Company may be currently liable. In addition, our oil and gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. These prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves, which are considered significant estimates by us, and which are subject to changes. Price declines reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves) and may impact the impairment analysis of our full cost pool.

Earnings Per Share. Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during the applicable period. Diluted earnings per share incorporates the dilutive impact, if any, of outstanding stock options by including the effect of outstanding vested and unvested options and warrants in the average number of common shares outstanding during the period. The following table sets forth the computation of basic and diluted earnings per share (in thousands except per share data):

	Three Months Ended February 28,		Six Months Ended February 28,	
	2007	**2006**	**2007**	**2006**
Net income	$ 458	$ 175	$ 841	$ 631
Basic weighted-average common shares outstanding in period	37,993	37,915	37,993	36,658
Add dilutive effect of stock options and warrants	231	708	226	695
Diluted weighted-average common shares outstanding in period	38,224	38,623	38,219	37,353
Basic and diluted earnings per common share	$ 0.01	$ 0.00	$ 0.02	$ 0.02

Share Based Compensation. The Company has three share-based compensation plans, which are described in the Company s Form 10-KSB for the year ended August 31, 2006. Stock options are granted to employees and directors at exercise prices equal to the fair market value of the Company s stock at the dates of grants. Generally, options vest annually over various periods up to five years of continuous service and expire over various periods up to ten years from the date of grant. On occasion, the Company has issued warrants not covered under plans approved by the stockholders to individuals for services performed. As of February 28, 2007, the Company had 627,500 warrants outstanding with exercise prices ranging from $1.24 to $1.49 that expire over various periods up to October 17, 2010.

In October 1995, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 123, Accounting for Stock-Based Compensation (SFAS 123), effective for fiscal years beginning after December 15, 1995. This statement defines a fair value method of accounting for employee stock options and encouraged entities to adopt that method of accounting for its stock compensation plans. SFAS 123 allowed an entity to continue to measure compensation costs for these plans using the intrinsic value based method of accounting as prescribed in Accounting Pronouncement Bulletin Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). We elected to continue to account for our employee stock compensation plans as prescribed under APB 25. Under APB 25, no compensation expense was recorded for stock options issued under qualified plans. Had compensation cost for our stock-based compensation plans been determined based on the fair value at the grant dates for awards under those plans consistent with the method prescribed in SFAS 123, our net income and income per share for the three and six months ended February 28, 2006 would have been decreased to the pro forma amounts indicated below (in thousands, except per share data):

	Three Months	**Six Months**

	Ended February 28, 2006	Ended February 28, 2006
Net income as reported	$ 175	$ 631
Deduct total compensation cost determined under the fair value base method for all awards	(87)	(318)
Pro forma net income	$ 88	$ 313
Net pro forma income (loss) per share:		
As reported Basic and Dilutive	$ 0.00	$ 0.02
Pro forma Basic and Dilutive	$ 0.00	$ 0.01

In December 2004, the FASB issued its final standard on accounting for employee stock options, SFAS No. 123 (Revised 2004), Share-Based Payment (SFAS 123R). SFAS 123R replaces SFAS No. 123 and supersedes APB 25. SFAS 123R requires companies to measure compensation costs for all share-based payments, including grants of employee stock options, based on the fair value of the awards on the grant date and to recognize such expense over the period during which an employee is required to provide services in exchange for the award. Effective September 1, 2006, the Company adopted SFAS 123R using the modified prospective transition method. Under this transition method, compensation costs are recognized in the financial statements beginning with the effective date, based on the requirements of SFAS 123R for all share-based payments granted after that date, and based on the requirements of SFAS 123 for all unvested awards granted prior to the effective date of SFAS 123R. Prior periods have not been restated. Total share-based compensation expense for vested equity-based awards in the three and six months ended February 28, 2007, was approximately $142,000 and $200,000, or $0.00 and $0.005 per common share, respectively, and is reflected in General and Administrative expense in the Consolidated Statement of Operations. There was no impact on income tax expense. Total unrecognized compensation expense from unvested stock options, as of February 28, 2007, was approximately $200,000 which is expected to be recognized over a weighted average period of approximately one year.

The Company uses the Black-Scholes valuation model to determine the fair value of each option award. Expected volatilities are based on the historical volatility of the Company s stock over a period consistent with that of the expected terms of the options. The expected terms of the options are estimated based on factors such as vesting periods, contractual expiration dates, historical trends in stock price and historical exercise behavior. The risk-free rates for periods within the contractual life of the options are based on the yields of U.S. Treasury instruments with terms comparable to the estimated option terms. The following assumptions were used in estimating fair value of share-based awards for the six-month periods indicated:

	Six Months Ended February 28, 2007	**2006**
Expected life	5 years	5 years
Risk-free interest rate	4.7%	4.4%
Dividend yield	0.0%	0.0%
Expected volatility	85.2%	91.7%

The following table summarizes option activity during the six months ended February 28, 2007:

Options	Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at September 1, 2006	2,331,750	$ 1.07		
Options granted	164,014	0.99		
Options forfeited	(442,000)	1.06		
Outstanding at February 28, 2007	2,053,764	$ 1.06	3.1	$ 343,332
Exercisable at February 28, 2007	1,667,345	$ 1.05	2.9	$ 26,468

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The weighted-average grant-date fair value of options granted during the six months ended February 28, 2007 was $0.69. No options were exercised during the six months ended February 28, 2007. The fair value of options vested during the six months ended February 28, 2007 was approximately $125,000. Stock options outstanding and currently exercisable at February 28, 2007 are as follows:

		Options Outstanding			Options Exercisable			
Exercise Price Range	Number of Options Outstanding	Weighted Average Remaining Contractual Life (in years)		Weighted Average Exercise Price	Number of Options Exercisable		Weighted Average Exercise Price
$0.29 - $0.29	275,000	2.9	$	0.29	275,000	$	0.29
$0.30 - $1.00	556,014	3.4	$	0.89	426,262	$	0.89
$1.01 - $1.20	456,000	3.9	$	1.14	259,333	$	1.12
$1.21 - $1.82	766,750	2.4	$	1.44	706,750	$	1.42
	2,053,764	3.1	$	1.05	1,667,345	$	1.05

Recently Issued Accounting Pronouncements. In May 2005, the FASB, as part of an effort to conform to international accounting standards, issued SFAS No. 154, *Accounting Changes and Error Corrections* (SFAS No. 154), which was effective for us beginning on September 1, 2006. SFAS No. 154 requires that all voluntary changes in accounting principles be retrospectively applied to prior financial statements as if that principle had always been used, unless it is impracticable to do so. When it is impracticable to calculate the effects on all prior periods, SFAS No. 154 requires that the new principle be applied to the earliest period practicable. The adoption of SFAS No. 154 has not had a material effect on our financial position or results of operations.

On July 13, 2006, the FASB released Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109* (FIN 48). FIN 48 requires companies to evaluate and disclose material uncertain tax positions it has taken with various taxing jurisdictions. We are currently reviewing and evaluating the effect, if any, of adopting FIN 48 on our financial position and results of operations. We will be required to adopt FIN 48 for our fiscal year ended August 31, 2008.

In September 2006, the SEC issued Staff Accounting bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* SAB 108 provides guidance on the consideration of effects of the prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. The SEC Staff believes registrants must quantify errors using both a balance sheet and income statement approach and evaluate whether either approach results in quantifying a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. SAB 108 will be effective for the Company as of September 1, 2006; however, it is not expected to have a material affect on the Company s financial statements.

In September 2006, FASB issued SFAS No. 157, *Fair Value Measurements.* SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosure requirements regarding fair value measurement. Where applicable, this Statement simplifies and codifies fair value related guidance previously issued within GAAP. Although this Statement does not require any new fair value measurements, its application may, for some entities, change current practice. SFAS No. 157 will be effective for the Company beginning September 1, 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our financial statements.

3. **Debt**

On February 14, 2007, the Company entered into a bank credit facility (the Credit Facility) with the Bank of the West (the Bank). The initial borrowing base of the Credit Facility is $1 million, with a $30 million umbrella to the extent that the Bank approves amounts in excess of $1 million. Future borrowing bases will be computed based on proved natural gas and oil reserves. The Credit Facility matures on February 14, 2010 and bears interest, based on the borrowing base usage, at a variable rate equivalent to the Bank s prime rate or London Interbank Offered Rate (LIBOR) plus 2.5%, at the Company s election. The Company pays a commitment fee of 0.375% per annum of the unused borrowing base. This Credit Facility is secured by natural gas and oil properties representing at least 14% of the value of the Company s proved reserves. The Credit Facility contains financial covenants, including but not limited to a minimum current ratio, a maximum total debt to equity ratio and a minimum annual cash flow level. As of February 28, 2007, we had no borrowings outstanding under the Credit Facility and were in compliance with the Credit Facility s covenants.

4. **Stockholders Equity**

On January 29, 2007, the Company s Board of Directors received an offer letter (the Samson Original Offer) from Samson Investment Company (Samson) proposing to acquire 100% of the outstanding common stock of the Company at a cash price of $1.23 per share. On February 14, 2007, the Board of Directors engaged CK Cooper & Company as its financial advisor to assist the Board with the Samson Original Offer and other proposals that may come before the Board. On March 20, 2007, Samson filed a Schedule TO and announced its intent to commence a tender offer at $1.21 per share to acquire 100% of our outstanding common stock (the Samson Revised Offer). Management and the Board of Directors continue to work with CK Cooper and the Company s legal advisors to consider the Samson Revised Offer.

On January 31, 2007, the Company adopted a shareholder rights plan designed to ensure that all PYR Energy stockholders receive fair and equal treatment in the event of an unsolicited takeover proposal. The Board of Directors declared a dividend distribution of one Preferred Share Purchase Right on each outstanding share of common stock, par value $0.001 per share, held of record on February 9, 2007, payable to stockholders of record on that date. The Rights will automatically trade with the underlying common stock and will be exercisable only if, and upon the earlier to occur of, (a) ten business days after the public announcement that a person has acquired beneficial ownership of 15% or more of the Company s outstanding shares of common stock, and (b) the later to occur of (i) ten business days, or such later date as determined by the Board of Directors, following the commencement of, or the announcement of an intent to commence, a tender or exchange offer by a person for 15% or more of the outstanding shares of common stock, and (ii) ten business days or such later date, as determined by the Board of Directors, following the date the shareholder rights plan was entered into if the tender or exchange offer was commenced prior to that date.

In conjunction with the shareholder rights plan, 100,000 shares of $.001 par value preferred stock were designated as Series A Junior Participating Preferred Stock, none of which are outstanding. As of February 28, 2007, the Series A Junior Participating Preferred Stock was the Company s only designated preferred stock, the remainder of authorized preferred stock being undesignated.

Holders of all classes of stock are entitled to vote on matters submitted to stockholders, except that, when issued, each share of Series A Junior Participating Stock shall entitle the holder thereof to 1,000 votes on all matters submitted to a vote of the Company s stockholders.

There are no issued and outstanding shares of Series A Junior Participating Preferred Stock. The Series A Junior Participating Preferred Stock will be issued pursuant to our shareholder rights plan if a stockholder acquire shares in excess of the thresholds set forth in the plan. The Series A Junior Participating Preferred Stock ranks junior to all series of preferred stock with respect to dividends and specified liquidation events. Dividends on this series are cumulative and do not bear interest, however, no dividend payment, or payment-in-kind, may be made to holders of common stock without declaring a dividend on this series equal to 1,000 times the aggregate per share amount declared on common stock. Upon the occurrence of specified liquidation events, the holders of this series shall be entitled to receive an aggregate amount per share equal to 1,000 times the aggregate amount to be distributed per share to holders of shares of common stock plus an amount equal to any accrued and unpaid dividends. Upon consolidation, merger or combination in which shares of common stock are exchanged for or changed into other securities or other assets, each share of this series shall be similarly exchanged into an amount per share equal to 1,000 times that into which each share of common stock is exchanged. The number of Series A Junior Participating Preferred Stock will be proportionately changed in the event the Company declares or pays a common stock dividend or effects a stock split of common stock.

5. **Property Divestitures**

In February, the Company sold its interest in the Ryckman Creek project area, comprised of approximately 1900 net acres located in Uinta County, Wyoming, to a private company for $775,000. The Company received $34,000 for the sale of its interest in leases in the Blizzard prospect located in California.

6. **Contingencies**

On July 29, 2005, the Company filed a lawsuit in the U.S. District Court for the Eastern District of Texas, Beaumont Division against Samson Lone Star Limited Partnership (Samson) and Samson s parent company, Samson Resources Corp. The Company alleged in its complaint that Samson, the operator of a producing gas well in Jefferson County, Texas named the Sun Fee GU #1-ST well (the Sun Fee Well), had breached its obligations to the Company, which owns interests in the property on which the Sun Fee Well is located, by joining, without authorization, the Sun Fee Well into a unit (the Sidetrack Unit) with other properties in which the Company had no interest, many of which are non-productive. Samson has a large interest in the properties that Samson had joined into the unit. Pursuant to Samson s proposed pooling configuration, the Company s working and overriding royalty interests in the Sun Fee Well would be reduced substantially. The Company believes that Samson has no legal or contractual right to reduce the Company s interests in this manner. The Company is seeking monetary damages for all payments due and owing to the Company based on the proper, undiluted interests in the property.

Until approximately August 1, 2005, Samson had been paying the Company its share of oil and gas revenues based on Samson s calculation of the Company s net revenue interest (5.7%) in the Sun Fee Well after dilution for the disputed pooling of the non-productive properties, when it ceased paying the Company any portion of the production proceeds from the Sun Fee Well. On September 13, 2005, the Court entered a Preliminary Injunction ordering Samson to return the Company to pay status for the amounts upon which Samson had been paying the Company prior to the filing of the suit. On December 23, 2005, Samson filed a motion for summary judgment on the Company s claims, to which the Company filed its response on January 3, 2006, rigorously denying that Samson has grounds in law or fact for the requested relief. Further, on January 17, 2006, Samson filed a counterclaim for an unspecified overpayment to the Company, which was clarified by a subsequent filing on February 14, 2006, that it was disputing the unit interest originally attributed to the Company and now asserting that the Company s net revenue unit interest is approximately 4.7%. On March 28, 2006, the Court denied a motion by Samson to modify the present injunction to allow payment upon the lower amount. The Company has also filed additional claims against Samson for breach of contract or reformation of the certain assignment issued by Samson to the Company in April 2005 upon which Samson bases its present counterclaim. The outcome of the litigation will determine whether PYR s ownership in the Sun Fee Well consists of (a) the 5.7% net revenue interest (consisting of a 5.19% working and a 1.5% overriding royalty interest) that was formerly the portion that was not contested by Samson and represents the amount of the payments that Samson, as operator, has been paying PYR and that PYR has been recording in its financial statements; or (b) the 4.7% net revenue interest that Samson asserted in its February 14, 2006 filing; or (c) a net revenue interest higher than 5.7% as a result of the Company s prevailing on part or all of its claims that it owns an 8.33% working interest as well as an overriding royalty interest greater than 1.5%. On September 15, 2006, the U.S. District Court for the Eastern District of Texas issued its ruling on the outstanding motions for summary judgment that had been filed by both PYR and Samson. In its ruling, the Court held (1) that Samson did not have authority to pool PYR s 3.5% overriding royalty interest in the Sun Fee Well into the Sidetrack Unit and, therefore, that PYR is entitled to the full, undiluted interest in all production from the Sun Fee Well based on this overriding royalty; and (2) that although Samson controlled PYR s working interest at the time the Sidetrack Unit was formed, PYR would be able to maintain its claim for breach of contract against Samson for joining non-productive acreage into the unit. The Court also left for trial PYR s claims that Samson had also breached the underlying agreements by failing to assign to PYR its working interest in all properties as called for in the underlying contracts and by failing to give PYR geologic and other technical information applicable to the Sun Fee Well and the Sidetrack Unit. The Court held that PYR s alternate claim that Samson owed PYR a fiduciary duty in forming the Sidetrack Unit was fully resolved by its other rulings. The Court has set the case for trial beginning on or about July 16, 2007 and has requested the parties continue their efforts to mediate the claims unresolved by the Court s order.

On August 11, 2006, the State District Court for Jefferson County, Texas, 58th Judicial District, issued a final summary judgment in the Company s favor against Samson in Samson s suit to enjoin the Company s drilling of the Tindall Well, located in Jefferson County, Texas on property directly adjacent to and east of the Sun Fee Well. As previously reported, on the grounds that it had the exclusive right to serve as operator to drill the proposed Tindall Well, Samson had filed suit to enjoin or prevent the Company from drilling the planned well. Upon mutual agreement of the parties, no appeal will be taken from the final judgment.

On February 15, 2006, the Company filed a motion in the ongoing bankruptcy proceeding involving Venus Exploration Company (Venus) in the U.S. Bankruptcy Court for the Eastern District of Texas requesting that the Bankruptcy Court uphold its Order of April 9, 2004 approving the Company s purchase of Venus remaining assets free and clear of any obligations under a pre-bankruptcy Operating Agreement between Venus and Trail Mountain Inc. (Trail Mountain) that required Venus and Trail Mountain to offer each other participation in subsequently acquired oil and gas properties. The Company believes and has asserted in its motion that the pre-bankruptcy Operating Agreement was not listed among the contracts that were assigned to it under the sale in and under the approval of the Bankruptcy Court. Trail Mountain has filed an adversary proceeding against the Company requesting that the Bankruptcy Court find that the pre-bankruptcy Operating Agreement was still effective and that the Company is obligated to offer an opportunity to Trail Mountain to share in the lease upon which the proposed Tindall well is to be drilled. If Trail Mountain is successful, it will lead to a potential 50% reduction in the Company s interest in the lease, but could also lead to a corresponding assignment of interests in properties acquired by Trail Mountain, including certain properties assigned to the Sidetrack Unit. A ruling by the Court should also clarify whether the parties rights to operate their interests in the Cotton Creek Prospect are subject to an existing operating agreement or are free to enter into a new operating agreement. The parties have submitted the matter to the Bankruptcy Court on motions for summary and partial summary judgment.

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The Company will continue to vigorously pursue and defend its rights with respect to the foregoing matters.

On April 2, 2007, Lawrence Paskowitz filed a Class Action complaint with the District Court, City and County of Denver, Colorado against PYR Energy Corporation and its directors, David B. Kilpatrick, Bryce W. Rhodes, and Dennis M. Swenson, case number 2007 CV 3276. The complaint alleges that the Company s directors breached their duties of loyalty and care owed to PYR s stockholders because, according to the Plaintiff, the Company and its directors have sought to obstruct an offer made by Samson Investment Co. (Samson) to acquire the Company and pursued their own financial interest to the detriment of the Company s shareholders.

The Plaintiff contends that (i) PYR s issuance of 59,000 stock options at $1.01 per share to three PYR officers purposely caused an immediate dilution of Samson s ownership; (ii) PYR s adoption of a shareholders rights plan was a means of preventing any entity from acquiring control of PYR; (iii) the sale of PYR s assets known as the Ryckman Creek Field on February 2, 2007 were sold for a price substantially lower than the price Samson would have paid for it; and (iv) the directors have caused significant delay and engaged in corporate machinations designed to frustrate Samson s offer while failing to investigate and pursue potential alternative proposals.

In the complaint, Mr. Paskowitz has demanded the following: (i) judgment for declaring the instant action to be a proper class action; (ii) judgment ordering PYR to carry out their fiduciary duties to Mr. Paskowitz and the common stockholders and requiring PYR to respond in good faith to any bona fide potential buyer of PYR; (iii) judgment ordering PYR s Shareholder Rights Plan be temporarily and permanently enjoined; and (vi) judgment awarding the costs and disbursements of the action, including a reasonable allowance for Mr. Paskowitz s attorney s and experts fees.

The Company strongly disagrees with the claims set forth in the Class Action and intends to file an answer and vigorously pursue and defend its rights with respect to the foregoing.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for natural gas and oil, economic and competitive conditions, regulatory changes, estimates of proved reserves, potential failure to achieve production from development projects, capital expenditures and other uncertainties, as well as those factors discussed below and in our Annual Report on Form 10-KSB for the year ended August 31, 2006. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

The following discussion should be read in conjunction with the Financial Statements and Notes thereto referred to in Item 1. Financial Statements of this Form 10-Q.

Overview

PYR Energy Corporation (referred to as PYR, the Company, we, us and our) is an independent oil and gas expl and production company, engaged in the exploration, development and acquisition of crude oil and natural gas reserves. Our current focus is on the Rocky Mountain, Oklahoma, Texas and Gulf Coast regions.

Recent Developments

On January 29, 2007, the Company s Board of Directors received a tender offer letter (the Samson Original Offer) from Samson Investment Company (Samson) proposing to acquire 100% of the outstanding common stock of the Company at a cash price of $1.23 per share. On February 14, 2007, the Board of Directors engaged CK Cooper & Company as its financial advisor to assist the Board with the Samson Original Offer and other proposals that may come before the Board. On March 20, 2007, Samson filed a Schedule TO and announced its intent to instigate a tender offer at $1.21 per share to acquire 100% of our outstanding common stock (the Samson Revised Offer). Management and the Board of Directors continue to work with CK Cooper and the Company s legal advisors to consider the Samson Revised Offer.

Liquidity and Capital Resources

Our primary sources of liquidity historically have been from sale of our common stock, issuance of convertible notes, and to a much lesser extent, net cash provided by operating activities. Our primary use of capital has been for the acquisition, development, and exploration of oil and natural gas properties. As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations, planned capital expenditure activities and liquidity. Our future success in growing proved reserves and production is highly dependent on capital resources available to us and our success in finding or acquiring additional reserves. At February 28, 2007, we had approximately $5.5 million in working capital and cash of approximately $5.2 million.

<u>Cash Flow from Operating Activities</u>

Net cash provided by operating activities was $2.5 million and $1.8 million for the six months ended February 28, 2007 and 2006, respectively. The increase in net cash provided by operating activities was substantially due to the increase in production revenue. See Results of Operations for discussion of changes in revenues and expenses. Non-cash charges increased principally due to higher depreciation, depletion and amortization associated with increased production and higher depletion rates. Changes in current assets and liabilities decreased cash flow from operations by $477,000 in the six months ended February 28, 2007 compared with an increase in cash flows from operations of $127,000 in the same period in 2006. The decrease in current assets and liabilities for the current period is principally attributed to decreases in accounts payable and accrued expenses related to our drilling activity and a decrease in the net profits liability resulting from a net profits payment of $89,000 and the decrease in the net profits liabilities principally attributed to the excess of capital expenditures incurred over net profits realized from the properties during the period.

Operating cash flows are impacted by many variables, the most significant of which are production levels and the volatility of prices for natural gas and oil produced. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence production levels and market conditions for these products. These factors are beyond our control and are difficult to predict.

Capital Expenditures

Our capital expenditures approximated $4.4 million and $6.2 million for the first six months ended February 28, 2007 and 2006, respectively. The total for the current period includes principally $3.2 million for drilling, development, exploration and exploitation and $1.2 million for leasehold costs including litigation costs incurred related to our Nome project. Drilling costs for the current period were incurred principally on three wells located in Texas, the Nome-Long #1 well, the Nome-Harder #1 and the Wall #1 well, on the Harstad #1-15H well located in North Dakota and on the #1-30 Duck Federal well located in Wyoming.

During the six months ended February 28, 2007, we received $775,000 from the sale of our interests in the Ryckman Creek prospect and approximately $34,000 from the sale of our interests in our Blizzard prospect leases in California.

We anticipate our capital budget for the year ended August 31, 2007 will be approximately $10.0 million of which $4.4 million has been incurred through the first six months of fiscal 2007 and will be used for a diverse portfolio of development and exploration wells in our core areas of operation. In addition to the capital budget in fiscal 2007, the Company expects to pay its share of plugging costs of approximately $900,000 for six wells located in the East Lost Hills area of California. In accordance with FASB 143, *Accounting for Asset Retirement Obligations*, discussed in the Company s Form 10-KSB for the year ended August 31, 2006, the Company has previously recognized this plugging obligation as an asset retirement obligation, a current liability, on its balance sheet.

Financing Activities

On February 14, 2007, the Company entered into a bank credit facility (the Credit Facility) with the Bank of the West (the Bank). The initial borrowing base of the Credit Facility is $1 million, with a $30 million umbrella to the extent that the Bank approves amounts in excess of $1 million. Future borrowing bases will be computed based on proved natural gas and oil reserves. The Credit Facility matures on February 14, 2010 and bears interest, based on the borrowing base usage, at a variable rate equivalent to the Bank s prime rate or London Interbank Offered Rate (LIBOR) plus 2.5%, at the Company s election. The Company pays a commitment fee of 0.375% per annum of the unused borrowing base. This Credit Facility is secured by natural gas and oil properties representing at least 14% of the value of the Company s proved reserves. As of February 28, 2007, borrowings outstanding under the Credit Facility were nil and we have complied with all financial covenants of the Credit Facility during the period.

In mid-October 2005, we completed a private placement in which we sold 6,327,250 shares of common stock at a price of $1.30 per share, to a group of accredited institutional and individual investors. Net proceeds from this placement of approximately $8.0 million are to be used for general corporate purposes and costs associated with our development drilling portfolio located principally in the Rocky Mountains and Texas.

It is anticipated that the continuation and future development of our business will require additional, and possibly substantial, capital expenditures. We have no reliable source for additional funds for administration and operations to the extent our existing funds have been utilized. In addition, our capital expenditure budget for the fiscal year ending August 31, 2007 will depend on our success in selling additional prospects for cash, the level of industry participation in our exploration projects, the availability of debt or equity financing, cash on hand and the results of our activities. We anticipate spending a minimum of approximately $10.0 million, of which $4.4 million has been spent through the first six months of fiscal 2007, on exploration and development activities during our fiscal year ending August 31, 2007. To limit capital expenditures, we intend to form industry alliances and exchange an appropriate portion of our interest for cash and/or a carried interest in our exploration projects. 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.

Our future financial results continue to depend primarily on (1) our ability to discover commercial quantities of hydrocarbons; (2) the market price for oil and gas; (3) our ability to continue to source and screen potential projects; and (4) our ability to fully implement our exploration and development program with respect to these and other matters. There can be no assurance that we will be successful in any of these respects or that the prices of oil and gas prevailing at the time of production will be at a level allowing for profitable production.

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Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements, which are not in the normal course of the industry including the Company s net profits interest and gas balancing arrangements, as of February 28, 2007. Pursuant to the net profits agreement with the Venus Exploration Trust (the Trust), the Company is obligated to pay the Trust when revenues exceed expenditures with respect to the specific projects subject to the net profits agreement. As of February 28, 2007, expenditures exceed revenues from the projects subject to the net profits agreement and accordingly, the Company has not recognized a liability. At some time in the future, when revenues exceed expenditures, the Company will be obligated to pay the Trust.

The Company utilizes the sales method of accounting to record its revenues from the sales of gas and oil and production imbalances. Under this method, revenues are recognized based on the actual volume of gas and oil produced and sold to purchasers. Production imbalances exist on approximately 17 wells including the Nome-Long #1 well discussed in the following paragraph.

The operator of the Nome-Long #1 well, in which the Company has an 8.33% working interest, is requiring the Company to take its production in kind and to process its own gas. Currently, the Company does not have facilities in place to process its gas and is not able to take and sell its entitlement share of the production from the well, which the operator has been producing since late December 2006. Based on its entitlement share of the Nome-Long #1 well s production through February 28, 2007, the Company is under-produced by approximately 49 MMcf with a current value of approximately $397,000 for this well. In accordance with the sales method of accounting, the Company has not recognized its entitlement share of the production or revenues, or recorded a receivable in its financial statements for the production imbalance. At such time that the operator s share of remaining reserves are insufficient to settle the production imbalance, the Company would then be entitled to recoup the imbalance from the operator, and the Company would record a receivable due from the operator for the remaining reserve deficiency, valued at the product prices at that time. The Nome-Long #1 well production imbalance is expected to increase until the Company is able to process and sell its entitlement share of production from the well.

Summary of Development and Exploration Projects

Our development, exploration, and acquisition activities are focused primarily in select areas of the Rocky Mountains, Oklahoma, Texas and the Gulf Coast. A number of these projects offer multiple drilling opportunities with individual wells having the potential of encountering multiple reservoirs.

The following is an update of our production and exploration areas and significant projects. While actively pursuing specific production and exploration activities in each of the following areas, we continually review additional acquisition opportunities in our core areas that meet our production and exploration criteria. Currently, PYR s net production is approximately 5.0 MMcfe per day, which includes new production from the Nome-Long #1, the Wall GU#1, and the Harstad #1-15H.

Rocky Mountain Region

Mallard Project. The Company s Mallard Project is located within the Whitney Canyon-Carter Creek field complex in the Overthrust Belt area of Unita County, Wyoming. The Company s #1-30 Duck Federal well is currently producing approximately 5.1 MMcf of gas, 60 barrels of associated condensate and 250 barrels of water per day from the Mission Canyon Formation. Gas production appears to have stabilized since running a tubing string in the fall of 2006 after an extended shut-in, although we continue to see a slowly declining water cut. The Company and its partners have identified several potential drilling locations from the 3-D seismic shot in a 23 square mile area. The Company has a 28.75% working interest in the #1-30 Duck Federal well.

In addition, the Company has agreed to participate for a 28.75% working interest in the re-drilling of an existing well, the UPRC #25-1, which directly offsets the #1-30 Duck well. The Company was informed by the operator that the drilling rig it expected to use to drill the re-entry of the UPRC #25-1 well has been released to drill a well for another operator. The operator has not advised the Company when it expects to have a rig for the re-entry.

North Stockyard Project. The Company s first development well in the North Stockyard Creek field in Williams County, North Dakota, the Harstad #1-15H, has been drilled to a vertical depth of 10,000 to evaluate the hydrocarbon potential of the Bluell formation. The well was then horizontally drilled in a southeasterly direction for a distance of approximately 4,800 within the Bluell porosity zone, and intermediate casing was set through the curved portion of the hole. The well is currently producing approximately 100 Bbls of oil per day, 65 Mcf of gas per day, and 80 barrels of water per day, and we anticipate that the operator will propose an acid based fracture treatment to improve the daily production rates. Depending on the Harstad well s production performance, the Company expects that additional development wells may be drilled on the acreage in which the Company has an interest. It is anticipated that extended reach horizontal drilling of the type employed in drilling the Harstad well can significantly improve the production rates of wells in this field. The Company has a 20% working interest in 3,116 gross acres in the project.

Texas and Gulf Coast Region

Nome Field. The Company has producing interests in the Nome Field in Jefferson County, Texas, which produces from the Yegua formation. This field was discovered in 1994, and our interpretation of 3D seismic over the field has identified undeveloped fault blocks, structural closures, and associated bright spot locations. The Company s first well, the Sun Fee GU #1-ST (Sun Fee Well), produces from the upper Yegua at an average rate of 5.9 MMcf/day and 493 Bbls/day (8.9 MMcfe/day) as of March 1, 2007. When the well reached payout on October 13, 2004 (production at that time was over 19.0 MMcfe per day), PYR was placed in pay status as a working interest participant in the well. Based on pooling of lands into the Sun Fee Sidetrack Unit (the Sidetrack Unit) by the operator, our current net revenue interest in the well and associated lands is 5.7%, consisting of a 5.19% working interest with a 1.5% overriding royalty interest. We and the other working interest partners control approximately 4,200 of gross leasehold acres in the project. Our revenues and costs associated with the production from the Sun Fee Well, as well as our costs incurred on the Nome Project, are subject to a net profits agreement with the Trust.

We are currently in litigation with the operator of the Sun Fee Well, Samson Lone Star L.P. (Samson), concerning, among other matters, Samson s pooling of certain lands into the production unit and the corresponding reduction in our working interest. The outcome of the litigation will determine our working interest and revenue interest. See Part II, Item 1 of this document for further details.

An additional well, in which the Company has an 8.33% working interest, the Nome-Long #1, has been completed in the Nome Field. The well logged about 135 feet of potential Yegua gas sand. Sales from this well had been delayed pending the construction of the Nome Central Facility by the operator. With this facility now complete, the Nome-Long #1 well is currently producing at March 5, 2007, 6.8 MMcf and 236 Bbls of oil per day on a 13/64th choke from limited perforations (26 feet) in the Yegua Formation. The operator has indicated that it will flow test this lower interval before adding an additional 97 feet of uphole perforations to the flow stream. As a result of our ongoing dispute with Samson and even though PYR has paid its full share of all drilling and related costs, Samson has reneged on its offer to process PYR s gas, thereby forcing PYR to seek alternative methods to get its share of gas to market. PYR is considering all of its options both legally and operationally in regards to this matter. Based on current production information and entitlement, the Company is under-produced by approximately 49 MMcf with a current sales value of approximately $397,000 as of February 28, 2007. However, the Company is not entitled to recover this amount until such time the operator s share of remaining reserves are insufficient to settle the production imbalance. Our interests in wells drilled in this prospect are subject to the Trust s initial net profits interest of 50%.

The Nome-Harder #1, which is an offset to the Nome-Long #1well by approximately 2,685 feet to the northeast, has reached total depth of approximately 15,000 . The well has been logged, and upon the recommendation of the operator, a production liner is being run. Completion and testing operations should begin shortly. During drilling the well encountered encouraging gas shows, and only after testing will any definitive determination be able to be made with regard to the wells productivity. PYR fully expects Samson to force PYR to take its gas in kind as is the case with the Nome-Long #1 well. We will vigorously defend our interest. Although the operator has not provided us with additional information, we believe, based on reports provided to us by third party consultants engaged by us, that there are a number of other potential drilling locations. PYR is participating with an approximate 4.167% working interest in this Yegua project. Our interest in this well will be subject to the aforementioned Trust net profits interest of 50%.

Madison Prospect. Production levels from the Company s Maness Gas Unit #1 well, located in Jefferson County, Texas, continues to improve after it was shut-in for an extended period over a year ago and is currently producing approximately 425 Bbls of oil per day, 1.5 MMcf of gas per day, and 67 Barrels of water. The Company has a 12.5% working interest in the Maness Gas Unit #1 well.

In the Madison prospect, the Company participated in drilling the Wall GU#1 well, in which the Company has a 17.5% working interest. This well is a development well that offsets the Maness GU#1 well. The Wall well was originally completed during December 2006. However, during completion operations, the well suffered significant near wellbore damage. After planned mitigation measures failed to remedy the damage, the Company, in agreement with the operator, re-entered the well and has successfully sidetracked the well to the productive interval, which was encountered up dip to the original penetration. The sidetrack well has been completed, production liner has been run, and the well was perforated April 4, 2007. It is now flowing on a highly restricted 7/64th choke at a rate of approximately 190 Bbls of oil per day, 270 Mcf of gas per day, and no water. We anticipate production to increase significantly as the well choke is slowly increased following our initial clean-up flow period. With a successful completion, we anticipate that the operator will propose additional development drilling. Our mapping suggests that we may have from three to five additional drilling locations. PYR s interest in wells drilled in this prospect is subject to the Trust s initial net profits interest of 50%.

West Westbury Prospect, located in Jefferson County, Texas, targets Yegua sand reservoirs. The prospect, based on 3D seismic interpretation and amplitude analysis, is located approximately 1.5 miles to the southwest of an analog well, in which PYR does not have an interest, completed in October of 2004. This analog well had cumulative production of 28.6 Bcfe through September 2006, averaging 36.8 MMcf of gas and 1,655 barrels of condensate per day at that time. Subsequently, a second well, in which PYR also does not have an interest, the Paggi Broussard #2, was drilled and was producing 30.1 MMcfd and 1,477 barrels of condensate per day according to an October report. Both of these wells, along with PYR s West Westbury prospect, are interpreted to be in the same general structural block. Within this same area an additional well, the #1 Mixson Land, has been drilled and completed, and surface production facilities are being installed, indicating that this is a probable producer. While PYR does not own an interest in this test, the well offsets our West Westbury prospect area by approximately 3600 feet, and will be the third recent test by the operator on this structure. PYR is evaluating the viability of drilling a well on its West Westbury prospect based on these nearby wells and our technical interpretation of how they relate geologically. PYR owns 100% working interest in the prospect and is currently marketing a portion of this prospect to industry partners.

Bayou Duralde Project, is located in Evangeline Parish, Louisiana. The Fontenot # 1 exploration well, which reached a total depth of 10,650 feet on June 6, 2006, had been undergoing numerous tests and evaluations. However, based on these results, the operator has decided that the well is uneconomic and has proposed that the well be plugged to which the Company has consented. PYR has a 15% working interest in the project.

California

In California, the operator of the East Lost Hills prospect area located in Kern County has continued plugging operations of six wells drilled in 1998 through 2002, in which the Company has a 12.1193% working interest. The process is nearly complete and should be finished by the end of April. The Company s net plugging costs are expected to be approximately $900,000. The Company has previously recognized this obligation as an asset retirement obligation, a current liability, on its balance sheet and does not expect the payment of these plugging costs to impact its Consolidated Statements of Operations.

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Results of Operations

The financial information with respect to the three and six months ended February 28, 2007 that is discussed below is unaudited. The results of operations for interim periods are not necessarily indicative of the results of operations for the full fiscal year.

Three Months Ended February 28, 2007 Compared to Three Months Ended February 28, 2006

The second quarter ended February 28, 2007, for the fiscal year ending August 31, 2007 (fiscal 2007), resulted in net income of $458,000 compared to net income of $175,000 for the second quarter ended February 28, 2006, for the fiscal year ended August 31, 2006 (fiscal 2006).

	Three Months Ended February 28, 2007	Three Months Ended February 28, 2006	Increase (Decrease) Amount	Increase (Decrease) Percent
	($ in thousands, except for per unit prices and costs)			
Operating Results:				
Revenues				
Gas production revenues	$ 1,403	$ 1,250	$ 153	12%
Oil production revenues	815	816	(1)	0%
Natural gas liquids revenues	123	3	120	4000%
Other products	28		28	100%
Total revenues	$ 2,369	$ 2,069	$ 300	14%
Interest income	$ 44	$ 68	($24)	(35%)
Operating Expenses				
Lease operating expense	$ 290	$ 331	($41)	(12%)
Production taxes, gathering and transportation expense	190	141	49	35%
Net profits expense	(203)	320	(523)	(163%)
Depletion, depreciation, amortization and accretion	906	509	397	78%
General and administrative:				
General and administrative(1)	544	584	(40)	(7%)
Non-cash stock-based compensation	142		142	100%
Total operating expenses	$ 1,869	$ 1,885	($16)	(1%)
Interest Expense	$ 98	$ 89	$ 9	10%
Production Data:				
Natural gas (Mcf)	240,381	174,903	65,478	37%
Oil (Bbls)	15,348	13,477	1,871	14%
Natural gas liquids (Bbls)	3,675	73	3,602	4934%
Combined volumes (Mcfe)	354,519	256,203	98,316	38%
Daily combined volumes (Mcfe/d)	3,939	2,847	1,092	38%
Average Prices:				
Natural gas (per Mcf)	$ 5.84	$ 7.15	($1.31)	(18%)
Oil (per Bbl)	53.10	60.53	(7.43)	(12%)
Natural gas liquids (per Bbl)	33.58	38.55	(4.97)	(13%)
Combined (per Mcfe)	6.71	8.08	(1.37)	(17%)
Average Costs (per Mcfe):				
Lease operating expense	$ 0.82	$ 1.29	($0.47)	(36%)
	0.54	0.55	(0.01)	(2%)

Production taxes, gathering and transportation expense				
Net profit expense	(0.57)	1.25	(1.82)	(146%)
Depletion, depreciation, amortization and accretion	2.55	1.99	0.56	28%
General and administrative[1]	1.53	2.28	(0.75)	(33%)
Interest Expense	0.28	0.35	(0.07)	(20%)

[1] Excluding non-cash stock based compensation.

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Oil and Gas Revenues. Oil and gas revenues increased 14% to approximately $2.4 million for the three months ended February 28, 2007 from approximately $2.1 million for the same period in 2006 due to a 38% increase in production offset in part by a decrease in natural gas and oil prices of 18% and 12%, respectively. Average volume increases added approximately $602,000 of production revenues offset, in part, by a reduction of production revenues of $330,000 associated with the impact of a decrease in average prices. Sale of sulfur from the #1-30 Duck Federal well generated revenues of $37,000 in fiscal 2007. For the three months ended February 28, 2007, production increases more than offset production declines. Three wells, one well in each of Texas, Oklahoma and Wyoming, contributed 50% of the Company s oil and gas revenues.

In preparation of production and revenue estimates, based on the accrual method of accounting, the Company utilizes the best information available including monthly production information from the operator, if available, and the normal correlation of the expected price to an index. In the first quarter of fiscal 2007, an anomaly occurred with respect to the correlation of the expected price to an index for our Oklahoma and Texas properties resulting in an over-accrual of revenues of approximately $176,000, which, when adjusted in the second quarter of 2007, resulted in lower revenues for the second quarter of 2007. This anomaly did not impact the results for the six month period.

On a Mcf equivalent basis, total production volumes for the second quarter in fiscal 2007 increased 38% from total production for the same period in fiscal 2006. Additional information concerning production is in the following table.

	Three Months Ended February 28, 2007			**Three Months Ended February 28, 2006**		
	Oil & NGLs (Bbls)	**Natural Gas** (Mcf)	**Total** (Mcfe)	**Oil & NGLs** (Bbls)	**Natural Gas** (Mcf)	**Total** (Mcfe)
Oklahoma	1,380	100,152	108,432	1,705	77,757	87,987
Texas	7,997	98,372	146,354	9,385	94,865	151,175
Utah	4,818	730	29,638	1,889	388	11,722
Wyoming	4,304	40,979	66,803			
Other	524	148	3,292	571	1,893	5,319
Total	19,023	240,381	354,519	13,550	174,903	256,203

Lease Operating Expenses. Our per unit of production lease operating expenses decreased 36% from $1.29 per Mcfe in the second quarter of fiscal 2006 to $0.82 per Mcfe for the same period in fiscal 2007. This per unit of production decrease is principally attributed to a reduction in workover costs on wells located in Texas in fiscal 2007 compared to fiscal 2006, offset, in part, by an increase in lease operating expenses associated with the #1-30 Duck Federal well and two new Scharff wells added since the second quarter of fiscal 2006. Lease operating expenses decreased by 12% in fiscal 2007 compared with fiscal 2006.

Production Taxes, Gathering and Transportation Expenses. Production taxes as a percentage of natural gas and oil revenues averaged 6.0% for the second quarter in both fiscal 2007 and fiscal 2006. Production taxes are primarily based on wellhead values of production and vary across the different areas that our wells are located. Total production taxes increased as a result of higher production revenues, due to an increase in production volumes offset, in part, by a decrease in average prices. Gathering, transportation and other sales expenses increased by $35,000 in 2007 compared with the same period in 2006. This increase is attributed principally to gathering and transportation costs associated with production from two new Scharff wells located in Oklahoma, which commenced production in the first quarter of fiscal 2007.

Net Profits Expense. The net profits interest agreement with Venus Exploration Trust (the Trust) arose out of the acquisition of properties from Venus Exploration Inc. (Venus) in May 2004. The amount of the Trust s net profits interest is either 25% or 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after the Trust received an aggregate total of $3.3 million in net profits. Pursuant to the net profits interest agreement, the Company is obligated to pay the Trust when revenues exceed expenditures on a cash basis; however, for financial reporting purposes, the Company records an expense under the accrual method. In accordance with generally accepted accounting principles, as of the quarter ended November 30, 2006, the Company had a net liability of $203,000 to the Trust. As a result of additional capital expenditures during the quarter ended February 28, 2007, the Company does not have a net profits liability. Therefore, the Company reversed its previous recognition of expense. The Company will not be obligated to record an additional net profits expense until profits are realized in excess of capital expenditures. As of February 28, 2007, the Company has paid to the Trust net profits expenses totaling approximately $2.0 million.

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Depletion, Depreciation, Amortization and Accretion Expense. Depletion, depreciation, amortization and accretion expense was $906,000 for the second quarter ended February 28, 2007 compared with $509,000 for the same period in the prior year. The increase is principally attributed to depletion expense which increased $401,000. Depletion expense increase is the result of a 38% increase in production volumes in the second quarter in fiscal 2007 as compared to the same period in the prior year. The weighted average depletion rate for the Company s full cost pool increased from $1.95 per Mcfe in the second quarter of the prior year to approximately $2.54 per Mcfe in the second quarter of the current year. The rate increase is attributed to the inclusion of costs of previously unevaluated properties in the amortizable base of the full cost pool and capitalized legal costs associated with the Nome prospect, for which no additional reserves have been added. Under the full cost pool method of accounting, impairment costs of unevaluated properties, previously excluded from the amortizable base of the depletable full cost pool, are added to the full cost pool depletable base resulting in an increase in the depletion rate.

General and Administrative Expenses. General and administrative expenses, excluding non-cash stock-based compensation, during the quarter ended February 28, 2007 decreased by approximately $39,000, or 7%, from the same period in 2006. Costs associated with Samson s tender offer incurred during the second quarter of fiscal 2007 were offset by a reduction in overhead costs associated with our Texas office and a decrease in franchise taxes. As of January 1, 2007, we closed our Texas office and have engaged one or both of the geologists from time-to-time on an hourly consulting basis. As a result of higher production volume levels, general and administrative costs per unit of production decreased from $2.28 per Mcfe in the second quarter of the prior year to $1.53 per Mcfe for the current period.

Non-cash charges for stock-based compensation was $142,000 for the second quarter in fiscal 2007. Effective September 1, 2006, the Company commenced recognizing compensation costs for all share-based payments in accordance with Statement for Financial Accounting Standards No. 123R.

Interest Income. Interest income decreased by $24,000 to $44,000 for the second quarter ended February 28, 2007 compared to the same period in 2006, principally due to lower cash and short-term investments balances.

Interest Expense. During the quarters ended February 28, 2007 and 2006, we recorded interest expense of $98,000 and $89,000, respectively. The interest expense, primarily associated with the Company s convertible notes due May 24, 2009, increased due to an increase in convertible note principal balances (resulting from adding previously accrued interest to the principal). In fiscal 2007, the Company paid a loan origination fee of $5,000 associated with the execution of the Company s Credit Facility.

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Six Months Ended February 28, 2007 Compared to Six Months Ended February 28, 2006

The six month period ended February 28, 2007 fiscal 2007 resulted in net income of $841,000 compared to net income of $631,000 for the six month period ended February 28, 2006 for fiscal 2006.

	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006	Increase (Decrease) Amount	Increase (Decrease) Percent
	($ in thousands, except for per unit prices and costs)			
Operating Results:				
Revenues				
Gas production revenues	$ 3,134	$ 2,492	$ 642	26%
Oil production revenues	1,655	1,576	79	5%
Natural gas liquids revenues	162	4	158	3950%
Other products	37		37	100%
Total revenues	$ 4,988	$ 4,072	$ 916	22%
Interest income	$ 100	$ 115	($15)	(13%)
Operating Expenses				
Lease operating expense	$ 714	$ 575	$ 139	24%
Production taxes, gathering and transportation expense	383	265	118	45%
Net profits expense	(141)	580	(721)	(124%)
Depletion, depreciation, amortization and accretion	1,803	866	937	108%
General and administrative:				
General and administrative(1)	1,112	1,087	25	2%
Non-cash stock-based compensation	200		200	100%
Total operating expenses	$ 4,071	$ 3,373	$ 698	19%
Interest Expense	$ 190	$ 188	$ 2	1%
Production Data:				
Natural gas (Mcf)	504,487	305,147	199,340	65%
Oil (Bbls)	30,083	26,019	4,064	16%
Natural gas liquids (Bbls)	4,445	133	4,312	3242%
Combined volumes (Mcfe)	711,655	462,059	249,596	54%
Daily combined volumes (Mcfe/d)	3,932	2,553	1,379	54%
Average Prices:				
Natural gas (per Mcf)	$ 6.21	$ 8.17	($1.96)	(24%)
Oil (per Bbl)	55.01	60.57	(5.56)	(9%)
Natural gas liquids (per Bbl)	36.49	33.98	2.51	7%
Combined (per Mcfe)	7.01	8.81	(1.80)	(20%)
Average Costs (per Mcfe):				
Lease operating expense	$ 1.00	$ 1.24	($0.24)	(19%)
Production taxes, gathering and transportation expense	0.54	0.57	(0.03)	(5%)
Net profit expense	(0.20)	1.25	(1.45)	(116%)
Depletion, depreciation, amortization and accretion	2.52	1.87	0.65	35%
General and administrative(1)	1.56	2.35	(0.79)	(34%)

Interest Expense	0.27	0.41	(0.14)	(34%)

(1) Excluding non-cash stock based compensation.

Oil and Gas Revenues. Oil and gas revenues increased by approximately $916,000 million, or 22%, to approximately $5.0 million for the six months ended February 28, 2007 from approximately $4.1 million for the same period in fiscal 2006 due to a 54% increase in production, offset, in part, by a decrease in average oil and gas prices. Average Mcfe production increases added $1.6 million of oil and gas revenues while decreases in average prices reduced oil and gas revenues by approximately $741,000. Sale of sulfur from the #1-30 Duck Federal well generated revenues of $37,000 in fiscal 2007. For the six months ended February 28, 2007, production increases more than offset production declines. Three wells, one well in each of Texas, Oklahoma and Wyoming, contributed 48% of the Company s oil and gas revenues for the first six month of fiscal 2007.

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On a Mcf equivalent basis, total production volumes for the first six months in fiscal 2007 increased 54% from total production for the same period in fiscal 2006. Additional information concerning production is in the following table.

	Six Months Ended February 28, 2006			Six Months Ended February 28, 2007		
	Oil & NGLs (Bbls)	Natural Gas (Mcf)	Total (Mcfe)	Oil & NGLs (Bbls)	Natural Gas (Mcf)	Total (Mcfe)
Oklahoma	3,051	231,125	249,436	3,440	131,665	152,305
Texas	14,368	198,240	284,453	17,776	170,858	277,514
Utah	10,876	1,333	66,594	3,833	608	23,606
Wyoming	5,163	73,529	104,512			
Other	1,066	260	6,660	1,103	2,016	8,634
Total	34,528	504,487	711,655	26,152	305,147	462,059

Lease Operating Expenses. Our per unit of production lease operating expenses decreased 19% from $1.24 per Mcfe in the first six months of fiscal 2006 to $1.00 for the same period in fiscal 2007. This per unit of production decrease is principally attributed to an increase in production volumes. Total lease operating expenses increased 24%, or $139,000.

Production Taxes, Gathering and Transportation Expenses. Production taxes as a percentage of natural gas and oil revenues averaged 6.2% for the first six months of fiscal 2007 compared to 5.7% for the same period in fiscal 2006. Production taxes are primarily based on wellhead values of production and vary across the different areas that our wells are located. The increase in the average production tax rate is attributed to increased production from locations with higher production tax rates. Total production taxes increased as a result of higher production revenues and a higher average production tax rate. Gathering, transportation and other sales expenses, principally incurred on our Scharff wells located in Oklahoma, increased by $43,000 in fiscal 2007 compared with the same period in fiscal 2006.

Net Profits Expense. As described above, the net profits interest agreement with the Trust arose out of the acquisition of properties from Venus in May 2004. The amount of the Trust s net profits interest is either 25% or 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after the Trust has received an aggregate total of $3.3 million in net profits. Pursuant to the net profits interest agreement, the Company is obligated to pay the Trust when revenues exceed expenditures on a cash basis; however, for financial reporting purposes, the Company records an expense under the accrual method. In accordance with generally accepted accounting principles, as of August 31, 2006, the Company had a net liability of $231,000 to the Trust. As a result of additional capital expenditures and a payment of $89,000 during the six month period ended February 28, 2007, the Company does not have a net profits liability. Therefore, the Company reversed its previous recognition of expense, net of the payment. The Company will not be obligated to record an additional net profits expense until profits are realized in excess of capital expenditures. As of February 28, 2007, the Company has paid to the Trust net profits expenses totaling approximately $2.0 million.

Depletion, Depreciation, Amortization and Accretion Expense. Depletion, depreciation, amortization and accretion expense was $1.8 million for the first six months of fiscal 2007 compared with $866,000 for the same period in fiscal 2006. The increase is principally attributed to depletion expense which increased $940,000. Depletion expense increase is the result of a 54% increase in production volumes in the first six months of fiscal 2007 as compared to the same period in fiscal 2006. The weighted average depletion rate for the Company s full cost pool increased from $1.83 per Mcfe in the first six months of fiscal 2006 to $2.51 per Mcfe in the first six months of fiscal 2007. The rate increase is attributed to the inclusion of costs of certain previously unevaluated properties in the amortizable base of the full cost pool and capitalized legal costs associated with the Nome prospect, for which no additional reserves have been added. Under the full cost pool method of accounting, impairment costs of unevaluated properties, previously excluded from the amortizable base of the depletable full cost pool, are added to the full cost pool depletable base resulting in an increase in the depletion rate.

General and Administrative Expenses. General and administrative expenses, excluding non-cash stock-based compensation, during the first six months of fiscal 2007 increased by approximately $26,000, or 2%, from the same period in fiscal 2006. As a result of higher production volume levels, general and administrative costs per unit of production decreased from $2.35 per Mcfe in the first six months of fiscal 2006 to $1.56 per Mcfe for the same period in fiscal 2007.

Non-cash charges for stock-based compensation was $200,000 for the first six months of fiscal 2007. Effective September 1, 2006, the Company commenced recognizing compensation costs for all share-based payments in accordance with Statement for Financial Accounting Standards No. 123R.

Interest Income. Interest income decreased by $15,000 to $100,000 for the first six months of fiscal 2007 compared to the same period in 2006 due to lower cash and short-term investments balances.

Interest Expense. During the six-month periods ended February 28, 2007 and 2006, we recorded interest expense of $190,000 and $188,000, respectively. The interest expense, principally associated with the Company s convertible notes due May 24, 2009, increased due to an increase in convertible note principal balances (resulting from adding previously accrued interest to the principal) and payment of a loan origination fee of $5,000 associated with the execution of the Company s Credit Facility. The Company elected to pay accrued interest on the convertible notes of approximately $184,000 and $175,000 for the six months ended February 28, 2007 and 2006, respectively, by increasing the outstanding balance of the Convertible Notes.

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.

Reserve Estimates:

Our estimates of oil and natural gas reserves, by necessity, are projections based on geological and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected from there may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material.

Many factors will affect actual net cash flows from production, including the following: the amount and timing of actual production; curtailments due to weather; supply and demand for natural gas; curtailments or increases in consumption by natural gas purchasers; and changes in governmental regulations or taxation.

Property, Equipment and Depreciation:

We follow the full cost method to account for our oil and gas exploration and development activities. Under the full cost method, all costs associated with acquisition, exploration and development activities, including costs of unsuccessful exploration and legal costs incurred to defend the Company s revenue interest in the Nome prospect, are capitalized and subjected to depreciation and depletion. Depletable costs also include estimates of future development costs of proved reserves. Costs related to undeveloped oil and gas properties may be excluded from depletable costs until those properties are evaluated as either proved or unproved. The net capitalized costs are subject to a ceiling limitation based on the estimated present value of discounted future net cash flows from proved reserves. As a result, we are required to estimate our proved reserves at the end of each quarter, which is subject to the uncertainties described in the previous section. Gains or losses upon disposition of oil and gas properties are treated as adjustments to capitalized costs, unless the disposition represents a significant portion of the Company s proved reserves.

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Revenue Recognition:
The Company recognizes oil and gas revenues from its interests in producing wells as oil and gas is produced and sold from these wells. As of February 28, 2007, based on the Company s entitlement, the Company was under-produced by an aggregate of 35 MMcfs with a fair market value of approximately $296,000.
Deferred Tax Allowance:
As of February 28, 2007, the Company had a substantial deferred tax asset, consisting principally of tax loss carryforwards valued at approximately $16.0 million. This deferred tax asset is fully offset by a deferred tax allowance as the Company continues to believe it is more likely than not that such asset will be realized due to the historical uncertainty in the volatility of oil and gas prices, the industry in general and past historical losses. The Company continues to re-evaluate this estimate.
Recent Accounting Pronouncements