PYR ENERGY CORP
Form 10KSB
November 22, 2006

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U.S. SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-KSB

þ	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
	For the fiscal year ended August 31, 2006
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. 0-20879

PYR ENERGY CORPORATION
(Name of small business issuer in its charter)

Maryland	**95-4580642**
(State or 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)*

Registrant s telephone number, including area code:(303) 825-3748

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

Title of Each Class	**Name of Each Exchange on Which Registered**
$.001 Par Value Common Stock	American Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

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

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

Form 10-KSB. Yes þ   No o

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

The registrant s revenues for the fiscal year ended August 31, 2006 were $10.3 million. As of November 15, 2006, the registrant had 37,993,259 common shares outstanding, and the aggregate market value of the common shares held by non-affiliates was approximately $32,682,570*. This calculation is based upon the closing sale price of $1.01 per share on November 15, 2006.

* Without asserting that any of the issuer s directors or executive officers, or the entities that own 10% or greater of the registrant s shares of common stock, are affiliates, the shares of which they are beneficial owners have been deemed to be owned by affiliates solely for this calculation.

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PART I

ITEM 1 and ITEM 2. *DESCRIPTION OF BUSINESS AND PROPERTIES*

General

PYR Energy Corporation (referred to as PYR, the Company, we, us and our) is an independent oil and gas explo and production company, engaged in the exploration, development and acquisition of crude oil and natural gas reserves. 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.

Our current focus is on the Rocky Mountain, Texas and Gulf Coast regions as described below. During the fiscal years ended August 31, 2006 and 2005, we focused our development and exploration efforts on the drilling phase of our high potential development and exploration projects in the Rocky Mountain and Gulf Coast regions.

The Company s offices are located at 1675 Broadway, Suite 2450, Denver, Colorado 80202. The telephone number is (303) 825-3748, the facsimile number is (303) 825-3768 and the Company s web site is www.pyrenergy.com. The Company s periodic and current reports filed with the Securities and Exchange Commission (the SEC) can be found on the Company s website at www.pyrenergy.com and on the SEC s website at www.sec.gov.

PROPERTIES AND BUSINESS ACTIVITIES

Oil and Gas Exploration and Development Activities

Our development, exploration, and acquisition activities are focused primarily in select areas of the Rocky Mountains, 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 these core areas and in other areas that meet our production and exploration criteria. We are currently producing over 5.1 million cubic feet of gas equivalent per day and are 100% unhedged.

Rocky Mountain Exploration

Mallard Project. At our Mallard project in Uinta County, Wyoming, three and one-half inch tubing has been successfully installed inside of the seven-inch casing of the well-bore for the #1-30 Duck Federal well. From mid-September through mid-November 2006, the operator encountered difficulties in removing a retrievable mechanical plug in the tubing that was installed for safety reasons during installation of the tubing and the well was shut-in pending the removal of either this plug or the tubing. As a result of this difficulty, along with the shut-down for the actual tubing operation, the well was off-line from August through mid-November, 2006, and production was down sharply. Thirty days prior to the tubing installation, production averaged 4.0 MMcf per day of gas, 61 barrels of associated condensate, and 325 barrels of water. Since mid-November 2006, when the well was recently brought back on-line, it has produced on average approximately 5.0 MMcf per day of gas, 75 barrels of condensate and 371 barrels of water using a 16/64th choke. Production is expected to improve as the well continues to clean-up and stabilize. The 23 square miles of 3-D seismic that the Company is participating in to define future drilling locations has been completed. The Company is participating with a 28.75% working interest in the #1-30 Duck Federal well and 3-D seismic. The Company believes there are additional proved undeveloped (PUD) locations to drill within its acreage position. The #1-30 Duck Federal represents a development well within the Whitney Canyon-Carter Creek Field complex. Of the more than 2.1 Tcf that has been produced to date from this Field, over 80% of the production is from the Mission Canyon formation, which is the primary producing formation for the #1-30 Duck Federal.

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In addition, PYR and the other working interest owners have begun the process to re-enter and sidetrack the now-abandoned UPRC 25-1 well, located approximately 2400 north of the Duck Federal. This well encountered the Mission Canyon approximately 400 high to the Duck Federal, but failed to penetrate the main porosity zone due to steep dips. As a result, it produced only around 587 MMcf and 5000 barrels condensate prior to being plugged and abandoned by another operator in May 2001. PYR believes economic reserves can be found within the porosity zones, accessible via a sidetrack. The Company expects to be drilling this well before the end of December 2006.

The Company has also participated in road and location construction for the Teal #36-1 pending the outcome of the 3D survey.

Pioneer Prospect. The Company has recently leased approximately 1,800 net acres in this project in Wyoming.

Ryckman Creek Project. We have leased approximately 1,820 net acres, covering the majority of the abandoned Ryckman Creek field, in the Overthrust region of southwestern Wyoming. Ryckman Creek, located 6 miles east of our Mallard prospect, was discovered in 1975 and produced approximately 250 Bcfe prior to abandonment. We believe that recoverable gas reserves were stranded in Ryckman Creek upon abandonment. Potential reserves exist in multiple zones, including the Twin Creek, Nugget, and Thaynes Formations, in the field. The Company owns 100% of this project and we are studying our alternatives, which include selling our interest down or possibly farming out the project.

Montana Foothills Project. Following the plugging and abandonment of the Flesher Pass exploratory well in August 2005, the Company re-evaluated the exploration prospects associated with its undeveloped acreage in the project and elected to release all of its undeveloped acreage position. As a result, all remaining acreage positions expired by August 1, 2006. As previously stated, the Company wrote down all of its costs in the amortizable base of the full cost pool in the first quarter ended November 30, 2005.

Texas and Gulf Coast Exploration:

Nome Field. This field was discovered in 1994, and our interpretation of subsequently acquired 3D seismic over the field indicates the presence of numerous undeveloped fault blocks. Multiple structural closures and associated bright spot locations have been identified at Nome based on the 3D seismic. One such location resulted in the Sun Fee GU #1-ST well (the Sun Fee Well), which produces from the upper Yegua, and was initiated in late May 2004, and beginning in early June 2004, averaged approximately 19 MMcfe per day. The well continues to produce at an average rate of 11 MMcfe/day (8.1 MMcf/day and 500 BO/day). At the end of October 2006 the well had cumulative production of approximately 11.7 Bcfe. When the well reached payout on October 13, 2004, 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. Wells drilled in this prospect are subject to a 50% net profits interest agreement, reducing to 25% after the payout of the net profit interest to Venus Exploration 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.

In September, 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 parties, PYR Energy Corporation, as Plaintiff, and Samson Resources Company and Samson Lone Star Partnership LLP (Samson), as Defendant. In its ruling, the Court held (1) that Samson did not have authority to pool PYR s original overriding royalty interest in the Sun Fee Well, located in

Jefferson County, Texas into the Sidetrack Unit and, therefore, PYR is entitled to the interest in the production from the Sun Fee Well that is attributable to this 3.5% overriding royalty from the day of first production, rather than the 1.5% overriding royalty interest amount upon which Samson has been paying, and (2) that, although Samson did have authority to pool PYR s working interest into the unit, PYR would be able to maintain its claim for breach of contract against Samson for joining non-productive acreage into the unit.

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In its complaint in this suit, PYR has alleged that Samson breached its underlying contracts with PYR when Samson included in the Sidetrack Unit properties in which Samson held the exclusive interests and which PYR contends are non-productive. PYR believes that this action by Samson improperly diluted PYR s unit-based interest. 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 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.

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 Venus Exploration Trust (Trust). The net profits agreement arose out of our acquisition of properties from Venus Exploration Inc. (Venus) in May 2004. The initial net profit interest under the agreement varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3.3 million in net profits proceeds has been paid to the Trust. The amount of net profits liability recognized over time is subject to fluctuation, because both revenues and costs associated with production from any wells and other costs incurred on the designated exploration and exploitation project areas will increase or decrease over a given period of time.

The Tindall #1, offsetting by approximately 1600 feet the Sun Fee Well, is a location that the Company owns 100% of the working interest. Samson filed a lawsuit seeking a judicial declaration of Samson s exclusive right to operate the Tindall well and injunctive relief enjoining the Company from continuing its drilling operations or serving as operator. As of September 6, 2006, the State District Court for Jefferson County, Texas, 58th Judicial District, issued a final summary judgment in PYR s favor against Samson and ending this suit. The Company is evaluating the economic viability of drilling the Tindall #1 well given the current volumes of gas, oil and water produced from the offsetting Sun Fee Well.

At the Nome Field, in Jefferson County, Texas, the Nome-Long #1 well has reached total depth of 15,800 feet. Based on log analysis, the Company believes that the well has found significant pay in the upper Yegua (EY-3) sandstone at a measured depth of 14,200 feet. Multiple wireline tests indicate formation pressure averaging approximately 12,700 psi in this zone. Additional pay was logged in shallower Yegua zones. The operator has commenced completion operations and we anticipate that subsequent testing of the indicated pay zone will take place by the end of December 2006. PYR is participating with an 8.33% working interest. Wells drilled in this prospect are subject to the Trust s initial net profits interest of 50%.

Cotton Creek Prospect. Cotton Creek Prospect, located in Jefferson County, Texas, is adjacent to the Nome project. The prospect is located approximately one mile west of the productive Sun Fee Well in the same structural fault block. PYR owns a 50% working interest in the acreage position and controls with its partner approximately 500 acres of term minerals in addition to a modest amount of term leasehold. PYR s ownership in this prospect is not in dispute; however, the other working interest owner has connected PYR s ownership in this project to the Bankruptcy case and has indicated that they will not participate in any activity in this prospect until the issues in the Bankruptcy case have been resolved. PYR s ownership in this project consists of predominately a term fee mineral interest. As long as there is production elsewhere on these minerals the Company s interest is not in danger of reverting or expiring. The Company will evaluate its options once the legal matters and partner issues have been resolved. Wells drilled in this prospect are subject to the Trust s initial net profits interest of 25%.

Madison Prospect. At the Madison project in the northern part of the Constitution Field, located in Jefferson County, Texas, the Maness Gas Unit #1 well, which had recently undergone an extensive and complicated workover during the 2006 summer to replace production tubing damaged by corrosion and scaling, is flowing at approximately 1.95 MMcfe per day to sales at this time. The well continues to build pressure and volume, and we expect the well to continue to improve. At the time of shut-in for the workover, the Maness GU#1 had cumulative production of 2.6 Bcfe and was averaging gross production of approximately 400 BO/day and 1.5 MMcf/day (3.9 MMcfe/day). The Company is participating with a 12.5% working interest. This well is subject to the Trust s initial net profits interest of 50%.

Also in the Madison Prospect, the Wall #1 well, a PUD location offsetting the Maness GU#1 well, has reached total depth and completion operations are in progress. The Company believes the well will be flowing to sales in the

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next several weeks. Based on log analysis, this well found approximately 20 feet of net pay in the middle Yegua zone, Doyle sandstone, at a depth of 14,050 feet. Wireline tests indicate gas production and formation pressure averaging approximately 11,645 psi. An additional 10 feet of net pay were logged and tested in shallower zones. Pending results from this test, the Company anticipates that additional PUD locations should be drilled in the summer of 2007. PYR is participating for a 17.5% working interest in this development well. Wells drilled in this prospect are subject to the Trust s initial net profits of 50%.

Tortuga Grande Prospect. At the Tortuga project in Smith County, Texas, the Chisum #1 well was completed in the lower Rodessa section and is currently producing at approximately 820 Mcfe per day. Rodessa production, within 3 miles to the north and northeast of the Chisum location, has yielded cumulative production ranging up to 6.4 Bcfe per well. Additional drilling locations to fully exploit the Rodessa potential in the project area have been identified and it is expected that approximately 25 square miles of 3D seismic data will be acquired to better delineate the additional drilling opportunities. The Company owns a 28.57% working interest in the Chisum well and surrounding acreage. The Company and the operator also control approximately 9,800 acres of leasehold in the project. Wells drilled in this prospect are subject to the Trust s net profits interest.

Merganser Prospect. This prospect, located in Leon County, Texas, targets Cotton Valley and Bossier sandstone reservoirs. In February 2006, PYR sold its interest in approximately 250 acres, in the prospect, for $280,239 to Encana Oil & Gas.

Bayou Duralde Prospect. In 2006, the Company participated in the completion of the Fontenot #1 well located in Evangeline Parish, Louisiana on the Bayou Duralde prospect. The well has been drilled and cased to a total depth of 10,650 to evaluate the Cockfield and Frio formations. Given the expense of connecting to a pipeline, the operator is considering the most cost effective method to evaluate this well. They evaluated their initial approach of testing through a sales line and are now considering an alternative that would replicate a flow test to a sales line, placing back pressure on the well, and flowing it to atmosphere for a period of time to ultimately determine its commerciality. PYR is participating with a 15% working interest before payout and 17.5% after payout in the project. PYR, along with its partners, controls approximately 3,000 acres of leasehold. Wells drilled in this prospect are subject to the Trust s initial net profits interest of 25%.

West Westbury Prospect. This prospect, which consists of 388 acres in which PYR has a 100% working interest, is located in Jefferson County, Texas, and targets Yegua sand reservoirs. The prospect, based on 3D seismic amplitude, is located approximately 1.5 miles to the southwest of an analog well that was completed in October of 2004 and in which PYR does not have an interest. This analog well, located in the same fault block but subject to different seismic attributes, had cumulative production of 21.9 Bcfe through April 2006 and is currently producing 35 MMcf of gas and 1700 barrels of condensate per day. Recently, a second well in which PYR does not have an interest, the Paggi Broussard #2, was drilled and is producing 28MMcfd and 1500 barrels of condensate per day. The Paggi Broussard #2 also is in the same fault block with different seismic attributes than PYR s acreage. PYR is currently marketing its interest in this exploration prospect to industry partners.

Wilburton Field. In the Wilburton field located in Latimer County, Oklahoma, the Scharff #7-1 was recently completed and is producing approximately 16 MMcf per day from a total of 181 net feet of commingled pay in the Cecil, Shay, and Wister B sandstone at measured depths ranging from 11,830 to 14,222 feet. Four shallower zones behind pipe contain a total of approximately 48 net feet of pay, based on log analysis. The Scharff #8-1 was recently completed after the Scharff #7-1 and is producing approximately 13 MMcf per day from a total of 112 net feet of pay in the Cecil sandstone at a measured depth of 11,300 feet, based on log analysis. Additionally, an approximate 44 net feet of pay was logged in shallower zones. The Scharff #6-1 and #5-1 continue to produce at 6 MMcf and 25 MMcf per day respectively. PYR owns a 2.42% working interest in each of the Scharff #5-1, 6-1, 7-1, and 8-1 wells.

Hansford Project. Located in Hansford County of the Texas Panhandle, the Hansford project is a development project at the southern end of the Houghton Embayment. Main producing horizons within the Hansford area include the upper and lower Morrow as well as the Chester. On December 20, 2005, the Company closed a strategic acquisition of additional interest in the Hansford project, from multiple private entities, for $1.78 million in cash. The acquisition of the Hansford County property consisted of approximately 1.64 Bcf of proved reserves and 2,265 acres of undeveloped leasehold. This acquisition allowed the Company to consolidate working interest and

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operations in a field which offers significant development drilling opportunities. As of August 31, 2006, in a report prepared by Ryder Scott Company, L.P., the Company s estimated proved reserves in the Hansford project are approximately 2.5BCF, of which 65% are classified as PUD. PYR owns a 100% working interest on the majority of the acreage, which includes three producing wells, two PUD locations. The Lackey GU #2, completed earlier this year is currently producing between 200 and 300 Mcf per day. The Lackey GU #1, which underwent a work over is currently producing between 200 and 300 Mcf per day. The Company owns a 100% working interest in both the Lackey GU #1 and Lackey GU #2. Future drilling opportunities are currently being evaluated.

OTHER

Utah

PYR owns working interests ranging from 19% to 57% in four wells (one of which reached payout in August) located in Duchesne and Uintah Counties, State of Utah. PYR acquired its interests in these wells through the acquisition from Venus in 2004.

San Joaquin Basin, California

The Company continues to maintain some leasehold in two prospects, *Bulldog and Wedge*, in this region.

Blizzard. The Blizzard project is located in the southern portion of the San Joaquin Basin of Kern County, California. Blizzard is a combination exploration and exploitation project offsetting the Rio Viejo Field. Management has sold the Company s leasehold position while retaining an overriding royalty.

Bulldog Prospect. This project is a 2D seismically identified natural gas and condensate prospect located adjacent to the giant Kettleman North Dome field in the San Joaquin Basin. This prospect can be best characterized as a classic footwall fault trap, similar to the many known footwall fault trap accumulations that have produced significant quantities of hydrocarbons throughout the San Joaquin basin. The Company may drill, farm out, or sell its position in this prospect in the future.

Wedge Prospect. This is a seismically identified Temblor prospect located northwest of and adjacent to the East Lost Hills deep gas discovery. During the first fiscal quarter of 2001, we acquired approximately 17 miles of proprietary, high effort 2D seismic data and combined this data with existing 2D seismic data in order to refine what we interpret as the up-dip extension of the East Lost Hills structure. Our seismic interpretation shows that the same trend at East Lost Hills extends approximately ten miles farther northwest of the East Lost Hills Area of Mutual Interest and can be encountered as much as 3,000 feet higher. The Company may drill, farm out, or sell its position in this prospect in the future.

Markets and Major Customers

Sales from our ownership interests in producing properties to major unaffiliated customers (customers accounting for 10% or more of gross revenue), all representing purchasers of oil and gas, for the years ended August 31, 2006 and 2005 are as follows:

	2006	**2005**
Customer A	26%	
Customer B	20%	38%

Customer C	11%	
Customer D		22%
Customer E		10%

We are not confined to, nor dependent upon, any one purchaser or small group of purchasers. Accordingly, the loss of a single purchaser would not materially affect our business because we believe we would be able to find another purchaser.

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Employees and Office Space

At November 15, 2006, we had seven full-time employees. Our Denver office has six full-time employees including two geologists. Our San Antonio office has one full-time employee and two consulting geologists and one consulting engineer. We believe that our relationship with our employees is satisfactory. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We lease approximately 3,800 square feet of office space in Denver, Colorado for our executive and administrative offices. We have an additional office in San Antonio, Texas, in which we lease approximately 4,300 square feet.

Business Strategy

Our objective is to increase stockholder value per share by adding reserves, production, cash flow, earnings and net asset value. To accomplish this objective, we intend to develop our proved undeveloped locations and to capitalize on our technical expertise in identifying, evaluating and participating in the exploratory drilling and development of deep, structurally complex formations. We also intend to build on our experience and our competitive strengths, which include:

- our inventory of Texas and Rocky Mountain development and exploration projects,
- our control of pre-drill exploration phases, and
- our ability to identify suitable development and exploitation drilling opportunities.

To implement our strategy, we seek to:

Execute Exploration and Development Drilling on Our Undrilled Projects. We have interests in several exploration projects in the Texas Gulf Coast and select areas of the Rocky Mountains. In the Rocky Mountains, our most notable project is the Mallard prospect located in southwestern Wyoming. We are currently expanding our drilling activities on the Mallard prospect with the drilling of the UPRC 25-1 well and completion of 3-D seismic. In the Texas Gulf Coast, we have interests in several exploration projects and PUD locations to be drilled in the future. We are currently attempting completion of recently drilled wells in the Nome and Madison prospects.

Continue to Internally Generate Exploration Prospects. We believe that by continuing to generate exploitation and exploration prospects with a special emphasis on applying our seismic expertise to deep, structurally complex formations, we can identify prospects with significant oil and gas reserve potential. We then assemble acreage positions on these prospects. This enables us to control costs during the pre-drill phases of exploration and to sell a portion of our interests to industry participants, while potentially retaining a carried interest in the initial drilling.

Evaluate Low Risk, Shallow Exploitation and Development Drilling Opportunities. As part of our ongoing strategy, we are evaluating lower risk drilling opportunities relative to our higher risk, internally generated, exploration projects. If found to be appropriate, these opportunities can provide the Company with suitable internal rates of return on investment, geographic and risk diversification, and exposure to reserves and potential cash flow. We continue to review and evaluate additional development and exploitation opportunities as they arise.

Continue a Disciplined Acquisition Process. As part of our ongoing strategy, we diligently look for properties or opportunities with significant upside in our core areas. Through our personal contacts, industry knowledge and expertise, we look to find under-worked properties or missed structures, that with strong operatorship, may be productive.

Certain Definitions

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.

AMI. Area of Mutual Interest.

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

Bbl/d. One Bbl per day.

Bc/d. Barrels of condensate daily.

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

Bcfe. One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

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 through the tanks. 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.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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 the depth of a stratigraphic horizon 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.

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.

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.

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Mcf/d. One Mcf per day.

Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil.

MMcf. One million cubic feet of natural gas.

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.

Participant Group. The individuals and/or companies that, together, comprise the ownership of 100% of the working interest in a specific well or project.

PV-10 value. The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization or federal income taxes and discounted using an annual discount rate of 10%.

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.

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 developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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.

Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Re-entry. Entering an existing well bore to redrill or repair.

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.

Sidetrack. An operation involving the use of a portion of an existing well to drill a second hole at some desired angle into previously undrilled areas. From this directional start, a new hole is drilled to the desired formation depth and casing is set in the new hole and tied back to the casing from the existing well.

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Tcf. One trillion cubic feet.

3-D Seismic. The method by which a three-dimensional image of the earth s subsurface is created through the interpretation of reflection 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.

Proved Reserves

For fiscal years 2006 and 2005, our proved reserve estimates for our United States oil and gas properties were prepared by Ryder Scott Company, L.P., an independent petroleum engineering firm, and, in accordance with SEC guidelines, are the estimated quantities of oil, natural gas and plant products which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. The Standardized Measure shown in the table is not intended to represent the current market value of our estimated natural gas and oil reserves.

	As of August 31,	
	2005	**2006**
Estimated Net Proved Reserves:		
Natural gas (MMcf)	3,668	5,738
Oil & NGLs (MBbls)	566	628
Total (MMcfe)	7,064	9,508
Percent proved developed	61.8%	61.7%
Standardized Measure (in thousands)(1)	$ 28,752	$ 28,685

(1) The Standardized Measure represents the present value of estimated future cash inflows from proved natural gas and oil reserves, less future development, production, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using market prices for natural gas and oil at each of August 31, 2005 and 2006, which were $11.74 per Mcf of gas and $66.95 per bbl of oil at August 31, 2005 and $5.49 per Mcf of gas and $67.12 per Bbl of oil at August 31, 2006.

At August 31, 2006, our estimated total proved reserves increased 34% increase over August 31, 2005 estimated total proved reserves. This increase resulted principally from the addition of estimated proved reserves from new proved developed producing and proved undeveloped additions related to development in the expanded Yegua trend of south Texas and completion of the #1-30 Duck Federal well in Uinta County Wyoming. As of August 31, 2006, proved developed producing reserves are estimated at 4.431 Bcfe, while proved developed non-producing reserves are estimated at 1.437 Bcfe. Proved undeveloped reserves are estimated at 3.640 Bcfe. The Company s Canadian oil and gas properties do not have proved reserves.

Using current market product prices in effect at the end of the fiscal year and a discount rate of 10% as prescribed by SEC regulation, our total discounted future after-tax net cash flows were estimated to be approximately $28.7 million for total proved reserves for the years ended August 31, 2006 and 2005. Reserve additions in fiscal 2006 offset a decrease of 53% in gas prices from August 31, 2005. The present value of future net cash flows does not purport to be an estimate of the fair market value of our proved reserves. An estimate of the future value would also take into consideration, among other things, anticipated changes in future prices and costs, the expected

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recovery of reserves in excess of proved reserves and a discount factor more representative of the time value of money and the risks inherent in producing oil, natural gas and plant products.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment and the existence of development plans. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. Further, the estimated future net revenues from proved reserves and the present value thereof are based upon certain assumptions, including geologic success, prices, future production levels and cost that may not prove correct over time. Predictions about prices and future production levels are subject to great uncertainty, and the meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they are based.

Production and Prices

The following table sets forth information regarding net production of oil, natural gas and natural gas liquids, and certain price and cost information for fiscal years ended August 31, 2005 and 2006:

	As of August 31, 2005	As of August 31, 2006
Production Data:		
Natural gas (Mcf)	392,067	915,973
Oil (Bbls)	61,948	53,049
NGLs (Bbls)	336	5,267
Combined volumes (MMcfe)	766	1,266
Daily combined volumes (MMcfe/d)	2.1	3.5
Average Prices:		
Natural gas (per Mcf)	$ 7.54	$ 7.32
Oil (per Bbl)	$ 50.04	$ 63.55
NGLs (per Bbl)	$ 29.53	$ 34.83
Combined (per Mcfe)	$ 7.96	$ 8.15
Average Costs (Per Mcfe):		
Lease operating expenses	$ 0.94	$ 1.22
Production taxes, gathering and transportation	$ 0.50	$ 0.54
Depreciation, depletion and amortization	$ 1.13	$ 2.05
General and administrative	$ 2.49	$ 1.78

Productive Wells

The following table summarizes information at August 31, 2006, relating to the productive wells in which we owned a working interest as of that date. Productive wells consist of producing wells and wells capable of

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production. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Gross			Net		
	Oil	Gas	Total	Oil	Gas	Total
Location						
Canada		1	1		0.05	0.05
California	3		3	0.24		0.24
Oklahoma	17	27	44	2.86	0.85	3.71
Texas	20	15	35	4.42	4.41	8.83
Utah	5		5	1.68		1.68
Wyoming		1	1		0.29	0.29
TOTAL	45	44	89	9.20	5.60	14.80

Drilling Activities

During the past two fiscal years, we participated in the drilling of the following exploration and development wells:

During the fiscal year ended August 31, 2006, PYR participated in the drilling of three exploration wells, with one exploration well in the Wyoming Overthrust, one in the southeast Gulf Coast, and one in Louisiana. PYR also participated in drilling a workover in Hansford County, Texas and another one in the Constitution Field in the Gulf Coast. During this time period, the Company participated in drilling seven PUDs total, with one drilled in Hansford, Texas (100% WI), five drilled in the Willburton Field in Oklahoma (2.42% WI), and one in the Gulf Coast area (17.5% WI). As of mid-November 2006, both workovers were producing to sales, all of the exploratory wells were either producing or in the process of being completed, and all of the PUD wells were also either producing to sales or in the process of being completed.

During the fiscal year ended August 31, 2005, we participated in the drilling of two exploration wells in the Wyoming Overthrust, one exploration well in East Texas, and two development wells in Oklahoma. Four of these wells were successful, and one of the Wyoming Overthrust exploration wells was plugged and abandoned in November 2005. Additionally in fiscal year 2005, the Company participated in several well workovers in Texas and Oklahoma.

Although there is no assurance that any additional wells will be drilled, we anticipate we may drill additional exploration and development wells during fiscal 2007 on our projects in the Texas Gulf Coast and Rocky Mountains. The actual number of wells drilled will be dependent on several factors, including the results of our ongoing exploration efforts and the availability of capital.

Full Cost Method of Accounting for Oil and Gas Properties

The Company utilizes the full cost method of accounting for oil and gas activities and in accordance with the full cost method of accounting, the Company maintained separate cost centers for its oil and gas activities in the United States and Canada for fiscal years 2006 and 2005. Under this method, all costs associated with acquisition, exploration and development activities are capitalized by cost center. Capitalized costs, excluding costs of investments in unproved properties and major development projects, are subject to a ceiling test limitation computed separately for each cost center. Under this method, we are required to record a permanent impairment provision if the net book value of our oil and gas properties (net of related deferred taxes) exceeds a ceiling value equal to the sum of (i) the present value of the future cash inflows from proved reserves, tax effected and discounted at 10% per annum, and (ii) the cost of unevaluated properties. The ceiling test is computed by country and at the end of each quarter. The oil and gas prices used in calculating future cash inflows in the United States are based upon the market price on the last day of the accounting period. Oil and gas prices are generally volatile; and if the market prices at a period end date have decreased, we may have to record an impairment. A loss may also be generated by the transfer of significant early stage exploratory costs to the oil and gas property cost pool that is subject to the ceiling test. These losses typically occur when significant costs are transferred to the oil and gas property full cost pool as a result of an unsuccessful project without commercial oil and gas production. For the years ended August 31, 2006 and 2005, no property impairment charges were recorded for the Company s United States properties.

In accordance with the full cost method of accounting, the Company s Canadian oil and gas investment, comprised principally of non-producing acreage (used for exploration and development activities), is recorded in a separate full cost pool. During 2005, the Company recorded a non-cash impairment of $580,000 of its initial oil and gas investment in Canada as the book value of the properties exceeded the fair market value of such properties. The Company decided to limit future expenditures in Canada.

Developed and Undeveloped Acreage

The following table sets forth information as of August 31, 2006 relating to our leasehold acreage.

	Gross Acres		Net Acres	
State	**Developed**	**Undeveloped**	**Developed**	**Undeveloped**
California	400	5,000	33	5,000
Louisiana		2,665		2,615
Oklahoma	5,659		197	
Texas	25,633	8,306	9,610	7,048
Utah	4,943		1,504	
Wyoming	640	7,872	184	5,100
TOTAL	**37,275**	**23,843**	**11,528**	**19,763**

Competition

We compete with numerous companies in virtually all facets of our business, including many companies that have significantly greater resources. These competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties than our financial or personnel resources permit. Our ability to establish and increase reserves in the future will be dependent on our ability to select and acquire suitable producing properties and prospects for future exploration and development. The availability of a market for oil and gas production depends upon numerous factors beyond the control of producers, including but not limited to the availability of other domestic or imported production, the locations and capacity of pipelines, and the effect of federal and state regulation on that production.

Government Regulation of the Oil and Gas Industry

General. Our business is affected by numerous laws and regulations, including energy, environmental, conservation, tax and other laws and regulations relating to the energy industry. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of injunctive relief or both. Moreover, changes in any of these laws and regulations could have a material adverse effect on our business. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

We currently operate one property. We believe that operations where we own interests comply in all material respects with applicable laws and regulations and that the existence and enforcement of these laws and regulations have no more restrictive an effect on our operations than on other similar companies in the energy industry.

The following discussion contains summaries of certain laws and regulations and is qualified in its entirety by the foregoing and by reference to the full text of the laws and regulations described.

Federal Regulation of the Sale and Transportation of Oil and Gas. Various aspects of our oil and gas operations are or will be regulated by agencies of the federal government. The Federal Energy Regulatory Commission, or FERC, regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or NGA, and the Natural Gas Policy Act of 1978, or NGPA. In the past, the federal government has regulated the prices at which oil and gas could be sold. While first sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA in 1978. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act.

The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993, and resulted in a series of Orders being issued by FERC requiring interstate pipelines to provide transportation services separately, or unbundled, from the pipelines sales of gas and to provide open access transportation on a nondiscriminatory basis that is equal for all natural gas shippers.

We do not believe that we will be affected by these or any other FERC rules or orders materially differently than other natural gas producers and marketers with which we compete.

The FERC also has issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the FERC does not have jurisdiction over services provided on those facilities, then those facilities and services may be subject to regulation by state authorities in accordance with state law. A number of states have either enacted new laws or are considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our anticipated gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that we would be affected by such regulation any differently than other natural gas producers or gatherers. In addition, the FERC s approval of transfers of previously-regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to FERC regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future.

We conduct certain operations on federal oil and gas leases, which are administered by the Minerals Management Service, or MMS. Federal leases contain relatively standard terms and require compliance with detailed MMS regulations and orders, which are subject to change. Among other restrictions, the MMS has regulations restricting the flaring or venting of natural gas, and has proposed to amend those regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and operations. The MMS issued a final rule that amended its regulations governing the valuation of crude oil produced from federal leases. This rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil produced from federal leases, and was further modified by amendments to the June 2000 MMS rules, effective July 1, 2004. Also, the MMS promulgated new Federal Gas Valuation rules, effective June 1, 2005 (70FR 11869, March 10, 2005) concerning calculation of transportation costs, including the allowed rate of return in the calculation of actual transportation costs in non-arm s length arrangements and addresses various other related matters. We cannot predict whether this new gas rule will become effective, nor can we predict whether the MMS will take further action on oil and gas valuation matters. However, we do not believe that any such rules will affect us any differently than other producers and marketers of crude oil with which we will compete.

Additional proposals and proceedings that might affect the oil and gas industry are pending before Congress, the FERC, the MMS, state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position. No material portion of our business is subject to re-negotiation of profits or termination of contracts or subcontracts at the election of the federal government.

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State Regulation. Our operations also are subject to regulation at the state and, in some cases, county, municipal and local governmental levels. This regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells and the disposal of fluids used and produced in connection with operations. Our operations also are or will be subject to various conservation laws and regulations. These include (1) the size of drilling and spacing units or proration units, (2) the density of wells that may be drilled, and (3) the unitization or pooling of oil and gas properties. In addition, state conservation laws, which frequently establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but (except as noted above) does not generally entail rate regulation. These regulatory burdens may affect profitability, but we are unable to predict the future cost or impact of complying with such regulations.

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 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 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 government 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

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agencies continue to promulgate regulations that limit the disposal and permitting options for certain hazardous and non-hazardous wastes.

Our operations will involve the use of gas fired compressors to transport collected gas. These compressors are subject to federal and state regulations for the control of air emissions. Title V status for a facility results in significant increased testing, monitoring and administrative and compliance costs. To date, other compressor facilities have not triggered Title V requirements due to the design of the facility and the use of state-of-the-art engines and pollution control equipment that serve to reduce air emissions. However, in the future, additional facilities could become subject to Title V requirements as compressor facilities are expanded or if regulatory interpretations of Title V applicability change. Stack testing and emissions monitoring costs will grow as these facilities are expanded and if they trigger Title V. The U.S. Environmental Protection Agency and some other state environmental agencies have increased their focus on control of minor gas emission leaks from pipelines, compressors, tanks, and related oil and gas production and storage equipment in response to ozone non-attainment requirements increasing the costs and complexity of our operations. 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 operations. At this time, we have no plans to make any material capital expenditures for environmental control facilities.

Title to Properties

As is customary in the oil and gas industry, only a preliminary title examination is conducted at the time we acquire leases or enter into other agreements to obtain control over interests in acreage believed to be suitable for drilling operations. In many instances, our partners have acquired rights to the prospective acreage and we have a contractual right to have our interests in that acreage assigned to us. In some cases, we are in the process of having those interests so assigned. Prior to the commencement of drilling operations, a thorough title examination of the drill site tract is conducted by independent attorneys. Once production from a given well is established, the operator will prepare a division order title report indicating the proper parties and percentages for payment of production proceeds, including royalties. We believe that titles to our leasehold properties are good and defensible in accordance with standards generally acceptable in the oil and gas industry.

Risk Factors

In evaluating the Company, careful consideration should be given to the following risk factors, in addition to the other information included or incorporated by reference in this annual report. In addition, the Forward-Looking Statements located herein, describe additional uncertainties associated with our business and the forward-looking statements included or incorporated by reference. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock.

We have a limited history of drilling and monitoring oil and gas properties. Our operations to date have consisted solely of evaluating geological and geophysical information, acquiring acreage positions, generating exploration prospects, and drilling a limited number of wells on deep oil and gas prospects. We currently have seven full-time employees. Our future financial results depend primarily on (1) our ability to discover commercial quantities of oil and gas; (2) the market price for oil and gas; (3) our ability to continue to generate potential

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exploration prospects; and (4) our ability to fully implement our exploration and development program. We cannot predict that our future operations will be profitable. In addition, our operating results may vary significantly during any financial period. These variations may be caused by significant periods of time between discovery and development of oil or gas reserves, if any, in commercial quantities.

We may not discover commercially productive reserves. Our future success depends on our ability to economically locate oil and gas reserves in commercial quantities. Except to the extent that we acquire properties containing proved reserves or that we conduct successful exploration and development activities, or both, our proved reserves, if any, will decline as reserves are produced. Our ability to locate reserves is dependent upon a number of factors, including our participation in multiple exploration projects and our technological capability to locate oil and gas in commercial quantities. We cannot predict that we will have the opportunity to participate in projects that economically produce commercial quantities of oil and gas in amounts necessary to meet our business plan or that the projects in which we elect to participate will be successful. There can be no assurance that our planned projects will result in significant reserves or that we will have future success in drilling productive wells at economical reserve replacement costs.

Exploratory drilling is an uncertain process with many risks. Exploratory drilling involves numerous risks, including the risk that we will not find any commercially productive oil or gas reservoirs. The cost of drilling, completing and operating wells is often uncertain, and a number of factors can delay or prevent drilling operations, including:

- unexpected drilling conditions,
- pressure or irregularities in formations,
- equipment failures or accidents,
- adverse weather conditions,
- compliance with governmental requirements,
- shortages or delays in the availability of drilling rigs and the delivery of equipment, and
- shortages of trained oilfield service personnel.

Our future drilling activities may not be successful, nor can we be sure that our overall drilling success rate or our drilling success rate for activities within a particular area will not decline. Unsuccessful drilling activities could have a material adverse effect on our results of operations and financial condition. Also, we may not be able to obtain any options or lease rights in potential drilling locations that we identify. Although we have identified a number of potential exploration projects, we cannot be sure that we will ever drill them or that we will produce oil or gas from them or any other potential exploration projects.

Our exploration and development activities are subject to reservoir and operational risks. Even when oil and gas is found in what is believed to be commercial quantities, reservoir risks, which may be heightened in new discoveries, may lead to increased costs and decreased production. These risks include the inability to sustain deliverability at commercially productive levels as a result of decreased reservoir pressures, large amounts of water, or other factors that might be encountered. As a result of these types of risks, most lenders will not loan funds secured by reserves from newly discovered reservoirs, which would have a negative impact on our future liquidity. Operational risks include hazards such as fires, explosions, craterings, blowouts (such as the blowout experienced at our initial exploratory well), uncontrollable flows of oil, gas or well fluids, pollution, releases of toxic gas and encountering formations with abnormal pressures. In addition, we may be liable for environmental damage caused by previous owners of property we own or lease. As a result, we may face substantial liabilities to third parties or governmental entities, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur substantial losses.

We expect to maintain insurance against some, but not all, of the risks associated with drilling and production in amounts that we believe to be reasonable in accordance with customary industry practices. The occurrence of a significant event, however, that is not fully insured could have a material adverse effect on our financial condition and results of operations.

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Our operations require large amounts of capital and our cash resources are limited. Our current development plans will require us to have large amounts of cash in order to make large capital expenditures for the exploration and development of our oil and gas projects. Under our current capital expenditure budget, we expect to spend between $8 and $12 million on exploration and development activities during our fiscal year ending August 31, 2007. Also, we must secure substantial capital to explore and develop our other potential projects. Historically, we have funded our capital expenditures through the issuance of equity. Volatility in the price of our common stock, which may be significantly influenced by our drilling and production activity, may impede our ability to raise money quickly, if at all, through the issuance of equity at acceptable prices. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- our success in locating and producing reserves in other projects,
- the level of production from existing wells, and
- prices of oil and gas.

Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. Debt financing, if obtained, could lead to:

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

If our revenues were to decrease due to lower oil and gas prices, decreased production or other reasons, and if we could not obtain capital through a credit facility or otherwise, our ability to execute our development plans, obtain and replace reserves, or maintain production levels could be greatly limited. We may consider selling down a portion of our interests in some of our exploration and development projects to industry partners to generate additional funds to finance our capital budget.

We depend heavily on exploration success and subsequent success in developing our exploration projects. Our future growth plans rely heavily on discovering reserves and initiating production in Texas, the Gulf Coast, and the Rocky Mountains. Our development plan includes the need to discover reserves and establish commercial production through exploratory drilling and development of our existing properties. We cannot be sure, though, that our planned projects will lead to significant reserves that can be economically extracted or that we will be able to drill productive wells at anticipated finding and development costs. If we are able to record reserves, our reserves will decline as they are depleted, except to the extent that we conduct successful exploration or development activities or acquire other properties containing proved reserves.

We depend on industry alliances. We attempt to limit financial exposure on a project-by-project basis by forming industry alliances where our technical expertise can be complemented with the financial resources and operating expertise of more established companies. While entering into these alliances limits our financial exposure, it also limits our potential revenue from successful projects. Industry alliances also have the potential to expose us to uncertainty if our industry partners are acquired or have priorities in areas other than our projects. Despite these risks, we believe that if we are not able to form industry alliances, our ability to fully implement our business plan could be limited, which could have a material adverse effect on our business.

We have limited control over our oil and gas projects. We focus primarily on creating exploration opportunities and forming industry alliances to develop those opportunities. We serve as the operator of only one of our projects. As a result, we have only a limited ability to exercise control over a significant portion of a project s operations or the associated costs of those operations. The success of a project is dependent upon a number of factors that are outside our areas of expertise and control. These factors include:

the abilities of the operator of the project,

the availability of leases with favorable terms and the availability of required permitting for projects,

the availability of future capital resources to us and the other participants to be used for purchasing leases and drilling wells,

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the approval of other participants for the purchasing of leases and the drilling of wells on the projects, and

the economic conditions at the time of drilling, including the prevailing and anticipated prices for oil and gas.

Our reliance on the operator and other project participants and our limited ability to directly control project costs could have a material adverse effect on our expected rates of return.

Oil and gas prices are volatile and an extended decline in prices could hurt our business prospects. Our future profitability and rate of growth and the anticipated carrying value of our oil and gas properties will depend heavily on then prevailing market prices for oil and gas. We expect the markets for oil and gas to continue to be volatile. If we are successful in continuing to establish production, any substantial or extended decline in the price of oil or gas could:

have a material adverse effect on our results of operations,

limit our ability to attract capital,

make the formations we are targeting significantly less economically attractive,

reduce our cash flow and borrowing capacity, and

reduce the value and the amount of any future reserves.

Various factors beyond our control will affect prices of oil and gas, including:

worldwide and domestic supplies of oil and gas,

the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls,

political instability or armed conflict in oil or gas producing regions,

the price and level of foreign imports,

worldwide economic conditions,

marketability of production,

the level of consumer demand,

the price, availability and acceptance of alternative fuels,

the availability of processing and pipeline capacity,

weather conditions, and

actions of federal, state, local and foreign authorities.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and gas. In addition, sales of oil and gas are seasonal in nature, leading to substantial differences in cash flow at various times throughout the year.

Accounting rules may require write-downs. 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 a write-down for accounting purposes if the ceiling is exceeded. If a write-down is required, it would result in a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and gas properties is not reversible at a later date.

We face risks related to title to the leases we enter into that may result in additional costs and affect our operating results. It is customary in the oil and gas industry to acquire a leasehold interest in a property based upon a preliminary title investigation. In many instances, our partners have acquired rights to the prospective acreage and we have a contractual right to have our interests in that acreage assigned to us. In some cases, we are in the process of having those interests so assigned. If the title to the leases acquired is defective, or title to the leases one of our partners acquires for our benefit is defective, we could lose the money already spent on acquisition and development, or incur substantial costs to cure the title defect, including any necessary litigation. If a title defect cannot be cured or if one of our partners does not assign to us our interest in a lease acquired for our benefit, we will not have the right to participate in the development of or production from the leased properties. In addition, it is possible that the terms of our oil and gas leases may be interpreted differently depending on the state in which the property is located. For instance, royalty calculations can be substantially different from state to state, depending on each state s interpretation of lease language concerning the costs of production. We cannot guarantee that there will be no litigation concerning the proper interpretation of the terms of our leases. Adverse decisions in any litigation of this kind could result in material costs or the loss of one or more leases.

Limitations on the effectiveness of controls. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls can prevent all possible error or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Our industry is highly competitive and many of our competitors have more resources than we do. We compete in oil and gas exploration with a number of other companies. Many of these competitors have financial and technological resources vastly exceeding those available to us. We cannot be sure that we will be successful in acquiring and developing profitable properties in the face of this competition. In addition, from time to time, there may be competition for, and shortage of, exploration, drilling and production equipment. These shortages could lead to an increase in costs and delays in operations that could have a material adverse effect on our business and our ability to develop our properties. Problems of this nature also could prevent us from producing any oil and gas we discover at the rate we desire to do so.

Technological changes could put us at a competitive disadvantage. The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As new technologies develop, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at a substantial cost. If other oil and gas exploration and development companies implement new technologies before we do, those companies may be able to provide enhanced capabilities and superior quality compared with what we are able to provide. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If we are unable to utilize the most advanced commercially available technologies, our business could be materially and adversely affected.

Our industry is heavily regulated. Federal, state and local authorities extensively 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. The overall regulatory burden on the industry increases the cost of doing business, which, in turn, decreases profitability.

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Our operations must comply with complex environmental regulations. Our operations are subject to complex and constantly changing environmental laws and regulations adopted by federal, state and local governmental authorities. 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 could face significant liabilities to the government and third parties for discharges of oil, natural gas, produced water or other pollutants into the air, soil or water, and we could have to spend substantial amounts on investigations, litigation and remediation. 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.

Our business depends on transportation facilities owned by others. The marketability of our anticipated gas production depends in part on the availability, proximity and capacity of pipeline systems owned or operated by third parties. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

Attempts to grow our business could have an adverse effect. Because of our small size, we desire to grow rapidly in order to achieve certain economies of scale. Although there is no assurance that this rapid growth will occur, to the extent that it does occur, it will place a significant strain on our financial, technical, operational and administrative resources. As we increase our services and enlarge the number of projects we are evaluating or in which we are participating, there will be additional demands on our financial, technical and administrative resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the recruitment and retention of geoscientists and engineers, could have a material adverse effect on our business, financial condition and results of operations.

We may not be able to retain our listing on the American Stock Exchange. The American Stock Exchange has certain listing requirements in order for a company to continue to have their securities traded on this exchange. A company may risk delisting if its common stock trades at a low price per share for a substantial period of time. Should our stock trade at a low share price for a substantial period of time, or our net tangible equity be below certain levels, we may not be able to retain our listing.

We depend on key personnel. We have a small group of employees and are highly dependent on the services of our executive management, and our other geological, geophysical and land technical employees. The loss of the services of any of these persons could hurt our business.

Disclosure Regarding Forward-Looking Statements and Cautionary Statements

This annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, including statements regarding, among other items, our business and growth strategies, anticipated trends in our business and our future results of operations, market conditions in the oil and gas industry, our ability to make and integrate acquisitions, the outcome of litigation, if any, and the impact of governmental regulation. These forward-looking statements are based largely on our expectations and are subject to a number of risks and uncertainties, many of which are beyond our control. Actual results could differ materially from these forward-looking statements as a result of, among other things:

failure to obtain, or a decline in, oil or gas production, or a decline in oil or gas prices,

incorrect estimates of required capital expenditures, increases in the cost of drilling, completion and gas collection or other costs of production and operations,

an inability to meet growth projections, and

other risk factors set forth under Risk Factors in this annual report. In addition, the words believe, may, could, will, when, estimate, continue, anticipate, intend, expect and similar expressions, as they relate to PY business or our management, are intended to identify forward-looking statements.

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ITEM 3. ***LEGAL PROCEEDINGS***

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 (the Sun Fee Well), has 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 has no interest, many of which are non-productive. Samson has a large interest in the properties that Samson has 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 had authority to pool PYR s working interest into the unit, 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. Following a brief scheduling conference, the Court has requested that the parties discuss next steps, including (i) resuming the trial schedule for the issues and claims that remain unresolved by the Courts order, (ii) the immediate appeal on the rulings made to date in the order and/or (iii) mediation of the issues in dispute.

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 on the approximately

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400-acre property in which the Company holds 100% of the oil and gas interest. 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 on-going 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.

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

PART II

ITEM 5. *MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS*

Market for Common Equity

Our common stock has been listed on the American Stock Exchange under the market symbol PYR since December 8, 1999. The following table sets forth the range of high and low sales prices per share of our common stock for the periods indicated.

	High	Low
Fiscal Year Ended August 31, 2005		
First Quarter	$ 1.31	$ 0.90
Second Quarter	1.79	0.95
Third Quarter	1.99	1.20
Fourth Quarter	1.64	1.30
Fiscal Year Ended August 31, 2006		
First Quarter	$ 2.07	$ 1.00
Second Quarter	1.78	1.23
Third Quarter	1.57	1.18
Fourth Quarter	1.30	1.01

On November 15, 2006, the last reported sales price of our common stock on the American Stock Exchange was $1.01 per share.

Stockholders of Record

As of November 15, 2006, the number of record holders of our common stock was approximately 489.

Dividends

We have not declared or paid, and do not anticipate declaring or paying in the near future, any dividends on our common stock.

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Equity Compensation Plan Information

Equity Compensation Plan Information

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))* (c)
Equity compensation plans approved by security holders	2,331,750	$ 1.08	4,429,250
Equity compensation plans not approved by security holders			
Total	2,331,750	$ 1.08	4,429,250

* At August 31, 2006

ITEM 6. ***MANAGEMENT S DISCUSSION AND ANALYSIS OR PLAN OF OPERATIONS***

The following discussion should be read in conjunction with the Consolidated Financial Statements and Notes thereto referred to in Item 8. Financial Statements and Supplemental Data, and Items 1. and 2. Business and Properties Disclosures Regarding Forward-Looking Statements of this Form 10-KSB.

Overview

We are an independent oil and gas exploration and production company engaged in the exploration, development and acquisition of crude oil and natural gas reserves. We intend to increase stockholder value by profitably growing reserves and production, primarily through drilling operations and strategic acquisitions. We intend to participate in selected exploration projects as a working interest owner, currently as a non-operator, sharing both risk and rewards with our partners. In general, we are not able to commence additional exploratory drilling operations without outside industry participation. We have pursued, and will continue to pursue, exploration opportunities in regions where we believe significant opportunity for discovery of oil and gas exist. By attempting to reduce drilling risk through seismic technology, we seek to improve the expected return on investment in our oil and gas exploration projects.

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.

In mid-October 2005, we completed a private equity placement consisting of the sale of 6.275 million shares of common stock, priced at $1.30 per share, to a group of institutional and accredited individual investors and issued warrants to purchase 52,500 shares of common stock at a price of $1.30 per share to a financial advisory company as partial payment for services rendered. Proceeds from this placement of approximately $8.0 million net of offering costs were for general corporate purposes and costs associated with the Company s development drilling portfolio located principally in the Rocky Mountains and Texas.

Liquidity and Capital Resources

Our primary sources of liquidity historically have been from placements of common stock and convertible notes, and to a much lesser extent, 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. The Company is always looking at strategic alternatives to increase its shareholder value and is actively looking for acquisitions and/or merger possibilities. At August 31, 2006, we had approximately $5.6 million in working capital and cash of $6.2 million.

Cash Flows from Operating Activities

Net cash provided by operating activities was $4.4 million in 2006 compared with $1.9 million in 2005. The increase in net cash provided by operating activities was substantially due to a 69% increase in production revenues offset in part by an increase in operating expenses. See Results of Operations for discussion of changes in revenues and expenses. Non-cash charges increased 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 $815,000 in 2006 compared with an increase of $91,000 in 2005. During the year ended August 31, 2006, we used cash to pay all net profits due to the Venus Exploration Trust as of August 31, 2005 and for most of the net profits due for fiscal 2006. These payments account for the primary reduction in current liabilities and related use of cash associated with the changes in current assets and liabilities for fiscal 2006.

Operating cash flows are impacted by many variables, the most significant of which is 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 market conditions for these products. These factors are beyond our control and are difficult to predict.

Cash Flows used in Investing Activities

Our cash flows used in investing activities increased to approximately $9.2 million in fiscal 2006 from approximately $5.1 million in fiscal 2005. Investing activities included capital expenditures for oil and gas properties and furniture and equipment, net of proceeds from the sale of oil and gas properties. Our capital expenditures were approximately $9.6 million and $5.9 million in 2006 and 2005, respectively. The total for 2006 includes $5.9 million for drilling, development, exploration and exploitation, $1.7 million for the purchase of additional working interest in properties located in Hansford County, Texas and $2.0 million for leasehold costs including lease acquisitions, delay rentals and capitalized litigation costs incurred related to our Nome project and $29,000 for office furniture, fixtures and equipment. In 2005, we incurred approximately $4.3 million for drilling, development, exploration and exploitation, $1.6 million for leasehold expenditures and $10,000 for office furniture, fixtures and equipment.

In 2006 and 2005, we received proceeds of approximately $398,000 from sales of our interests in acreage located in our School Road prospect in California and acreage located in our Merganser prospect located in Leon County, Texas and $49,000 from the sale of a portion of our interests in prospects in Louisiana and Texas, respectively. During 2005, we received $750,000 for non-refundable option fees received from Suncor Energy Natural Gas America, Inc. (SENGAI) pursuant to an Exploration Option Agreement between the Company and SENGAI covering our Rogers Pass exploration project in the foothills of west-central Montana.

We currently anticipate our capital budget will be approximately between $9.0 and $12.0 million for fiscal year 2007, which we plan to use for a diverse portfolio of development and exploration wells in our core areas of operation. If our revenues were to decrease due to lower oil and gas prices, decreased production or other reasons, and if we could not obtain capital through a credit facility or otherwise, our ability to execute our development plans, obtain and replace reserves, or maintain production levels could be greatly limited. We may consider selling down a portion of our interests in some of our exploration and development projects to industry partners to generate additional funds to finance our 2007 capital budget. We are projecting that cash on hand, cash available from operating activities and funds from the partial sale of our interest in some prospects will be sufficient to fund our 2007 capital budget.

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Cash Flows provided by Financing Activities

Our fiscal 2006 financing activities provided cash of approximately $8.0 million. In mid-October 2005, the Company completed a private equity placement consisting of the sale of 6.275 million shares of common stock, priced at $1.30 per share, to a group of institutional and accredited individual investors and issued warrants to purchase 52,500 shares of common stock at a price of $1.30 per share to a financial advisory company as partial payment for services rendered. Proceeds from this placement of approximately $8.0 million net of offering costs were used for general corporate purposes and costs associated with the Company s 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, and the results of our activities. We anticipate spending approximately between $9.0 and $12.0 million 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.

Contractual Obligations

The following table summarizes the Company s obligations and commitments, as of August 31, 2006, to make future payments under its convertible notes payable and office lease for the periods specified (in thousands):

	Payments due by Period			
Contractual Obligations	**Total**	**2007**	**2008**	**2009**
Convertible Notes	$ 8,474	$	$	$ 8,474
Office Leases	93	70	23	
Total Contractual Cash Obligations	$ 8,567	$ 70	$ 23	$ 8,474

The above schedule assumes convertible note interest payments will be added to the principal amount (which is at the discretion of the Company), and the entire balance will be paid in full on maturity of May 24, 2009, and there will be no conversion of debt to common stock. In addition to the above obligations, if we elect to continue holding all our existing leases on a delayed rental basis, we would have to pay approximately $96,000 during the year ending August 31, 2007. The Company considers on a quarterly basis whether to continue holding all or part of each acreage block by making delay rental payments on existing leases.

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Results of Operations

The twelve months ended August 31, 2006 (2006) compared with the twelve months ended August 31, 2005 (2005)

	2006	2005	Increase (Decrease) Amount	Percent
	($ in thousands, except for per unit prices and costs)			
Operating Results:				
Revenues				
Gas production revenues	$ 6,706	$ 2,957	$ 3,749	127%
Oil production revenues	3,371	3,135	236	8%
Natural gas liquids revenues	184	10	174	1740%
Other products	58	0	58	
Total revenues	$ 10,319	$ 6,102	$ 4,217	69%
Operating Expenses				
Lease operating expense	$ 1,547	$ 721	$ 826	115%
Production taxes, gathering and transportation expense	689	383	306	80%
Net profits expense	829	1,343	(514)	(38)%
Depletion, depreciation, amortization and accretion	2,616	893	1,723	193%
Impairment of oil and gas properties	0	580	(580)	(100)%
General and administrative	2,256	1,909	347	18%
Total operating expenses	$ 7,937	$ 5,829	$ 2,108	36%
Interest Expense	$ 371	$ 343	$ 28	8%
Production Data:				
Natural gas (Mcf)	915,973	392,067	523,906	134%
Oil (Bbls)	53,049	61,948	(8,899)	(14)%
Natural gas liquids (Bbls)	5,267	336	4,931	1468%
Combined volumes (Mcfe)	1,265,869	765,771	500,098	65%
Daily combined volumes (Mcfe/d)	3,468	2,098	1,370	65%
Average Prices:				
Natural gas (per Mcf)	$ 7.32	$ 7.54	$ (0.22)	(3)%
Oil (per Bbl)	63.55	50.04	13.51	27%
Natural gas liquids (per Bbl)	34.83	29.53	5.30	18%
Combined (per Mcfe)	8.15	7.96	0.19	2%
Average Costs (per Mcfe):				
Lease operating expense	$ 1.22	$ 0.94	$ 0.28	30%
Production taxes, gathering and transportation expense	0.54	0.50	0.04	8%
Net profit expense	0.65	1.75	(1.10)	(63)%
Depletion, depreciation, amortization and accretion	2.05	1.13	0.92	81%
General and administrative	1.78	2.49	(0.71)	(28)%
Interest expense	0.29	0.45	(0.16)	(36)%

Operations during the fiscal year ended August 31, 2006 resulted in net income of approximately $2.3 million compared to net income of approximately $12,000 for the fiscal year ended August 31, 2005. The increase is attributed primarily to the increase in revenue relative to expense described below.

Oil and Gas Revenues. Oil and gas revenues increased by approximately $4.2 million, or 69%, to approximately $10.3 million in 2006 from approximately $6.1 million in 2005, of which 83% of the increase is attributed to a 65% increase in production volumes and 17% is attributed to a 3% increase in average price per Mcfe. The natural gas production increase of 523,906 Mcf is attributed to production from the new wells drilled and completed during 2006 , particularly the Scharff wells in Oklahoma, the Lackey Gas Unit #2 well in Texas and the #1-30 Duck Federal well in Wyoming and additional production received from the purchased interest in the Hansford producing wells in Texas. During 2006, average natural gas prices declined by approximately 3%. Average oil prices increased by approximately 27%, and were offset, in part, by a 14% decline in production. An increase in natural gas liquids (NGLs) production of 4,931 Bbls is attributed to new production from the #1-30 Duck Federal well located in Wyoming. Average NGL prices increased by 18% to $34.83 per Bbl.

During 2005, the Company commenced receiving its net revenue interest proceeds from the Sun Fee GU #1-ST well and the Maness #1 well, located in Texas, after the wells had reached payout during the fiscal year 2005. The oil and gas revenues from these wells approximate 28% and 55% of total oil and gas revenues for 2006 and 2005, respectively. Revenues from these wells are subject to a 50% net profits expense.

Lease Operating Expenses. Lease operating expenses increased from $721,000 in 2005 to $1.547 million in 2006. The increase is attributed to the workover on the Maness GU #1 well, new wells added, and additional operating costs associated with purchased interests in existing wells. Excluding the workover costs incurred in 2006, lease operating costs on a per unit of production basis was $0.96 per Mcfe in 2006 as compared to $0.94 per Mcfe in 2005. The 2006 workover costs on the Maness GU #1 well cost approximately $323,000, or $0.26 per Mcfe.

Production Taxes, Gathering and Transportation Expenses. Production taxes as a percentage of natural gas and oil revenues averaged 5.9% for both 2006 and 2005. Production taxes are primarily based on revenues from production sold and rates vary across the different areas that our wells are located. Accordingly, fluctuations in production taxes are directly associated with fluctuations in revenues. Production taxes for 2006 increased approximately 68% over 2005. Gathering, transportation and other sales expenses increased by $62,000 from 2005.

Net Profits Expense. The net profits interest agreement with Venus Exploration Trust (Trust) arose out of an 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 an aggregate total of $3.3 million in net profits. The 38% decrease in net profits expense from 2005 to 2006 resulted from additional costs incurred, a workover on the Maness well which also caused the well to be shut-in for several months and capital expenditures for drilling the Wall #1 well and the Nome-Long #1 well which have not been fully offset from current operating profits on the wells subject to the net profits obligation and will reduce any future net profits obligation until fully offset.

Depreciation, Depletion, Amortization and Accretion Expense. Depreciation, depletion, amortization and accretion expense increased by $1.723 million to $2.616 million in 2006 from $893,000 in 2005. The increase was primarily attributable to depletion expense which increased by $1.719 million from $861,000 in 2005 to $2.580 million in 2006. The depletion expense increase is the result of a 64% increase in production volumes and an increase in the average depletion rate from $1.12 per Mcfe to $2.038 per Mcfe. The rate increase is attributed primarily to the inclusion of costs of certain impaired unevaluated properties in the amortizable base of the full cost pool and additional costs, principally 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. We recorded $14,000 and $8,000 in depreciation expense associated with capitalized office furniture and equipment during 2006 and 2005, respectively. We recorded $22,000 and $25,000, respectively, for 2006 and 2005, of accretion of the unamortized discount of the Asset Retirement Obligation liability. For further discussion of the Asset Retirement Obligation, see Note 4 to the Financial Statements included in this Form 10-KSB.

Impairment and Abandonments. No impairment expense was recorded for 2006. In 2005, we recognized a non-cash impairment expense of $580,000 associated with the Company s investment in its Canadian properties.

General and Administrative Expenses. General and administrative expenses in 2006 increased by $347,000, or 18%, from 2005. The increase is due principally to increased Board of Director fees and bonuses resulting from increased meetings, and increased franchise taxes, specifically in Texas, resulting from higher revenues. In September 2006, the Compensation Committee awarded a non-employee director bonus of $25,000 to each of the three non-employee directors for the extraordinary amount of time and effort expended by the non-employee directors during fiscal 2006. In addition, the Compensation Committee revised non-employee director meeting

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compensation and annual retainer policies. The additional 2006 costs associated with the recognition of the bonuses and the revised compensation and annual retainer policies were recorded in the fourth quarter 2006, which resulted in higher costs for the fourth quarter as compared to previous quarters for 2006. Based on a per unit of production basis, general and administrative costs decreased from $9.19 per Mcfe in 2005 to $2.49 per Mcfe in 2006 due to higher production volumes.

Interest Expense. During 2006 and 2005, we recorded interest expense of $371,000 and $343,000, 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). The Company elected to pay accrued interest on the convertible notes of approximately $352,000 and $335,000 for 2006 and 2005, respectively, by increasing the outstanding balance of the Convertible Notes.

Interest Income. We recorded $245,000 and $93,000 in interest income for 2006 and 2005, respectively. Interest income increased in 2006 due to higher average cash balances resulting principally from proceeds received from a private placement of our common stock in October 2005.

The twelve months ended August 31, 2005 (2005) compared with the twelve months ended August 31, 2004 (2004)

					Increase (Decrease)			
		2005		**2004**		**Amount**		**Percent**
		($ in thousands, except for per unit prices and costs)						
Operating Results:								
Revenues								
Gas production revenues	$	2,957	$	334	$	2,623		785%
Oil production & PP revenues		3,145		529		2,616		495%
Total revenues	$	6,102	$	863	$	5,239		607%
Operating Expenses								
Lease operating expense (including production taxes, gathering, transportation)	$	1,104	$	335	$	769		229%
Net profits expense		1,343		0		1,343		
Depletion, depreciation, amortization and accretion		893		273		620		227%
Impairment of oil and gas properties		580		0		580		
General and administrative		1,909		1,324		585		44%
Total operating expenses	$	5,829	$	1,933	$	3,896		202%
Interest expense	$	343	$	327	$	16		5%
Production Data:								
Natural gas (Mcf)		392,067		60,285		331,782		551%
Oil and NGLs (Bbls)		62,284		13,973		48,311		346%
Combined volumes (Mcfe)		765,771		144,123		621,648		432%
Daily combined volumes (Mcfe/d)		2,098		395		1703		431%
Average Prices:								
Natural gas (per Mcf)	$	7.54	$	5.54	$	2.00		36%
Oil and NGLs (per Bbl)		50.49		37.88		12.61		33%
Combined (per Mcfe)		7.97		5.99		1.98		33%

Average Costs (per Mcfe):						
Lease operating expense	$	1.44	$	2.33	$	(0.89)	(38%)
Net profit expense		1.75		0.00		1.75	
Depletion, depreciation, amortization and accretion		1.13		1.20		(0.07)	(6%)
General and administrative		2.49		9.19		(6.70)	(73%)
Interest expense		0.45		2.27		(1.82)	(80%)

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Operations during the fiscal year ended August 31, 2005 resulted in net income of approximately $12,000 compared to a net loss of approximately $1.4 million for the fiscal year ended August 31, 2004. The increase in net income is primarily attributed to income from the producing properties purchased from Venus in May 2004.

Oil and Gas Revenues. During the year ended August 31, 2005, we recorded approximately $6.1 million in total oil and gas revenues compared with approximately $863,000 for the same period in 2004. Natural gas revenues increased to $3.0 million from the sale of 392,067 Mcf of natural gas at an average price of $7.54 per Mcf in 2005 compared with revenues of $334,000 from the sale of 60,285 Mcf of natural gas at an average price of $5.54 per Mcf in 2004. Average natural gas prices for 2005 increased 36% over 2004 average prices. Oil and hydrocarbon liquids revenues for 2005 and 2004 were $3.1 million and $529,000, respectively, from the sale of 62,284 and 13,973 Bbls of oil and hydrocarbon liquids, respectively. Average oil prices increased 33% from $37.88 in 2004 to $50.49 in 2005. The increase in oil and gas revenues and production is principally attributed to new revenues and production from two wells that reached payout during 2005, increased prices and a full year of revenue and production from properties acquired from Venus in May 2004 compared with only four months of revenue and production from the same properties in 2004. During 2005, the Company commenced receiving its net revenue interest proceeds from the Sun Fee GU #1-ST well and the Maness #1 well, located in Texas, after the wells reached payout during the fiscal year 2005. The oil and gas revenues from these wells approximate 55% of total oil and gas revenues for 2005. Revenues from these wells are subject to a net profits expense.

Lease Operating Expenses. Lease operating expenses increased from $335,000 in 2004 to approximately $1.1 million in 2005. The increase is attributed to new wells added and a full year of lease operating expenses on properties acquired from Venus compared with only four months in 2004.

Net Profits Expense. During 2005, two wells, the Sun Fee GU #1-ST and the Maness #1, reached payout and we commenced receiving revenues and incurring operating expenses on these wells. These wells are subject to a net profits expense of 50% of revenues net of capital and operating expenses incurred.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion and amortization expense increased to $894,000 in 2005 from $273,000 in 2004. The increase was primarily attributable to depletion expense of $860,000 associated with increased production volumes from properties acquired from Venus in May 2004. We recorded $8,000 and $13,000 in depreciation expense associated with capitalized office furniture and equipment during 2005 and 2004, respectively. Depreciation of Asset Retirement Obligation assets for the years ended August 31, 2005 and 2004 was $0 and $114,000, respectively. We recorded $25,000 and $100,000, respectively, for the years ended August 31, 2005 and August 31, 2004, of accretion of the unamortized discount of the Asset Retirement Obligation liability. The accretion expense for 2004 was attributable to the properties acquired from Venus in May 2004. For further discussion of the Asset Retirement Obligation, see Note 4 to the Financial Statements included in this Form 10-KSB.

Impairment and Abandonments. We recognized a non-cash impairment expense of $580,000 associated with the Company s investment in its Canadian properties. We recorded no impairment expense for the year ended August 31, 2004

General and Administrative Expenses. General and administrative expenses in 2005 were approximately $1.9 million compared to approximately $1.3 million in 2004. The 44% increase is due principally to higher personnel costs, legal and auditing expenses and contract services. The addition of staff and related general and administrative expenses to manage the Venus properties acquired in May 2004 was the primary factor contributing to the increases.

Interest Expense. During 2005, we recorded interest expense of $343,000 compared to $327,000 in 2004. The interest expense for each year is associated with the May 24, 2002 sale of outstanding convertible notes due on May 24, 2009. The Company elected to add $335,000 and $319,000 of accrued interest to the balance of the debt for the years ended

August 31, 2005 and August 31, 2004, respectively. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our August 31, 2005 and 2004 balance sheets.

Interest Income. We recorded $93,000 and $28,000 in interest income for the years ended August 31, 2005 and 2004, respectively. Interest income increased in 2005 due to higher average cash balances for the majority of 2005 due principally to funds received from a private placement of our common stock in May 2004.

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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, including the following: the amount and timing of actual production; 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 incurred which are directly related to oil and gas exploration and development 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.

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. The Company uses the sales method to account for gas imbalances. Oil and gas sold is not significantly different from the Company s product entitlement. Gas imbalances at August 31, 2006 and 2005 were not significant.

Recent Accounting Pronouncements

In December 2004, the Financial Accounting Standards Board (FSAB) issued its final standard on accounting for employee stock options, SFAS No. 123 (Revised 2004), *Share-Based Payment* (SFAS 123 (R)). SFAS 123 (R) replaces SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and supersedes APB 25, *Accounting for Stock Issued to Employees*. SFAS 123 (R) 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. The pro forma disclosures previously permitted under SFAS 123 will no longer be an alternative to financial statement recognition. For entities that file as a small business issuer, such as PYR Energy Corporation, SFAS 123 (R) is effective for all awards granted, modified, repurchased or cancelled after, and to unvested portions of previously issued and outstanding awards vesting for annual periods beginning after December 15, 2005, which for us will be the first quarter of fiscal 2007. We are currently evaluating the effect of adopting SFAS 123 (R) on our financial position and results of operations. We currently estimate the adoption of SFAS 123 (R) will result in expenses in amounts that are similar to the current pro forma disclosures under SFAS 123.

In March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset retirement obligation , as used in SFAS 143, *Accounting for Asset Retirement Obligations,* refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. However, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing or method of settlement. FIN 47 requires that the uncertainty about the timing or method of settlement of a conditional asset retirement obligation be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption of FIN 47 had no effect on our financial position or results of operations for the fiscal year ended August 31, 2006.

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.

ITEM 7. ***FINANCIAL STATEMENTS***

The Consolidated Financial Statements and schedules that constitute Item 7 are attached at the end of this Annual Report on Form 10-KSB. An index to these Financial Statements and schedules is also included in Item 14(a) of this Annual Report on Form 10-KSB.

ITEM 8. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

None.

ITEM 8A. ***CONTROLS AND PROCEDURES***

As of the end of the period covered by this report, the Company conducted an evaluation of the Company s disclosure controls and procedures (as defined in Rules 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act)). Based on this evaluation, the Company concluded that, subject to the limitations described below, the Company s disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in annual reports that it files under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in Securities and Exchange Commission rules and forms. There was no change in the Company s internal controls over financial reporting during the Company s most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting period.

ITEM 8B. ***OTHER INFORMATION***

Not applicable.

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PART III

ITEM 9. *DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS; COMPLIANCE WITH SECTION 16(a) OF THE EXCHANGE ACT*

The directors and executive officers of the Company, their respective positions and ages, and the year in which each director was first elected, are set forth in the following table. Each director has been elected to hold office until the next annual meeting of stockholders and thereafter until his successor is elected and has qualified. Additional information concerning each of these individuals follows the table.

Name	Age	Position with the Company	Director Since
Kenneth R Berry, Jr.	54	Chief Executive Officer and President	
David Kilpatrick	56	Chairman of the Board	2002
Bryce W. Rhodes	53	Director	1999
Dennis M. Swenson	71	Director	2004
Jane M. Richards	58	Chief Financial Officer	
Tucker L. Franciscus	38	Vice President of Strategic Development and Corporate Secretary	

Kenneth R. Berry, Jr. has served as our Chief Executive Officer since July 25, 2006. Previously he served as Vice President of land since August 1999, and Corporate Secretary since November 2005. From October 1997 to August 1999, Mr. Berry served as our land manager. In addition to his duties as Chief Executive Officer, Mr. Berry is responsible for the management of all land issues including leasing and permitting. Prior to joining the Company, Mr. Berry served as the managing land consultant for Swift Energy Company in the Rocky Mountain region. Mr. Berry began his career in the land department with Tenneco Oil Company after earning a B.A. degree in Petroleum Land Management at the University of Texas Austin.

David B. Kilpatrick has been a Director of the Company since June, 2002 and was appointed as Chairman of the Board in November 2005. He also serves on the Compensation Committee and Audit Committee of the Company. Mr. Kilpatrick is currently President of Kilpatrick Energy Group, which provides strategic management consulting services to the oil and gas industry. He currently serves as a Director of the publicly traded Cheniere Energy and Whittier Energy companies as well as privately held Ensyn Petroleum International, Ltd. Prior to the 1998 merger with Texaco, he was President and Chief Operating Officer of Monterey Resources, Inc., the largest independent oil and gas producer in California. Mr. Kilpatrick has served as President of the California Independent Petroleum Association and is a member of its Board of Directors and also serves as a Director of the Independent Oil Producers Agency. He earned a Bachelor of Science degree in Petroleum Engineering from the University of Southern California and a Bachelor s Degree in Geology and Physics from Whittier College.

Bryce W. Rhodes has been a Director of the Company since April 1999, when he was nominated and elected to the Board in connection with the sale by the Company of convertible promissory notes issued in a private placement transaction in October and November 1998 and serves as the Compensation Committee Chairman and is a member of the Audit Committee. From 1996 until September 2003, Mr. Rhodes served as President and CEO of Whittier Energy Company (WEC), an oil and gas investment company. In September 2003, WEC merged with Olympic Resources, Inc. and Mr. Rhodes was appointed as President and Chief Executive Officer. Mr. Rhodes served as Investment

Manager of WEC from 1990 until 1996. Mr. Rhodes received B.A. degrees in Geology and Biology from the University of California, Santa Cruz, in 1976 and an MBA degree from Stanford University in 1979.

Dennis M. Swenson joined as a Director in October 2004, and serves as the Audit Committee Chairman and a member of the Compensation Committee. From 1992 through 1995, Mr. Swenson was an independent consultant. Mr. Swenson was Executive Vice President, Chief Financial Officer, Secretary and Treasurer, of StarTek, Inc., a NYSE traded company with headquarters in Denver, Colorado, from 1996 through retirement in 2001. Mr. Swenson was employed at Ernst & Young in Denver from 1960 to 1973, and was a partner at Ernst & Young from 1973 to

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1991. He has a Bachelor s Degree in Accounting from Brigham Young University and an MBA Degree from the University of Denver.

Jane M. Richards has served as Chief Financial Officer since July 2006 and as Controller and Chief Accounting Officer since April 2005. Ms. Richards responsibilities include managing the financial reporting for the Company, internal controls and cash management. Ms. Richards has managed financial and accounting reporting in the oil and gas exploration industry for over 20 years. Prior to joining PYR, Ms. Richards served in various financial management positions for Tipperary Corporation, Williams Companies and Barrett Resources Corporation. Mrs. Richards received a B.A. degree in Accounting from the Daniels College of Business at the University of Denver.

Tucker L. Franciscus, Vice President of Strategic Development, joined PYR in September 2004. Prior to joining the Company, Mr. Franciscus was with Stifel Nicolaus & Company, where he oversaw their Investment Banking Energy Group practice between 2001 and 2004. Mr. Franciscus was responsible for mergers and acquisitions, equity and debt offerings, and private placements for all of Stifel s energy clients. Prior to working at Stifel, Mr. Franciscus was the senior associate and manager for the Global Energy Group at J.P. Morgan in New York and an associate in the Deutsche Banc BT Wolfensohn Mergers & Acquisitions Group. Mr. Franciscus has executed equity, debt, mergers and acquisitions and other financing transactions in various industries including defense, energy, media and telecom. For five years preceding his banking experience, Mr. Franciscus worked in various marketing and finance positions in the oil and gas sector, including Synder Oil and KN Energy (Interenergy). Additionally, he was a commissioned Infantry Officer in the U.S. Army and continues to serve in the reserves. During the 2006 fiscal year, he was recalled to active duty for three months. Mr. Franciscus has an MBA from the Daniels College of Business at the University of Denver and a Bachelor of Arts from Ohio Wesleyan University.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934, as amended (the Exchange Act), requires the Company s directors, executive officers and holders of more than 10% of the Company s common stock to file with the Securities and Exchange Commission initial reports of ownership and reports of changes in ownership of common stock and other equity securities of the Company. Except as set forth below, the Company believes that during the year ended August 31, 2006, its officers, directors and holders of more than 10% of the Company s common stock complied with all Section 16(a) filing requirements. In making these statements, the Company has relied solely upon its review of copies of the Section 16(a) reports filed for the fiscal year ended August 31, 2006 on behalf of the Company s directors, officers and holders of more than 10% of the Company s common stock. Based upon this review, Mr. Franciscus and Messrs. Berry and Singdahlsen inadvertently filed his Form 4 delinquently on March 15, 2006 relating to his receipt of 25,000 options to purchase shares of common stock granted on November 2, 2005 and November 23, 2005, respectively. In addition, each of Messrs. Kilpatrick, Rhodes and Swenson inadvertently filed his Form 4 delinquently on March 30, 2006 relating to his receipt of 15,000 options to purchase shares of our common stock granted on November 23, 2005.

Employee Code of Conduct and Code of Ethics and Reporting of Accounting Concerns

The Company has adopted an Employee Code of Conduct (the Code of Conduct). We require all employees to adhere to the Code of Conduct in addressing legal and ethical issues encountered in conducting their work. The Code of Conduct requires that our employees avoid conflicts of interest, comply with all laws and other legal requirements, conduct business in an honest and ethical manner and otherwise act with integrity and in the Company s best interest.

The Company also has adopted a Code of Ethics for our Chief Executive Officer, our Chief Financial Officer, our Controller and all other financial officers and executives. This Code of Ethics supplements our Code of Conduct and is intended to promote honest and ethical conduct, full and accurate reporting, and compliance with laws as well as other matters. The Code of Conduct and Code of Ethics are filed with the SEC.

Further, the Audit Committee of the Board of Directors has established whistle-blower procedures, which provide a process for the confidential and anonymous submission, receipt, retention and treatment of complaints

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regarding accounting, internal accounting controls or auditing matters. These procedures provide substantial protections to employees who report company misconduct.

Audit Committee Financial Expert

The Company s Board of Directors has determined that Mr. Dennis M. Swenson is the Company s audit committee financial expert.

Identification of Audit Committee

The Board of Directors currently has an Audit Committee consisting of Messrs. Swenson (Chairman), Kilpatrick and Rhodes. The Audit Committee is responsible for the selection and retention of our independent auditors, reviews the scope of the audit functions of the independent auditor, and reviews audit reports rendered by our independent auditors. The Audit Committee oversees the Company s financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for the financial statements, accounting policies and procedures, and the reporting process, including the systems of internal controls. In fulfilling its oversight responsibilities, the Committee reviewed and discussed with management the audited financial statements in this Annual Report on Form 10-KSB for the year ended August 31, 2006 and the unaudited financial statements included in the Quarterly Reports on Form 10-Q for the first three quarters of the fiscal year ended August 31, 2006.

ITEM 10. ***EXECUTIVE COMPENSATION***

Summary Compensation Table

The following table sets forth the compensation for the fiscal years ended August 31, 2006, 2005 and 2004 of our Chief Executive Officer, Chief Financial Officer and Vice President, our most highly compensated officers serving as of August 31, 2006.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name and Principal Position	**Fiscal Year**	**Salary ($)(1)**	**Bonus ($)**	**Other Annual Compensation ($)(3)**	**Restricted Stock Awards ($)**	**Securities Underlying Options (#)**	**LTIP Payouts ($)(3)**	**All Other Compensation ($)**
Kenneth R. Berry Jr.	2006	$ 121,000				175,000		
Chief Executive Officer	2005	$ 108,000						
	2004	$ 93,150				135,000		
Jane M. Richards	2006	$ 104,000				85,000		
Chief Financial Officer	2005	$ 38,000				90,000		
	2004							
Tucker L. Franciscus	2006	$ 89,000				25,000		
Vice President	2005	$ 120,000				150,000		
	2004							
D. Scott Singdahlsen(4)	2006	$ 175,000				25,000		
	2005	$ 175,000				200,000		

2004	$	175,000

(1) The dollar value of base salary (cash and non-cash) received during the year indicated.

(2) During the period covered by the Summary Compensation Table, we did not pay any other annual compensation not properly categorized as salary or bonus, including perquisites and other personal benefits, securities or property.

(3) We do not have in effect any plan that is intended to serve as incentive for performance to occur over a period longer than one fiscal year except for our 1997 and 2000 Stock Option Plans and our 2006 Stock Incentive Plan.

(4) Mr. Singdahlsen was the Company s Chief Executive Officer, Chief Financial Officer and President through July 25, 2006, which was the effective date of his resignation from these positions. Mr. Singdahlsen remains an

employee of the Company, and as a result his compensation disclosed above includes both compensation as Chief Executive Officer, Chief Financial Officer and President through July 25, 2006 and compensation as an employee from July 25, 2006 through August 31, 2006.

Aggregated Option Exercises And Fiscal Year-End Option Value Table

The following table provides certain summary information concerning stock option exercises during the fiscal year ended August 31, 2006 by the named executive officers and the value of unexercised stock options held by the named executive officers as of August 31, 2006.

Aggregated Option Exercises in last Fiscal Year and Year-End Option Values(1)

Name	Shares Acquired on Exercise(2)	Value Realized ($)(3)	Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)(4)		Value of Unexercised In-the-Money Options at Fiscal Year-End ($)(5)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Kenneth R. Berry , Jr.			397,500	115,000	158,300	1,950
Jane M. Richards			75,000	100,000		
Tucker L. Franciscus			75,000	100,000	5,500	11,000

(1) No stock appreciation rights are held by any of the named executive officers.

(2) The number of shares received upon exercise of options during the year ended August 31, 2006.

(3) With respect to options exercised during the year ended August 31, 2006, the dollar value of the difference between the option exercise price and the market value of the option shares purchased on the date of the exercise of the options.

(4) The total number of unexercised options held as of August 31, 2006, separated between those options that were exercisable and those options that were not exercisable on that date.

(5) For all unexercised options held as of August 31, 2006, the aggregate dollar value of the excess of the market value of the stock underlying those options over the exercise price of those unexercised options. These values are shown separately for those options that were exercisable and those options that were not yet exercisable on August 31, 2006 based on the closing sale price of our common stock on that date, which was $1.05 per share.

Employee Retirement Plans, Long-Term Incentive Plans and Pension Plans

Excluding the Company s stock option plans, we do not have any long-term incentive plan to serve as incentive for performance to occur over a period longer than one fiscal year.

1997 Stock Option Plan

In August 1997, our 1997 Stock Option Plan (the 1997 Plan) was adopted by the Board of Directors and subsequently approved by the stockholders. Pursuant to the 1997 Plan, we may grant options to purchase an aggregate of 1,000,000 shares of common stock to key employees, directors, and other persons who have contributed or are contributing to our success. The options granted pursuant to the 1997 Plan may be either incentive options qualifying for beneficial tax treatment for the recipient or they may be nonqualified options. The 1997 Plan may be administered by the Board of Directors or by an option committee. Administration of the 1997 Plan includes determination of the terms of options granted under the 1997 Plan. At August 31, 2006, options to purchase 490,000 shares were outstanding under the Plan and 226,500 options were available to be granted under the 1997 Plan.

2000 Stock Option Plan

In March 1999, our 2000 Stock Option Plan (the 2000 Plan) was adopted by the Board of Directors and subsequently approved by the stockholders. Pursuant to the 2000 Plan, we may grant options to purchase shares of our common stock to key employees, directors, and other persons who have contributed or are contributing to our success. We initially could grant options to purchase up to 500,000 shares pursuant to the 2000 Plan. In June 2001, our stockholders approved an amendment which allows us to grant options to purchase up to 1,500,000 shares pursuant to the 2000 Plan. In June 2004, our stockholders approved an amendment to increase from 1,500,000 to 2,250,000 the number of shares of common stock issuable pursuant to options granted under the 2000 Plan. The options granted pursuant to the 2000 Plan may be either incentive options qualifying for beneficial tax treatment for the recipient or non-qualified options. The 2000 Plan may be administered by the Board of Directors or by an option committee. Administration of the 2000 Plan includes determination of the terms of options granted under the 2000 Plan. As of August 31, 2006, options to purchase 1,631,750 shares were outstanding under the 2000 Plan and 412,750 options were available to be granted pursuant to the 2000 Plan.

2006 Stock Incentive Plan

In April 2006, our 2006 Stock Incentive Plan (the 2006 Plan) was adopted by the Board of Directors and subsequently approved by the stockholders in June 2006. Pursuant to the 2006 Plan, we may grant 4,000,000 options to purchase shares of our common stock, restricted stock and restricted stock units to key employees, directors, and other persons who have contributed or are contributing to our success. The options granted pursuant to the 2006 Plan may be either incentive options qualifying for beneficial tax treatment for the recipient or non-qualified options. The 2006 Plan may be administered by the Company s Compensation Committee. Administration of the 2006 Plan includes determination of the terms of options, restricted stock and restricted stock units granted under the 2006 Plan. As of August 31, 2006, options to purchase 210,000 shares were outstanding under the 2006 Plan and 3,790,000 options were available to be granted pursuant to the 2006 Plan.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee is made up of three directors: Messrs. Swenson, Kilpatrick and Rhodes. None of the members of the Committee have been executive officers of the Company. In addition, no member of the Committee is, or was during the fiscal year ended August 31, 2006, an executive officer of another company whose board of directors has a comparable committee on which one of the Company s executive officers serves.

Employment Contracts and Termination of Employment and Change-In-Control Arrangements

We have only one employment agreement, which is with D. Scott Singdahlsen, our former chief executive officer. The agreement, effective August 1, 2006, provides for a base salary of $14,583.33 per month beginning August 1, 2006 through January 31, 2007 and $12,000 per month beginning February 1, 2007 plus the opportunity to participate in project overrides and certain benefits made available to the Company s employees. The agreement expires on July 31, 2007, but may be extended for up to three additional periods of one-year each if mutually agreed.

We currently have no compensatory plan or arrangement that results or will result from the resignation, retirement, or any other termination of an executive officer s employment or from a change-in-control or a change in an executive officer s responsibilities following a change-in-control, except that each of the 1997, 2000 and 2006 Plans provide for vesting of all outstanding options in the event of the occurrence of a change-in-control.

ITEM 11. ***SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS***

Stock Ownership of Directors and Principal Stockholders

As of November 15, 2006, there were 37,993,259 shares of common stock outstanding. The following table sets forth certain information as of that date with respect to the beneficial ownership of common stock by each

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director and nominee for director, by all executive officers and directors as a group, and by each other person known by us to be the beneficial owner of more than five percent of our outstanding shares of common stock:

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned(1)	Percentage of Shares Outstanding
Kenneth R. Berry, Jr. 1675 Broadway, Suite 2450 Denver, Colorado 80202	570,365(2)	1.5%
Bryce W. Rhodes c/o Whittier Energy Company 7770 El Camino Real Carlsbad, CA 92009	175,583(3)	*
David B. Kilpatrick 9105 St. Cloud Lane Bakersfield, CA 93311	98,169(4)	*
Dennis M. Swenson 5360 Lakeshore Drive Littleton, CO 80123	78,169(5)	*
Tucker L. Franciscus 1675 Broadway, Suite 2450 Denver, Colorado 80202	125,000(6)	*
Jane M. Richards 1675 Broadway, Suite 2450 Denver, Colorado 80202	75,000(7)	*
All Executive Officers and Directors as a group (six persons)	1,142,286(2)(3)(4)(5)(6)(7)	3.0%
D. Scott Singdahlsen 1675 Broadway, Suite 2450 Denver, Colorado 80202	2,151,750(8)	5.6%
Victory Oil Company 222 West Sixth Street, Suite 1010 San Pedro, California 90731	2,773,204(9)	7.3%
Eastbourne Capital Management, L.L.C. 1101 Fifth Avenue, Suite 160 San Rafael, CA 94901	3,634,000(10)	9.6%

(*) Less than one percent.

(1) Beneficial ownership is defined in the regulations promulgated by the U.S. Securities and Exchange Commission as having or sharing, directly or indirectly (1) voting power, which includes the power to vote or to direct the voting, or (2) investment power, which includes the power to dispose or to direct the disposition of shares of the common stock of an issuer. The definition of beneficial ownership includes shares underlying options or warrants to purchase common stock, or other securities convertible into common stock, that currently are exercisable or convertible or that will become exercisable or convertible within 60 days. Unless otherwise indicated, the beneficial owner has sole voting and investment power.

(2) Includes the following securities held directly or indirectly by Kenneth R. Berry, Jr.: an aggregate of 172,865 shares owned by various entities, IRAs, and trusts with which Mr. Berry, or his spouse or minor daughter, is associated; and options to purchase 397,500 shares of common stock at exercise prices ranging from $.29 to $1.65 per share that currently are exercisable or that will become exercisable within the next 60 days. Does not include options to purchase an additional 15,000 shares at $0.92 until August 25, 2009 that become exercisable in fiscal 2007 and options to purchase 100,000 shares at $1.12 until July 25, 2011 of which 50,000 share increments become exercisable in July 2007 and 2008, respectively.

(3) Includes 13,000 shares of common stock owned by Mr. Rhodes and 64,414 shares of common stock owned by Adventure Seekers Travel, Inc. Adventure Seekers is owned by Mr. Rhodes wife and Mr. Rhodes is the

President of Adventure Seekers. Also includes options to purchase 20,000 shares at $1.65 per share until April 11, 2007, options to purchase 50,000 shares at $1.15 per share until October 14, 2009, options to purchase 15,000 shares at $1.34 per share until November 22, 2010 and options to purchase 13,169 shares at $0.97 per share until October 10, 2011 that are exercisable or will become exercisable within the next 60 days. Does not include options to purchase an additional 13,169 shares at $0.97 per share until October 10, 2011 of which 6,585 and 6,584 become exercisable on February 28, 2007 and May 31, 2007, respectively. Excludes 171,625 shares that are held by Whittier Energy Company. Mr. Rhodes is a President and CEO of Whittier Energy Company. Mr. Rhodes disclaims beneficial ownership of the shares beneficially owned by Whittier Energy Company.

(4) Includes options to purchase 20,000 shares at $1.72 per share until June 4, 2007, options to purchase 50,000 shares at $1.15 per share until October 14, 2009, options to purchase 15,000 shares at $1.34 per share until November 22, 2010 and options to purchase 13,169 shares at $0.97 per share until October 10, 2011 that are exercisable or will become exercisable within the next 60 days. Does not include options to purchase an additional 13,169 shares at $0.97 per share until October 10, 2011 of which 6,585 and 6,584 become exercisable on February 28, 2007 and May 31, 2007, respectively.

(5) Includes options to purchase 50,000 shares at $1.24 per share until October 1, 2009, options to purchase 15,000 shares at $1.34 per share until November 22, 2010 and options to purchase 13,169 shares at $0.97 per share until October 10, 2011 that are exercisable or will become exercisable within the next 60 days. Does not include options to purchase an additional 13,169 shares at $0.97 per share until October 10, 2011 of which 6,585 and 6,584 become exercisable on February 28, 2007 and May 31, 2007, respectively.

(6) includes options to purchase 100,000 shares at $.94 share until September 1, 2009 and options to purchase 25,000 shares at $1.34 per share until November 1, 2010. Does not include options to purchase an additional 50,000 shares at $0.94 share until September 1, 2009 which become exercisable on September 1, 2007.

(7) Includes options to purchase 30,000 shares at $1.46 until April 15, 2010, options to purchase 25,000 shares at $1.34 until November 22, 2010 and options to purchase 20,000 at $1.12 until July 25, 2011. Does not include options to purchase an additional 40,000 shares at $1.12 of which 20,000 share increments will become exercisable on July 26, 2007 and 2008, respectively.

(8) The shares shown for Mr. Singdahlsen include 200,000 shares owned by Mr. Singdahlsen s two minor children. Also includes options to purchase 15,000 shares at $1.82 per share until April 12, 2007, options to purchase 200,000 shares at $0.29 per share until February 4, 2010, options to purchase 81,750 shares at $1.30 per share until February 4, 2010, options to purchase 80,000 shares at $0.96 per share until November 17, 2014 and options to purchase 25,000 shares at $1.34 per share until November 22, 2010.

(9) Based on the information provided by shareholder.

(10) The shares reflected include shares beneficially owned by Eastbourne Capital Management, L.L.C., a registered investment adviser, Richard Jon Barry, Manager of Eastbourne and the following companies to which Eastbourne is investment adviser: Black Bear Offshore Master Fund Limited, a Cayman Island exempted company, Black Bear Fund I, L.P. and Black Bear Fund II, LLC. Not included are equivalent shares of common stock underlying $7,309,500 of convertible notes held by Black Bear Offshore Master Fund Limited, Black Bear Fund I, L.P. and Black Bear Fund II, LLC.

ITEM 12. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS*

On May 24, 2002, certain investment entities managed by Eastbourne Capital Management, LLC purchased $6 million of convertible notes from the Company. The notes provide for semi-annual interest payments at an annual rate of 4.99% and are convertible into common stock at the rate of $1.30 per share. At the time of the transaction, these entities had aggregate ownership in PYR Energy Corporation of approximately 15%. Concurrent with the sale, we agreed to add Messrs. Eric Sippel and Borden Putnam, of Eastbourne, to our Board of Directors. Messrs. Sippel and Putnam resigned from the board in August 2003, although Eastbourne still has the right to designate two individuals to serve on the Board.

As more fully described in the Form 8-K filed with the SEC on October 26, 2005, in mid-October 2005, the Company completed a private equity placement consisting of the sale of 6.275 million shares of common stock, priced at $1.30 per share, to a group of institutional and accredited individual investors and issued warrants to purchase 52,500 shares of common stock at a price of $1.30 per share to a financial advisory company as partial payment for services rendered. Pursuant to the terms of the private placement, the Company filed a registration statement covering the resale of these shares. Kenneth R. Berry, Jr., who is now our Chief Executive Officer (and at the time of purchase was our Vice President of Land), purchased beneficial ownership of shares of our common stock in connection with this private placement, which occurred on October 3, 2005, as follows. The Kenneth R. Berry, Jr. and Leslie A. Berry Trust (the Trust) purchased 20,000 shares of common stock in the private placement. Mr. Berry is a trustee and beneficiary of the trust. Estancia Petroleum Corporation (Estancia) purchased 50,000 shares of common stock in the private placement. Mr. Berry owns all the outstanding equity interests in Estancia Corporation. The foregoing purchases were made at the same purchase price as all the other purchasers in the private placement and account for 1.1% ($91,000) of the total $8,157,000 private placement offering. The shares were subscribed for pursuant to two separate Subscription Agreements, each executed on October 3, 2005 by the Trust and Estancia, respectively. Based on the closing price of our stock on October 3, 2005, the aggregate dollar discount from that market price that was received by the Trust and Estancia in connection with the purchase of their shares was $53,900, or $0.77 per share. Mr. Berry was not involved in the structure or negotiation of the terms of the private placement, nor did he commit to purchase any shares pursuant to the private placement until after: (1) the price per share had been negotiated between the Company and an unrelated third party, and (ii) the private placement had commenced. Our Audit Committee had approved Mr. Berry s participation in the private placement in a meeting held on November 2, 2005. On June 22, 2006, our shareholders ratified the issuance of the shares purchased as part of the private placement by the Trust and Estancia as described above.

During the fiscal year ended August 31, 2006, there were no other transactions between the Company and its directors, executive officers or known holders of greater than five percent of the Company s common stock in which the amount involved exceeded $60,000 and in which any of the foregoing persons had or will have a material interest.

ITEM 13. *EXHIBITS*

Exhibit Index

Number	Description
3.1*	Articles of Incorporation, filed with the Maryland Secretary of State on June 18, 2001(1)
3.2*	Articles of Merger, filed with the Maryland Secretary of State on July 3, 2001(1)
3.3*	Bylaws(1)
4.1*	Specimen Common Stock Certificate(2)
4.2*	Subscription and Registration Rights Agreement between Wellington parties and the Company, September 2005(3)
21	List of the Company s Subsidiaries
23.1	Consent of HEIN & Associates LLP.
23.2	Consent of Ryder Scott Company
31.1	Certification of Chief Executive Officer
31.2	Certification of Chief Financial Officer
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Executive Officer
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Financial Officer

* Previously filed.

(1) Incorporated by reference from the Company s Form 10-KSB for the year ended August 31, 2001.

(2) Incorporated by reference from the Company s Form 10-KSB/A1 for the year ended August 31, 1997.

(3) Incorporated by reference from the Company s Report on Form 8-K filed on October 8, 2005.

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ITEM 14. *PRINCIPAL ACCOUNTANT FEES AND SERVICES*

Audit Fees

Hein & Associates LLP, the Company s principal accountants, billed the Company approximately $76,000 and $79,000 for the years ended August 31, 2006 and 2005, respectively. Hein s professional services, as of August 31, 2006, included review of financial statements included in the Company s Forms 10-Q, and services provided in connection with regulatory filings.

Audit-Related Fees

For the years ended August 31, 2006 and 2005, Hein & Associates LLP billed the Company approximately $2,000 in each fiscal year for work performed in the preparation of a Form S-3 filed during fiscal 2006 and an 8-K filed during fiscal 2005, respectively.

Tax Fees

There was approximately $3,000 billed by Hein & Associates, LLP for professional services for tax compliance, tax advice, and tax planning for fiscal 2006. No amounts were billed for such services in fiscal 2005.

All Other Fees

For the years ended August 31, 2006 and August 31, 2005, Hein & Associates, LLP did not bill the Company for products and services other than those described above.

Audit Committee Pre-Approval Policies

The audit committee currently does not have any pre-approval policies or procedures concerning services performed by Hein & Associates, LLP. All services performed by Hein & Associates, LLP that are described above were pre-approved by the audit committee.

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SIGNATURES

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

PYR ENERGY CORPORATION

By: /s/ Kenneth R. Berry, Jr.

Kenneth R. Berry, Jr.
Chief Executive Officer

Date: November 22, 2006

By: /s/ Jane M. Richards

Jane M. Richards
Chief Financial Officer and Principal Accounting Officer

Date: November 22, 2006

In accordance with the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signatures	Title	Date
/s/ Kenneth R. Berry, Jr.	Chief Executive Officer	November 22, 2006
Kenneth R. Berry, Jr.		
/s/ Jane M. Richards	Chief Financial Officer	November 22, 2006
Jane M. Richards		
/s/ David Kilpatrick	Chairman of the Board	November 22, 2006
David Kilpatrick		
/s/ Dennis M. Swenson	Director	November 22, 2006
Dennis M. Swenson		
/s/ Bryce W. Rhodes	Director	November 22, 2006
Bryce W. Rhodes		

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PYR ENERGY CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
PYR Energy Corporation
Denver, Colorado

We have audited the consolidated balance sheets of PYR Energy Corporation and subsidiaries as of August 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity and cash flows for the years then ended. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of PYR Energy Corporation and subsidiaries as of August 31, 2006 and 2005, and the results of their operations and their cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

HEIN *& ASSOCIATES LLP*

Denver, Colorado
November 6, 2006

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PYR ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	August 31, 2006	August 31, 2005
	(In thousands, except share and per share data)	
ASSETS		
Current Assets:		
Cash	$ 6,254	$ 2,934
Oil and gas receivables	1,784	1,618
Other receivable	62	124
Prepaid expenses and other assets	64	59
Total current assets	8,164	4,735
Property and Equipment, at cost		
Oil and gas properties under full cost, net	20,421	13,242
Furniture and equipment, net	45	29
	20,466	13,271
Other Assets:		
Deferred financing costs and other assets	29	80
Total Assets	$ 28,659	$ 18,086
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities:		
Accounts payable	$ 321	$ 89
Amounts payable to oil and gas property owners	38	2
Accrued expenses:		
Accrued interest payable	99	94
Accrued net profits payable	231	1,287
Other accrued liabilities	936	282
Asset retirement obligation	907	904
Total current liabilities	2,532	2,658
Long-Term Liabilities:		
Convertible notes	7,310	6,958
Asset retirement obligation	366	293
Total long-term liabilities	7,676	7,251

Commitments And Contingencies (Note 9)		
Stockholders Equity:		
Preferred stock, $.001 par value; authorized 1,000,000 shares; issued and outstanding none		
Common stock, $.001 par value; authorized 75,000,000 shares; issued and outstanding 37,993,259 at 8/31/06 and 31,640,259 shares at 8/31/05	38	32
Capital in excess of par value	51,292	43,294
Accumulated deficit	(32,879)	(35,149)
Total stockholders equity	18,451	8,177
Total Liabilities and Stockholders Equity	$ 28,659	$ 18,086

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

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PYR ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended August 31, 2006	2005
	(In thousands, except per share data)	
Revenues:		
Oil and gas revenues	$ 10,319	$ 6,102
Operating Expenses:		
Lease operating expenses	1,547	721
Production taxes, gathering and transportation	689	383
Net profits expense	829	1,343
Impairment		580
Depreciation, depletion, amortization and accretion	2,616	893
General and administrative	2,256	1,909
Total operating expenses	7,937	5,829
Income From Operations	2,382	273
Other Income (Expense):		
Interest income	245	93
Interest (expense)	(371)	(343)
Other (expense) income	14	(11)
Total other income (expense)	(112)	(261)
Net Income	$ 2,270	$ 12
Net Income Per Common Share -Basic And Diluted	$ 0.06	$ 0.00
Weighted Average Shares Outstanding		
Basic	37,319	31,597
Diluted	37,864	32,290

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

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PYR ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

	Common Stock Shares	Common Stock Amount	Capital in Excess of Par Value	Accumulated Deficit
		(In thousands)		
Balance, September 1, 2004	31,564	$ 32	$ 43,221	$ (35,161)
Exercise of common stock options for cash	76		58	
Issuance of common stock options for director services			15	
Net income				12
Balance, August 31, 2005	31,640	32	43,294	(35,149)
Exercise of common stock options for cash	78		33	
Private Placement sale of common stock, net of offering costs of $196,000	6,275	6	7,955	
Issuance of non-qualifying options			10	
Net income				2,270
Balance, August 31, 2006	37,993	$ 38	$ 51,292	$ (32,879)

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

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PYR ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended August 31, 2006	2005
	(In thousands)	
Operating Activities:		
Net income	$ 2,270	$ 12
Adjustments to reconcile net income to net cash used by operating activities		
Depreciation and amortization	2,593	868
Impairment		580
Amortization of financing costs	3	3
Interest expense converted into debt	352	335
Accretion of asset retirement obligation	22	25
Stock option expense for non-qualifying options issued	10	
Stock options issued for director services		15
Changes in current assets and liabilities (Increase) in accounts receivable	(104)	(1,266)
Decrease (increase) in prepaids and other receivables	(5)	44
Increase in accounts payable	30	4
Increase in amounts payable to oil and gas property owners	36	
Increase in accrued liabilities	284	22
(Decrease) increase in net profits payable	(1,056)	1,287
Other		
Net cash provided by operating activities	4,435	1,929
Investing Activities:		
Cash paid for furniture and equipment	(29)	(10)
Cash paid for oil and gas properties	(9,526)	(5,862)
Proceeds from sale of exploration options		750
Proceeds from sale of oil and gas properties	398	49
Net cash used in investing activities	(9,157)	(5,073)
Financing Activities:		
Proceeds from sale of common stock	8,157	
Proceeds from exercise of options	33	58
Cash paid for offering costs	(178)	(18)
Other	30	
Net cash provided by financing activities	8,042	40
Net (Decrease) Increase In Cash	3,320	(3,104)

Cash, Beginning Of Year		2,934		6,038
Cash, End Of Year	$	6,254	$	2,934
Cash paid for interest and income taxes	$	10	$	
Non-cash financing activities:				
Asset retirement obligation increase	$	54	$	15
Net increase in payables and accrued liabilities for capital expenditures		578		3
Debt issued for interest		351		335

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

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the fiscal years ended August 31, 2005 and 2006

1. Organization And Summary Of Significant Accounting Policies

Organization And Business PYR Energy Corporation (the Company) is an independent oil and gas company primarily engaged in the exploration for, acquisition, development and production of crude oil and natural gas. The Company s current activities are principally conducted in the Rocky Mountains, Texas, and Gulf Coast regions of the United States.

On February 18, 2004, PYR Cumberland LLC, PYR Mallard LLC, and PYR Pintail LLC were formed as wholly owned subsidiaries of PYR Energy Corporation. The purpose of these entities is to own and develop certain assets related to designated individual exploration projects.

Basis Of Presentation The accompanying consolidated financial statements for the years ended August 31, 2006 and 2005 include the Company and its three wholly owned subsidiaries (collectively, the Company , we , us or our). All significant inter-company transactions have been eliminated upon consolidation.

Cash Equivalents For purposes of reporting cash flows, the Company considers as cash equivalents all highly liquid investments with a maturity of three months or less at the time of purchase. On occasion, the Company has cash in banks in excess of federally insured amounts. See Concentration of Risk below.

Receivables And Credit Policies The Company has certain trade receivables consisting of oil and gas sales obligations due under normal trade terms. Management regularly reviews trade receivables and reduces the carrying amount by a valuation allowance that reflects management s best estimate of the amount that may not be collectible.

Oil And Gas Properties The Company utilizes 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. The Company s oil and gas properties are located within the United States and Canada. Properties within these respective countries constitute separate cost centers. 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. A reserve is provided for estimated future costs of site restoration, dismantlement and abandonment activities.

The Company utilizes the full cost accounting method of accounting for oil and gas activities and in 2006 and 2005 had separate cost centers for the United States and Canada. During 2005, the Company recorded a non-cash impairment of $580,000 of its initial oil and gas investment in Canada as the book value of the properties exceeded the estimated fair market value of such properties. The Company decided to limit future expenditures in Canada.

The Company leases non-producing acreage for its exploration and development activities. The cost of these leases is included in unevaluated oil and gas property costs recorded at the lower of cost or fair market value.

Furniture And Equipment Furniture and equipment is recorded at cost. Depreciation of assets is provided by use of the straight-line method over the estimated useful lives of the related assets of three to five years.

PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than oil and gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-oil and gas long-lived assets.

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. The Company has no gas balancing arrangements in place. Oil and gas sold is not significantly different from the Company s product entitlement.

Deferred Financing Costs Costs incurred in connection with the execution of the Company s Convertible Notes have been capitalized and are amortized over the life of the notes.

Income Taxes The Company has adopted the provisions of Statement of Financial Accounting Standards No. 109 (SFAS 109), *Accounting for Income Taxes* issued by the Financial Accounting Standards Board (FASB). SFAS 109 requires recognition of deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

Temporary differences between the time of reporting certain items for financial and tax reporting purposes consist primarily of exploration and development costs on oil and gas properties, and impairment pursuant to the ceiling test limitation.

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.

The Company s financial statements are based on a number of significant estimates, including ability to realize its receivables and deferred tax assets, 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.

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 it may be currently liable. In addition, the Company s oil and gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves, which is considered a significant estimate by the Company, which is 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 the Company s full cost pool.

Net Income Per Share Basic net income per common share is computed based on the weighted average number of common shares outstanding during each period. Diluted net income per common share is computed based on the weighted average number of common shares outstanding plus other dilutive securities such as stock options and warrants.

Share Based Compensation In October 1995, the FASB issued 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 encourages entities to adopt that method of accounting for its stock compensation plans. SFAS 123 allows 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) for annual periods beginning before December 15, 2005.

PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accordingly, for the years ended August 31, 2006 and 2005, the Company has elected to continue to account for its employee stock compensation plans as prescribed under APB 25. Had compensation cost for the Company s 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, the Company s net (loss) and (loss) per share for the years ended August 31, 2006 and 2005 would have been increased to the pro forma amounts indicated below:

	2006	2005
	(In thousands, except per share data)	
Net income:		
As reported	$ 2,270	$ 12
Total compensation cost determined under the fair value base method for all awards	(559)	(331)
Pro forma net income (loss)	$ 1,711	$ (319)
Net pro forma income (loss) per share:		
As reported Basic and Dilutive	$ 0.06	$ (0.00)
Pro forma Basic and Dilutive	$ 0.05	$ (0.01)

See Note 8 with respect to assumptions used. See *Recent Accounting Pronouncements* regarding the adoption of SFAS No. 123(R).

Gas Balancing The Company uses the sales method of accounting for gas balancing of gas production, and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of August 31, 2006, the Company was over-produced by 17 MMcf (unaudited), which represents approximately $98,000 in gas revenues based on an average sales price of $5.78 per equivalent Mcfe

Fair Value The carrying amount reported in the balance sheet for cash, prepaid expenses, accounts payable and accrued liabilities approximates fair value because of the immediate or short-term maturity of these financial instruments.

In May 2002, the Company completed the sale of $6 million, 4.99% convertible promissory notes, due May 2009. The notes are convertible, together with accrued interest, into shares of the Company s common stock at the rate of $1.30 per share, at the option of the holder. The company considers the notes to be stated at fair value due to arms length negotiation of the transaction and the conversion feature.

Concentration Of Risk Financial instruments which potentially subject the Company to concentrations of credit risk consist of cash and receivables. The Company maintains cash accounts at one financial institution. The Company periodically evaluates the credit worthiness of financial institutions, and maintains cash accounts only in large high quality financial institutions, thereby minimizing exposure for deposits in excess of federally insured amounts. The Company believes that credit risk associated cash is remote.

The Company has concentrated its United States exploration and production activities primarily in the Rocky Mountain, Texas and Gulf Coast regions. All significant activities in these segments have been with industry partners.

As of August 31, 2005 and August 31, 2006, there were no reserves associated with the Canadian cost center. The Company s oil and gas prospects in Canada consist of undeveloped properties. During 2005, the Company recorded a non-cash impairment of $580,000 of its initial oil and gas investment in Canada as the book value of these properties exceeded the estimated fair market value of such properties. The Company decided to limit future expenditures in Canada.

PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Customers accounting for 10% or more of gross revenue, all representing purchasers of oil and gas, for the years ended August 31, 2006 and 2005 are as follows:

	2006	2005
Customer A	26%	
Customer B	20%	38%
Customer C	11%	
Customer D		22%
Customer E		10%

Reclassification Certain reclassifications have been made to the 2005 financial statements to conform to 2006 presentation. Such reclassifications had no effect on the net income (loss).

Recent Accounting Pronouncements In December 2004, the FSAB issued its final standard on accounting for employee stock options, SFAS No. 123 (Revised 2004), *Share-Based Payment* (SFAS 123 (R)). SFAS 123 (R) replaces SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and supersedes APB 25, *Accounting for Stock Issued to Employees.* SFAS 123 (R) 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. The pro forma disclosures previously permitted under SFAS 123 will no longer be an alternative to financial statement recognition. For entities that file as a small business issuer, such as PYR Energy Corporation, SFAS 123 (R) is effective for all awards granted, modified, repurchased or cancelled after, and to unvested portions of previously issued and outstanding awards vesting for annual periods beginning after December 15, 2005, which for us will be the first quarter of fiscal 2007. We are currently evaluating the effect of adopting SFAS 123 (R) on our financial position and results of operations. We currently estimate the adoption of SFAS 123 (R) will result in expenses in amounts that are similar to the current pro forma disclosures under SFAS 123.

In March 2005, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47). FIN 47 clarifies that the term conditional asset retirement obligation , as used in SFAS 143, *Accounting for Asset Retirement Obligations,* refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. However, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing or method of settlement. FIN 47 requires that the uncertainty about the timing or method of settlement of a conditional asset retirement obligation be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The adoption of FIN 47 had no effect on our financial position or results of operations for the fiscal year ended August 31, 2006.

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.

2. Acquisition and Divestitures of Properties

In February 2005, the Company acquired additional working and revenue interest in two producing properties and additional interest in undeveloped properties located in Hansford County of the Texas panhandle for a purchase price of approximately $440,000.

PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In December 2005, the Company again acquired additional working and revenue interests in the Hansford project, from multiple private entities for $1.7 million. This acquisition included 1.64 Bcf of proved reserves and 2,265 acres of leasehold. As a result of these acquisitions, the Company owns 100% working interest on a majority of the acreage which includes three producing wells, one of which was drilled and completed in 2006.

The Company sold its interest in certain leasehold acreage located in the School Road prospect in California for approximately $96,000 and sold its interest in approximately 250 acres in the Merganser prospect located in Leon County, Texas for approximately $280,000 in December 2005 and February 2006, respectively.

3. <u>Property and Equipment</u>

<u>Oil and Gas Properties</u> Oil and gas properties at August 31, 2006 and 2005 consisted of the following:

	2006	2005
	(In thousands)	
Oil and gas properties, full cost method		
Unevaluated costs, not subject to amortization		
United States	$ 1,852	$ 5,164
Evaluated costs	47,079	37,767
	48,931	42,931
Less accumulated depreciation, depletion, amortization and impairment	(28,510)	(29,689)
	$ 20,421	$ 13,242

Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Exploration costs include the costs of geological and geophysical activity, and drilling and equipping exploratory wells. The Company reviews and determines the cost basis of drilling prospects on a drilling location basis.

Unevaluated property costs consisting of unproved oil and gas leases (totaling approximately $1.437 million) and exploration costs and exploratory wells in progress (totaling approximately $415,000) as of the end of the year have been excluded from depletable costs pending further evaluation as of August 31, 2006 are as follows (in thousands):

Period Incurred	
2006	$ 1,118
2005	345
2004	348
2003	41
	$ 1,852

For the years ended August 31, 2006 and 2005, the Company did not recognize any impairment expense against the capitalized oil and gas properties in the United States, as determined by the ceiling test performed pursuant to Regulation S-X Rule 4-10(c)(2). For the year ended August 31, 2005, the Company recognized an impairment expense of $580,000 against the capitalized oil and gas properties in Canada.

Depreciation, depletion, and amortization of oil and gas properties for the years ended August 31, 2006 and 2005 was approximately $2.6 million and $860,000, or $2.04 and $1.12 per Mcfe of gas produced, respectively. Depreciation of assets recognized in accordance with the Asset Retirement Obligation calculation is included in these amounts (see below).

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Information relating to the Company s costs incurred in its oil and gas operations during the years ended August 31, 2006 and 2005 is summarized as follows:

	2006	2005
	(In thousands)	
Property acquisition costs	$ 1,714	$ 440
Exploration costs	5,597	5,101
Development costs	2,793	276
	$ 10,104	$ 5,817

Furniture and Equipment Furniture and equipment at August 31, 2006 and 2005 consisted of the following:

	2006	2005
	(In thousands)	
Furniture and equipment	$ 178	$ 149
Less accumulated depreciation	(133)	(120)
	$ 45	$ 29

Depreciation expense associated with capitalized office furniture and equipment during fiscal 2006 and 2005 was $14,000 and $8,000, respectively.

4. Asset Retirement Obligations

In 2001, the FASB issued SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires companies to record the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The liability is capitalized as part of the related long-lived asset s carrying amount. Over time, accretion of the liability is recognized as an operating expense and the capitalized cost is depreciated over the expected useful life of the related asset. The Company s asset retirement obligations relate primarily to the plugging, dismantlement, removal, site reclamation and similar activities of its oil and gas properties.

The following table summarizes activity related to the accounting for asset retirement obligations for the fiscal years ended August 31, 2006 and August 31, 2005:

	2006	2005
	(In thousands)	
Asset retirement obligations, beginning of fiscal year	$ 1,197	$ 1,158
Liabilities incurred	54	19
Liabilities settled		
Accretion of asset retirement obligation including revision of estimates	22	20
Asset retirement obligations, end of fiscal year	1,273	1,197
Less current portion	(907)	(904)
Long-term portion	$ 366	$ 293

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Net Income per Share

The following table sets forth the computation of basic and diluted earning per share (in thousands except per share data):

	Years Ended August 31, 2006	2005
Numerator:		
Net income	$ 2,270	$ 12
Denominator:		
Weighted-average shares outstanding	37,319	31,597
Effect of Dilutive Securities:		
Assumed exercise of dilutive options	545	693
Weighted-average shares and dilutive potential common shares	37,864	32,290
Basic and dilutive income per share	$ 0.06	$ 0.00

6. Convertible Notes Payable

In May 2002, the Company completed the sale of $6 million, 4.99% convertible promissory notes, due May 2009. The notes are convertible, together with accrued interest, into shares of the Company s common stock at the rate of $1.30 per share, at the option of the holder. No beneficial interest has been accrued to the notes, as the conversion price approximates the fair market value of the common shares as of the transaction date. Interest is payable semiannually in May and November.

At the option of the Company, accrued interest can be paid in cash or added to the principal amount of the notes. The Company elected to add accrued interest of approximately $351,000 and $335,000 during fiscal years 2006 and 2005, respectively, to the balance of the notes. As of August 31, 2006 the balance of the notes is approximately $7.3 million.

7. Income Taxes

The Company follows the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. At August 31, 2006, the Company had approximately $42.3 million of net operating losses and $45,000 of statutory depletion carry forward for tax return purposes. These losses expire in varying amounts between 2012 and 2026 and utilization could be limited if the Company experienced a change in control as defined in the Internal Revenue Code.

Due to the net operating loss, no income tax expense was recorded in the consolidated statements of operations.

The effective income tax rate differs from the U.S. Federal statutory income tax rate due to the following:

	Years Ended August 31,	
	2006	**2005**
Federal statutory income tax rate	(34)%	(34)%
Increase in valuation allowance	34%	34%
Effective rate		

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The principal sources of temporary differences resulting in deferred tax assets and tax liabilities at August 31, 2006 and 2005 are as follows:

	2006	2005
	(In thousands)	
Deferred tax assets:		
Asset retirement obligation	$ 472	$ 444
Tax loss carryforward	15,988	15,296
Total deferred tax assets	16,460	15,740
Less valuation allowance	(13,658)	(14,471)
Net deferred tax assets	$ 2,802	$ 1,269
Deferred tax liabilities:		
Property impaired for financial reporting, but capitalized for tax; offset by intangible drilling and other exploration costs capitalized for financial reporting purposes but deducted for tax purposes	(2,802)	(1,269)
Total deferred tax liabilities	$ (2,802)	$ (1,269)
Net deferred taxes	$	$

The valuation allowance decreased by approximately $813,000 in 2006 and increased by $171,000 in 2005.

8. Stockholders Equity:

Preferred Stock In April 1999, the stockholders of the Company approved an amendment to the Certificate of Incorporation pursuant to which the Company was authorized to issue 1,000,000 shares of preferred stock, with a par value of $.001 per share. Such shares of preferred stock may be issued with such preferences and rights as determined by the Board of Directors.

Common Stock In October 2005, the Company completed a private placement in which the Company sold 6.275 million shares of common stock at a price of $1.30 per share to a group of accredited institutional and individual investors and issued warrants to purchase 52,500 shares of common stock at a price of $1.30 per share to a financial advisory company as partial payment for services rendered. We received approximately $8.0 million in net proceeds after deducting related offering expenses. The proceeds received from the private placement were used for general corporate purposes and costs associated with our drilling portfolio. In December 2005, a registration statement that became effective January 2006 was filed to register the re-sale of the securities issued pursuant to this private placement by the investors.

Warrants In October 2005, we issued warrants to purchase 52,500 shares of common stock in partial payment of a commission for financial advisory services performed in connection with a private placement. The warrants have an exercise price of $1.30 per share, expire in five years and were valued at approximately $50,000 based on the Black-Scholes option pricing model.

At August 31, 2006, the status of outstanding warrants is as follows:

Issue Date	**Shares Exercisable**	**Exercise Price**	**Expiration Date**
May 9, 2002	200,000	$ 1.49	May 8, 2007
December 1, 2003	100,000	$ 0.65	December 1, 2006
May 5, 2004	225,000	$ 1.30	May 5, 2009
June 11, 2004	150,000	$ 1.24	June 11, 2009
October 17, 2005	52,500	$ 1.30	October 17, 2010

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At August 31, 2006, the weighted average remaining contractual life of outstanding warrants was 1.4 years.

Stock Options Under two stock option plans and one stock incentive plan, options to purchase common stock may be granted until 2016. Stock options are granted to employees at exercise prices equal to the fair market value of the Company s stock at the dates of grants. Generally, options vest 1/3 each year for a period of three years from grant date and can have a maximum term of up to 10 years. Options are issued to key employees and other persons who contribute to the success of the Company. The Company has reserved 7,250,000 shares of common stock for these plans. At August 31, 2006 and 2005, options to purchase 4,429,250 and 604,250 shares, respectively, were available to be granted pursuant to the stock option plans.

The status of outstanding options granted pursuant to the plans are as follows:

	Number of Shares	Weighted Avg. Exercise Price	Weighted Avg. Fair Value
Options Outstanding August 31, 2004	2,183,834	$ 1.76	
Granted	675,000	$ 1.08	$ .68
Exercised	(75,834)	$ .76	
Expired/forfeited	(548,250)	$ 2.43	
Options Outstanding August 31, 2005	2,234,750	$ 1.41	
Granted	435,000	$ 1.23	$ .89
Exercised	(78,000)	$ .42	
Expired/forfeited	(260,000)	$ 2.83	
Options Outstanding August 31, 2006	2,331,750	$ 1.08	
Exercisable as of August 31, 2006	1,744,752	$ 1.07	

The calculated value of stock options granted under these plans, following calculation methods prescribed by SFAS 123, uses the Black-Scholes stock option pricing model with the following weighted-average assumptions used:

	2006	2005
Expected option life-years	5	7
Risk-free interest rate	4.7 %	3.5 %
Dividend yield	0	0
Weighted average volatility	90.6 %	70.0 %

At August 31, 2006 and 2005, the number of options exercisable was 1,744,752 and 1,213,500 respectively, and the weighted average exercise price of these options was $1.07 and $1.76, respectively.

		Options Outstanding		
Exercise Price		**August 31, 2006**	**Remaining Contractual Life (Years)**	**Options Exercisable at August 31, 2006**
$0.29	$0.46	325,000	3	325,000
$0.47	$0.96	402,000	3	247,002
$0.97	$1.30	1,089,750	4	717,750
$1.31	$1.82	515,000	3	455,000
Total		2,331,750		1,744,752

PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Commitments and Contingencies

Litigation

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), has 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 has no interest, many of which are non-productive. Samson has a large interest in the properties that Samson has 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 had authority to pool PYR s working interest into the unit, 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. Following a brief scheduling conference, the Court has requested that the parties discuss next steps, including (i) resuming the trial schedule for the issues and claims that remain unresolved by the Courts order, (ii) the immediate appeal on the rulings made to date in the order and/or (iii) mediation of the issues in dispute.

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 on the approximately 400-acre property in which the Company holds 100% of the oil and gas interest. 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 on-going 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.

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

Other contractual obligations

The following table summarizes the Company s contractual obligations, as of August 31, 2006 to make future payments under its convertible notes payable and office lease for the periods specified (in thousands):

	Payments Due by Period			
Contractual Obligations	**Total**	**2007**	**2008**	**2009**
Convertible Notes	$ 8,474	$	$	$ 8,474
Office Leases	93	70	23	
Total Contractual Cash Obligations	$ 8,567	$ 70	$ 23	$ 8,474

The above schedule assumes convertible note interest payments will be added to the principal amount (which is at the discretion of the Company), and the entire balance will be paid in full on maturity of May 24, 2009, and there will be no conversion of debt to common stock.

Rent expense was approximately $101,000 and $57,000 for the years ended August 31, 2006 and 2005, respectively.

Delay Rentals In conjunction with the Company s working interests in undeveloped oil and gas prospects, the Company must pay approximately $96,000 in delay rentals and other costs during the fiscal year ending August 31, 2007 to maintain the right to explore these prospects. The Company continually evaluates its leasehold interests, therefore certain leases may be abandoned by the Company in the normal course of business.

Environmental Oil and gas producing activities are subject to extensive Federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated.

Contingencies The Company 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 its business. The Company is not currently involved in any such incidental litigation which it believes could have a materially adverse effect on its financial condition or results of operations.

10. Operations by Geographic Area

Segment Information has been prepared in accordance with SFAS No. 131, *Disclosures About Segments of an Enterprise and Related Information.* The Company had two geographic reporting segments within the oil and gas exploration, development and production segment. Corporate expenses are not allocated to the geographic segments. The segment data present below was prepared on the same basis as the Consolidated Financial Statements.

Year ended August 31, 2006

	Oil and Gas Operations				
	Canada	United States	Total	Corporate	Total
Revenue	$ 10	$ 10,309	$ 10,319	$	$ 10,319
Expenses					
Operating costs	(15)	(2,221)	(2,236)		(2,236)
Net profits interest expense		(829)	(829)		(829)
Depreciation, depletion and amortization expense		(2,580)	(2,580)		(2,580)
Asset retirement obligation accretion		(22)	(22)		(22)
Earnings (loss) from operations	(5)	4,657	4,652		4,652
Corporate					
General and administrative				(2,256)	(2,256)
Depreciation and amortization				(14)	(14)
Interest income and other expenses				259	259
Interest expense				(371)	(371)
Earnings (loss) before income taxes	$ (5)	$ 4,657	$ 4,652	$ (2,382)	$ 2,270
Capital expenditures, net	$ 1	$ 9,705	$ 9,706	$ 29	$ 9,735

Property and equipment, net	$ 16	$ 20,405	$ 20,421	$ 45	$ 20,466

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Year ended August 31, 2005

	Oil and Gas Operations				
	Canada	United States	Total	Corporate	Total
Revenue	$ 1	$ 6,101	$ 6,102	$	$ 6,102
Expenses					
Operating costs	(5)	(1,099)	(1,104)		(1,104)
Net profits interest expense		(1,343)	(1,343)		(1,343)
Depreciation, depletion and amortization expense		(860)	(860)		(860)
Impairment of oil and gas properties	(580)		(580)		(580)
Asset retirement obligation accretion		(25)	(25)		(25)
Earnings (loss) from operations	(584)	2,774	2,190		2,190
Corporate					
General and administrative				(1,909)	(1,909)
Depreciation and amortization				(8)	(8)
Interest income and other expenses				82	82
Interest expense				(343)	(343)
Earnings (loss) before income taxes	$ (584)	$ 2,774	$ 2,190	$ (2,178)	$ 12
Capital expenditures	$ 37	$ 5,825	$ 5,862	$ 10	$ 5,872
Property and equipment, net	$ 15	$ 13,227	$ 13,242	$ 29	$ 13,271

11. Estimate of Proved Oil and Gas Reserves (Unaudited)

At August 31, 2006, the estimated oil and gas reserves presented herein were derived from a report prepared by Ryder Scott Company, an independent petroleum engineering firm. All reserves are located within the continental United States. The Company cautions that there are many inherent uncertainties in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are likely to change as future information becomes available, and these changes could be material.

The oil and gas reserve estimates presented below include all activity from the Company s oil and gas properties for 2006 and 2005. Proved oil and gas reserves are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods.

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Analysis Of Changes In Proved Reserves Estimated quantities of proved developed and undeveloped reserves, as well as the changes during the years ended August 31, 2005 and 2006, are as follows:

	Oil and Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved reserves at September 1, 2004	684,865	1,393,000
Purchase of reserves		1,610,852
Revisions of previous estimates	(80,027)	171,634
Extensions and discoveries	23,475	884,579
Production	(62,289)	(392,065)
Proved reserves at August 31, 2005	566,024	3,668,000
Purchase of reserves		1,636,235
Revisions of previous estimates	(1,990)	(914,767)
Extensions and discoveries	122,627	2,264,505
Production	(58,317)	(915,973)
Proved reserves at August 31, 2006	628,344	5,738,000
Proved developed reserves end of year		
August 31, 2005	503,767	1,345,000
August 31, 2006	518,788	2,755,000

The table below sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company s proved oil and gas reserves. Estimated future cash inflows were computed by applying year end (August 31) prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) averaging $67.12 and $66.95 per Bbl of oil and natural gas liquids and $5.49 and $11.74 per Mcf of gas for 2006 and 2005, respectively, to the estimated future production of proved oil and gas reserves. The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future corporate overhead expenses and interest expense have not been included. Discounting the annual net cash flows at 10% illustrates the impact of timing on these future cash flows.

Standardized Measure of Estimated Discounted Future Net Cash Flows

	2006 (In thousands)	2005
Future cash inflows	$ 73,657	$ 80,966
Future cash outflows:		

Production cost(1)	(23,168)	(24,168)
Development cost	(4,237)	(5,255)
Future net cash, before income taxes	46,252	51,543
Future income taxes	(661)	(813)
Future net cash flows	45,591	50,730
Adjustment to discount future annual net cash flows at 10%	(16,906)	(21,978)
Standardized measure of discounted future net cash flows	$ 28,685	$ 28,752

(1) Production costs include lease operating expenses, production and ad valorem taxes and net profits expense.

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PYR ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes the principal factors comprising the changes in the standardized measure of estimated discounted net cash flows for the years ending August 31, 2006 and 2005, respectively.

Changes in Standardized Measure of Estimated Discounted Net Cash Flows

	2006	2005
	(In thousands)	
Standardized measure, beginning of period	$ 28,752	$ 11,044
Sales of oil and gas, net of production costs and taxes	(7,254)	(3,655)
Purchase of reserves in place	3,994	7,232
Net change in sales prices, net of production cost	(13,628)	10,062
Discoveries, extensions and improved recoveries, net of future development cost	14,888	7,100
Development costs incurred	815	682
Change in future development costs	1,800	143
Revisions of quantity estimates	(3,266)	(4,398)
Changes in future income tax	70	(504)
Accretion of discount	2,514	1,046
Other		
Standardized measure, end of period	$ 28,685	$ 28,752

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EXHIBIT INDEX

Number	Description
3.1*	Articles of Incorporation, filed with the Maryland Secretary of State on June 18, 2001(1)
3.2*	Articles of Merger, filed with the Maryland Secretary of State on July 3, 2001 (1)
3.3*	Bylaws(1)
4.1*	Specimen Common Stock Certificate(2)
4.2*	Subscription and Registration Rights Agreement between Wellington parties and the Company, September 2005(3)
21	List of the Company s Subsidiaries
23.1	Consent of HEIN & Associates LLP
23.2	Consent of Ryder Scott Company
31.1	Certification of Chief Executive Officer
31.2	Certification of Chief Financial Officer
32.1	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Executive Officer
32.2	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Financial Officer

* Previously filed.

(1) Incorporated by reference from the Company s Form 10-KSB for the year ended August 31, 2001.

(2) Incorporated by reference from the Company s Form 10-KSB/A1 for the year ended August 31, 1997.

(3) Incorporated by reference from the Company s Report on Form 8-K filed on October 8, 2005.