PYR ENERGY CORP
Form 10-K
December 14, 2001

U.S. Securities And Exchange Commission
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended August 31, 2001

[ ] TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [No Fee Required]
For the transition period from _____ to _____

Commission File No. 0-20879

PYR ENERGY CORPORATION
(Name of registrant as specified 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 riling requirements for the past 90 days. Yes X No__

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (ss. 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-K or any amendment to this Form 10-K. [X]

As of December 12, 2001, the registrant had 23,691,357 common shares outstanding, and the aggregate market value of the common shares held by non-affiliates was approximately $36,234,000*. This calculation is based upon

the closing sale price of $1.99 per share on December 12, 2001.

* Without asserting that any of the issuer's directors or executive officers, or the entity that owns 3,113,923 shares of common stock is an affiliate, the shares of which they are beneficial owners have been deemed to be owned by affiliates solely for this calculation.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III, Items 11 and 12 is incorporated by reference from the registrant's definitive proxy statement relating to its 2002 annual meeting of stockholders to be filed within 120 days after August 31, 2001.

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PART I

ITEM 1. and ITEM 2. BUSINESS AND PROPERTIES

General

PYR Energy Corporation (referred to as "PYR", the "Company", "we", "us" and "our") is a development stage independent oil and gas exploration company with a strategic focus on exploring for and developing significant oil and gas reserves in deep, structurally complex formations. To date, the primary focus of our drilling activity has been in the San Joaquin Basin of California and on our East Lost Hills project there. We initiated this project in 1997 and brought in industry partners and commenced initial drilling in 1998. During the fiscal year ended August 31, 2001, we have focused our exploration efforts on the pre-drill phases of our other high potential exploration projects in the San Joaquin Basin and in the Rocky Mountain region. We continue to acquire acreage positions in exploration areas we have identified as having significant oil and gas reserve potential.

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.

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.

Developments During Fiscal 2001

Property Impairment

At August 31, 2001, the Company recorded a ceiling test write-down of $13,340,000 in conjunction with its capitalized oil and gas properties. This non-cash accounting charge is comprised of approximately $10,528,000 of costs at the Company's East Lost Hills project, which includes drilling and completion costs associated with its working interests in the ELH #1, ELH #2, ELH #3, Bellevue 1-17 and 1-17R wells and allocated land, geological and geophysical costs. Also included in the impairment are capital costs associated with the Company's Southeast Maricopa project and costs associated with the Company's interests in the Cal Canal and Lucky Dog prospects in the approximate amount of $2,812,000. As a result of this write-down, the Company reported a net loss for the year of $13,142,000. For additional information, see below, "--Property Impairment" and Note 1 to the Financial Statements included in this Form 10-K.

East Lost Hills, San Joaquin Basin, California

During our fiscal year ended August 31, 2001, we acquired, from a private entity, an additional 1.544% working interest at East Lost Hills. As a result of this acquisition, our total working interest in the approximately 37,000 gross and approximately 33,000 net acres increased to 12.1193%. The ELH #1 well began producing natural gas and liquid hydrocarbons on February 6, 2001, providing us

with our first revenues from oil and gas production. During March of 2001, the previous operator of the East Lost Hills project, Berkley Petroleum Inc., was acquired by Anadarko Petroleum Corporation and Anadarko became operator of the East Lost Hills project.

We participated in the drilling and completion of two additional East Lost Hills wells during fiscal 2001. The ELH #2 well was drilled and completed to a depth of 18,011 feet. Although this well flowed natural gas and liquid hydrocarbons upon production testing, we believe mechanical issues prevented a thorough test of the reservoir. This well has been shut-in, awaiting a decision by the participant group to connect this well to processing facilities. The ELH #3 well was drilled to test a separate structure directly west of the East Lost Hills structure. This well was drilled to 21,769 feet and, upon production testing, was found to be non-productive. Because this wellbore could potentially be used to sidetrack to a new location in the East Lost Hills structure, the ELH #3 well has not been plugged and abandoned.

We are participating in three additional wells currently drilling at East Lost Hills. Two of these wells, the ELH #4 and the ELH #9, are operated by Anadarko. We have a 12.1193% working interest in each of these wells. The ELH #4 well is approximately four miles southeast of the ELH #1 well and the ELH #9 well is approximately six miles southeast of the ELH #1 well. A third well, the Aera Energy LLC NWLH 1-22, operated by Aera Energy LLC, is currently drilling approximately 3.5 miles northwest of the ELH #1 well. We are participating in this well through a pooling arrangement at a 4.04% working interest.

During the first half of 2001, the East Lost Hills working interest owners participated in the acquisition of approximately 165 square miles of 3D seismic data, a portion of which encompasses the East Lost Hills acreage. Ongoing interpretation of the data is expected to assist in selection of potential delineation and development well locations.

Funding and Financing

On March 12, 2001, we received an aggregate $11.6 million in gross proceeds through the sale of 1,450,000 shares of our common stock. The common stock was sold pursuant to a shelf registration statement and prospectus supplement. After costs and expenses, we received a net of $11.44 million. Investors consisted of a total of ten separate funds managed by four California based institutions. For information on the use of the proceeds from this financing, see below, "Item 5. Markets For Common Equity And Related Stockholder Matters--Use of Proceeds."

During the fiscal year ended August 31, 2001, various outstanding warrants were exercised to purchase a total of 802,390 shares of our common stock, resulting in our receipt of $1,845,684 in aggregate proceeds.

Markets and Major Customers

We generated our first revenues from sales of oil and gas during our fiscal year ended August 31, 2001. Sales to ChevronTexaco accounted for all of our revenues. ChevronTexaco has gas gathering and processing capabilities and water disposal facilities in the area. Based on the general demand for gas, if for some unforeseen reason we were to lose ChevronTexaco as a customer, we believe that we would be able to find another customer. However, ChevronTexaco limits the amount of water it accepts at its water disposal facilities. In order to alleviate this constraint, the participants at East Lost Hills are planning to drill a water disposal well and install water disposal facilities. If we are

unable to dispose of produced water at the ChevronTexaco water disposal facility and if we are not successful in our attempt to drill and connect a water disposal well, we may not be able to find an alternative economical method to dispose of water. We believe this event could cause an interruption in production that may have a material adverse effect on our business.

Employees and Office Space

At August 31, 2001, PYR had seven full time employees. The Company believes that its relationship with its employees is satisfactory. None of the Company's employees are covered by a collective bargaining agreement. PYR leases approximately 3,800 square feet of office space in Denver, Colorado for its executive and administrative offices.

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 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 California and Rocky Mountain drilling and exploration projects,
- our control of pre-drill exploration phases, and
- our expertise in advanced seismic imaging.

To implement our strategy, we seek to:

- Expand Production and Cash Flow From East Lost Hills. On February 6, 2001, we commenced our first production from the ELH #1 well. The production from this well has been constrained by limitations in disposing production water. The participant group is in the preliminary stages of drilling a disposal well and building pipeline and disposal facilities in order to alleviate this constraint. Because of the water disposal constraint, no additional production can be brought on line at this time. Should the water disposal constraint be eliminated, the ELH #2 well could be connected to a processing facility. There are currently three additional wells drilling at East Lost Hills.
- Initiate Exploration Drilling on Our Other Projects. In addition to our East Lost Hills project, we control interests in several other exploration projects in the San Joaquin Basin and in select areas of the Rocky Mountains. The most notable projects in the San Joaquin Basin are our Wedge prospect and Bulldog prospect, which are large target reserve prospects located immediately to the northwest of our East Lost Hills acreage. In the Rocky Mountains, our most notable large target reserve potential project is our Montana Foothills project.
- Continue to Internally Generate Exploration Prospects. We believe that by continuing to generate 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 exploratory drilling.

Significant Projects

Our exploration activities are focused primarily in the San Joaquin Basin of California and in select areas of the Rocky Mountains. Advanced seismic imaging of the structural and stratigraphic complexities common to these regions provides us with the enhanced ability to identify significant oil and gas reserve potential. A number of these projects offer multiple drilling opportunities with individual wells having the potential of encountering multiple reservoirs.

The following is a summary of our exploration areas and significant projects. While actively pursuing specific exploration activities in each of the following areas, we continually review additional opportunities in these core areas and in other areas that meet our exploration criteria.

San Joaquin Basin, California

The San Joaquin Basin is one of the most productive oil and gas producing basins in the continental United States. Located about 100 miles northwest of Los Angeles, the basin contains 20 fields classified as giant, with each having produced over 100 million barrels of oil equivalent.

The San Joaquin Basin contains six of the 25 largest oil fields in the United States. All six of these fields were discovered between 1890 and 1911. The basin accounts for 34% of California's actively producing fields, yet produces more than 78% of the state's total oil and gas production. Most of the production within the basin is located along the western and southern end of Kern County.

The San Joaquin Basin has been dominated by major oil companies with large fee acreage holdings and has generally been under-explored by independent exploration and production companies. The large fields in the basin were discovered on surface anticlines and produce predominantly heavy oil from depths of less than 5,000 feet. As a consequence, basin operators have focused on engineering technologies related to enhanced production practices, including steam floods and, most recently, horizontal drilling. Deep basin targets, both structural and stratigraphic in nature, remain largely untested with modern seismic technology and the drill bit. Our analysis of seismic data leads us to believe that multiple deep exploration opportunities exist in the San Joaquin Basin.

East Lost Hills. During 1997, we identified and undertook technical analysis of a deep, large, untested structure in the footwall of the Lost Hills thrust. This prospect lies directly east of and structurally below the existing Lost Hills field, which has produced in excess of 350 million barrels of oil equivalent from shallow depths.

In early 1998, we entered into an exploration agreement with a number of joint interest partners to participate in the drilling of an initial exploration well. We received cash for our share of acreage in this project and retained a working interest of 10.575%. Of our total working interest, 6.475% was carried

in the initial well. During November 2000, we purchased an additional working interest of 1.5443% at East Lost Hills to bring our current working interest to 12.1193%.

On May 15, 1998, drilling began on the Bellevue Resources et al. #1-17 East Lost Hills initial exploration well, located in Kern County, California. The well had a target depth of 19,000 feet. On November 23, 1998, the well had just penetrated the uppermost Temblor sand at 17,600 feet when it blew out and ignited. On December 18, 1998, the Bellevue #1-17R relief well began drilling. The relief well was drilled to 16,668 feet, where it intersected Bellevue #1-17 well bore. On May 29, 1999, the Bellevue #1-17 well was controlled by pumping

heavy mud and cement into the well bore. The Bellevue #1-17 well bore has been plugged and abandoned, and the Bellevue #1-17R well was sidetracked as a replacement well into the targeted Temblor formation.

On August 26, 1999, we and other working interest owners began drilling the ELH #1 well, approximately two miles northwest of the Bellevue #1-17R well. On April 12, 2000, this well had drilled to a total depth of 19,724 feet. Production testing began on May 28, 2000. On July 6, 2000, based on the results of the production testing and other analysis, we announced a natural gas discovery at the East Lost Hills field. Onsite production facilities, 8.4 miles of natural gas pipeline and 4.2 miles of water disposal pipeline was installed and, on February 6, 2001, we commenced commercial production of natural gas and liquid hydrocarbons from this well.

Since shortly after commencing production on February 6, 2001, the production from the ELH #1 well has been constrained by a variety of factors. Most recently, the major constraint inhibiting production has been the lack of adequate capacity for disposal of the produced water. Production water has been and continues to flow through a disposal pipeline connected to disposal facilities owned by ChevronTexaco. ChevronTexaco limits the amount of water accepted at its disposal facility. During the fourth fiscal quarter, the ELH #1 well produced a total of approximately 365 mmcfe, averaging approximately four mmcfe per day. Water production during this period averaged approximately 6,350 barrels per day.

During the first months of production, the ELH #1 well was shut-in for varying time periods ranging from a few hours to multiple days due to operational difficulties at the ChevronTexaco processing plant, shut-in pressure testing at the well, rolling brown-outs that were affecting California at the time and for general maintenance/testing reasons. During this period of random shut-ins, produced water would typically load in the well and when the ELH #1 well was put back on line, the water to gas ratio would generally increase. Over a period of months, the water to gas ratio reached the point where ChevronTexaco is requiring a decrease in the overall flow accepted at the processing and disposal facilities. The water to gas ratio increase became most apparent late in the Company's fourth fiscal quarter and has continued. It is unknown whether this ratio increase is an independent function of the reservoir or if the decline in the performance of the well is attributable solely to water loading from curtailment in overall flow rates. The participants are currently in the process of preparing to drill a water disposal well and to build associated pipeline and disposal facilities in order to remove the water disposal constraint that has affected the ELH #1 well. It is unknown whether removing the water disposal constraint will result in a decrease in the water to gas ratio.

On July 11, 2000, the participants commenced drilling the ELH #2 well. This

well is located approximately 1.5 miles northwest of the ELH #1 well. The ELH #2 well reached total depth of 18,011 feet in December 2000. While the final liner was run to total depth during the completion process, a portion of the drill pipe was inadvertently cemented in place across all potential pay zones. The Company believes that this mechanical issue may have prevented a thorough production test. Although the well production tested at approximately three mmcf per day, water disposal facilities are not yet available. This well has been suspended pending the ability and the decision to connect to processing and water disposal facilities.

On June 19, 2000, the participants at East Lost Hills commenced drilling the ELH #3 well. This well was designed to test a geologically separate feature than the structure encountered by the Bellevue #1-17, Bellevue #1-17R, ELH #1 and ELH #2 wells. This well was drilled to a total depth of 21,769 feet and upon production testing was determined to be non-productive. Because this wellbore may be used to sidetrack to a new location in the East Lost Hills structure, the ELH #3 well has not been plugged and abandoned.

The ELH #4 well commenced drilling on November 26, 2000 at a location approximately four miles southeast of the ELH #1 well. This well reached a total depth of 20,800 feet on August 7, 2001. Log and coring analysis was performed and it was determined that in order to maximize potential production, the wellbore should be sidetracked and directed to a more crestal position within the lower Temblor. On October 16, 2001, sidetrack drilling operations commenced to drill to a projected depth of 20,500 feet. As of December 12, 2001, this well was drilling at approximately 19,450 feet.

The ELH #9 well is currently drilling at a location approximately six miles southeast of the ELH #1 well. This well commenced drilling operations on July 17, 2001 with a projected total depth in the lower Temblor of 21,000 feet. This well continued to drill at an approximate depth of 17,600 feet as of December 12, 2001.

We are participating in a third well currently drilling at East Lost Hills. The Aera Energy LLC NWLH 1-22 well located in Section 22, T25S-R20E commenced drilling on August 23, 2001. This well is approximately three and a half miles northwest of the ELH #1 well and is designed to test the Temblor formation to a projected depth of 20,000 feet. We are participating in this well operated by Aera Energy LLC, through a pooling arrangement at a 4.04% working interest. At December 12, 2001, this well was beginning to enter zones of interest.

The participants may commence drilling operations on up to three additional wells in this prospect during the fiscal year ending August 31, 2002, although there is no assurance this will occur.

Wedge Prospect. This is a seismic generated 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 that has proven productive at East Lost Hills, extends approximately ten miles further northwest of the East Lost Hills Area of Mutual Interest and can be encountered as much as 3,000 feet higher. We currently control approximately 14,000 gross and approximately 13,000 net acres here. Our approach is to sell down our working interest and to retain a 25% to 40% working interest in this prospect.

Bulldog Prospect. This project is a 2D seismic generated light oil and natural gas 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. We currently control approximately 16,000 gross and approximately 15,000 net acres here. We are in the process of securing industry participation to drill a 14,000 foot test well and expect to retain a 25% to 40% working interest in this prospect.

Greater San Joaquin Basin Projects. In April 1999, we purchased a working interest in three additional deep exploration projects in the San Joaquin Basin. These three projects are outside the East Lost Hills joint venture area. Our working interests range from 3.00% to 3.75% in each of the three exploration projects, with a carried interest in the initial test well in each. These projects target the Temblor formation at depths ranging from 15,000 to 19,000 feet.

The Pyramid Power project is a 2D seismic generated natural gas prospect. An initial exploration well, operated by Anadarko and located in Section 9, T25S-R18E, commenced drilling on November 22, 2001. This exploration well is designed to test the Temblor and the Point of Rocks formation to a total depth of 18,500 feet. PYR owns a 3.75% working interest in this prospect acreage with its interest in this initial well being carried through the tanks. The participants at Pyramid Power jointly control approximately 20,000 gross and 15,000 net acres over the prospect. At December 12, 2001, this well was drilling at a depth of approximately 8,500 feet.

An exploration well began drilling in the Cal Canal area on June 15, 1999 and was drilled to a total depth of 18,100 feet. After the participants concluded that a completion in the upper portion of the Temblor formation was not warranted, the well was completed in the shallower McDonald formation, and a production test resulted in non-commercial hydrocarbon flow rates. Although this well has not been plugged and abandoned, no further drilling is planned.

The third project, named Lucky Dog, has been terminated and no drilling is expected to occur on this prospect.

Rectange Force Project. We own a 30% working interest in approximately 6,000 gross acres in this San Joaquin Basin project that targets the deep Temblor formation. We may elect to participate in the drilling of an initial exploration well here at the current 30% ownership, or may elect to sell down our interest for cash and/or a carried working interest in the initial well. This project is still in the development stage and no drilling plans currently are in place.

Rocky Mountain Exploration

Montana Foothills Project. This extensive natural gas project, located in northwestern Montana, is part of the southern Alberta basin, and has been classified as the southern extension of the Alberta Foothills producing province. The USGS and numerous Canadian industry sources have estimated extremely significant recoverable reserves for the Montana portion of the Foothills trend. Based on extensive geologic and seismic analysis, we have identified numerous structural culminations of similar size, geometry, and kinematic history as prolific Canadian foothills fields, such as Waterton and Turner Valley.

The geologic setting and hydrocarbon potential of this area was not recognized by industry until the early 1980s. At that time, a number of companies initiated exploration efforts, including Exxon, Arco, Chevron, Amoco, Conoco, and Unocal. This initial exploration phase culminated in a deep test by Unocal in 1989. Although this well was unsuccessful, recent improvements in seismic imaging and pre-stack processing have resulted in our recognizing that this test well was drilled based upon a misleading seismic image and was located significantly off-structure.

We currently control approximately 262,000 gross and 224,000 net acres in this project and are currently presenting this project to potential industry participants in order to sell down our working interest and generate exploratory drilling activity. We anticipate retaining a working interest in this project of between 20% to 40%.

Wyoming Projects. We have three separate exploration projects in Wyoming, and have acquired an initial land position of approximately 8,000 gross and net acres. We intend to acquire additional land holdings as opportunities arise. We currently are interpreting seismic data and conducting other geophysical activities.

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. As used in this document, the term "Mcf" means thousand cubic feet.

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.

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.

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.

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.

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.

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

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.

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.

Production and Productive Wells

On February 6, 2001, we commenced our first production from the ELH #1 well at East Lost Hills. At August 31, 2001, the Company had production from only the ELH #1 well. From February 6, 2001 through August 31, 2001, the Company's net share of production from this well was 99,535 mcf of natural gas and 5,804 barrels of liquid hydrocarbons.

Drilling Activities

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

- During the fiscal year ended August 31, 2001, we participated in the drilling of three gross (0.283 net) development wells, all at East Lost Hills. The ELH #4 well commenced drilling on November 26, 2000 and after a sidetrack operation, the well, on December 12, 2001, was drilling at approximately 19,450 feet. The ELH #9 well commenced drilling on July 18, 2001 and, on December 12, 2001, was drilling at a depth of approximately 17,600 feet. On August 23, 2001, the Aera Energy LLC NWLH 1-22 well commenced drilling and, on December 12,

2001, continued to drill toward its target depth of 20,000 feet.

- During the fiscal year ended August 31, 2000, we participated in the drilling of one gross (0.121 net) exploration well and one gross (0.121 net) development well that commenced drilling during that fiscal year. The exploration well is the ELH #3 and the development well is the ELH #2. The ELH #2 well reached total depth in December 2000 and was completed and production tested. This well has been suspended pending potential connection to processing facilities.

- During the fiscal year ended August 31, 1999, we participated in the drilling of three gross (0.147 net) exploratory wells that began drilling during that fiscal year. These wells consist of the Bellevue #1-17R relief well, a Cal Canal exploratory well and the ELH #1 well. The Bellevue #1-17R relief well began drilling on December 18, 1998 and was used to control the Bellevue #1-17 well blowout. The Bellevue #1-17R well then was sidetracked as a replacement well. Operations on this well have been suspended. After an unsuccessful production test, operations on the Cal Canal well have been suspended. The ELH #1 well was completed and began producing on February 6, 2001.

Although there is no assurance that any additional wells will be drilled, we anticipate we may commence drilling up to three additional wells during fiscal 2002 in our East Lost Hills project. We also may participate in the drilling of up to four exploration wells during fiscal 2002 on our other

exploration projects. 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.

Reserves

We commenced our first production from the ELH #1 well at East Lost Hills on February 6, 2001, and during our fiscal year ended August 31, 2001, we generated approximately $1,202,000 as our first revenues from oil and gas production from the ELH #1 well. Concurrent with the end of our fiscal year, we engaged Netherland, Sewell & Associates, Inc., independent petroleum engineers, to prepare a reserve report for our ownership interest in the East Lost Hills project. Previous to August 31, 2001, all of our oil and gas properties were classified as undeveloped, and no reserve reports were warranted.

The estimates of proved reserves are based on the information available at this time, most importantly the production history of ELH #1, which has been constrained by inadequate water disposal facilities for most of its nine-month history. In addition, the estimates of capital costs to drill potential offset wells are based upon the actual costs of drilling the initial East Lost Hills wells, which were negatively affected by mechanical difficulties associated with drilling in a very difficult and challenging environment. Based on this historical data of constrained production and drilling costs affected by significant mechanical difficulties, the reserve report concludes that it would be uneconomic to produce oil and gas reserves at East Lost Hills. Therefore, at August 31, 2001, the reserve report from our independent petroleum engineers shows no proved reserves. As experience is gained in drilling additional wells, and as more production, tests, and pressure data become available, future reserve estimates could change, but there is no assurance this will be the case.

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.

Property Impairment

As required for oil and gas companies that utilize the full cost method of accounting for oil and gas activities, we capitalize all costs associated with acquisition, exploration and development activities. Capitalized costs, excluding costs of investments in unproved properties and major development projects, are subject to a "ceiling test limitation". Under the ceiling test, capitalized costs 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. If capitalized costs exceed this ceiling, an impairment is recognized.

As described above under "--Reserves," we had no proved reserves as of August 31, 2001. As a result, we are required to record an impairment against our entire amortizable cost pool. This charge has no impact on our cash or cash flows. At August 31, 2001, our amortizable cost pool was comprised of East Lost Hills drilling and completion costs associated with our working interests in the ELH #1, ELH #2, ELH #3, Bellevue 1-17 and 1-17R wells and allocated land, geological and geophysical costs in the aggregate amount of $10,528,000, and

capital costs associated with our Southeast Maricopa project, Cal Canal prospect and Lucky Dog prospect in the amount of $2,812,000. The unevaluated costs that remain in our full cost pool include drilling costs associated with our working interest in the ELH #4 and ELH #9 wells, and allocated land and geological and geophysical costs associated with our East Lost Hills project and other exploration projects. Additional discussion of the charge, including information regarding the methodology prescribed for computing the full cost ceiling, is presented in Note 1 to our Financial Statements in this Annual Report on Form 10-K.

Acreage

We currently control through lease, farmout, and option, the following approximate acreage position as detailed below:

State	Gross Acres	Net Acres
California	104,000	40,000
Colorado	11,000	7,000
Montana	260,000	224,000
Wyoming	8,000	8,000

TOTAL	383,000	279,000

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 do not operate any properties. 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.

Commencing in April 1992, the FERC issued Order Nos. 636, 636-A, 636-B, 636-C and 636-D ("Order No. 636 "), which require interstate pipelines to provide transportation services separately, or "unbundled," from the pipelines' sales of gas. Also, Order No. 636 requires pipelines to provide open access transportation on a nondiscriminatory basis that is equal for all natural gas shippers. Although Order No. 636 does not directly regulate our production activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. It is unclear what impact, if any, increased competition within the natural gas industry under Order No. 636 will have on our activities.

The courts have largely affirmed the significant features of Order No. 636 and numerous related orders pertaining to the individual pipelines, although certain appeals remain pending and the FERC continues to review and modify their open access regulations. In particular, the FERC is conducting a broad review of its transportation regulations, including how they operate in conjunction with state proposals for retail gas market restructuring, whether to eliminate cost-of-service rates for short-term transportation, whether to allocate all short-term capacity on the basis of competitive auctions, and whether changes to long-term transportation policies may also be appropriate to avoid a market bias toward short-term contracts. In February 2000, the FERC issued Order No. 637 amending certain regulations governing interstate natural gas pipeline companies in response to the development of more competitive markets for natural gas and natural gas transportation. The goal of Order No. 637 is to "fine tune" the open access regulations implemented by Order No. 636 to accommodate subsequent changes in the market. Key provisions of Order No. 637 include: (1) waiving the price ceiling for short-term capacity release transactions until September 30, 2002, subject to review and possible extension of the program at that time; (2) permitting value-oriented peak/off peak rates to better allocate revenue responsibility between short-term and long-term markets; (3) permitting term-differentiated rates, in order to better allocate risks between shippers and the pipeline; (4) revising the regulations related to scheduling procedures, capacity, segmentation, imbalance management, and penalties; (5) retaining the right of first refusal ("ROFR") and the five year matching cap for long-term shippers at maximum rates, but significantly narrowing the ROFR for customers that the FERC does not deem to be captive; and (6) adopting new website reporting requirements that include daily transactional data on all firm and interruptible contracts and daily reporting of scheduled quantities at points or segments. The new reporting requirements became effective September 1, 2000. We cannot predict what action the FERC will take on these matters in the future,

nor can we accurately predict whether the FERC's actions will, over the long term, achieve the goal of increasing competition in markets in which our natural gas, once produced, is sold. However, we do not believe that we will be affected by any action taken materially differently than other natural gas producers and marketers with which we compete.

Commencing in October 1993, the FERC issued a series of rules (Order Nos. 561 and 561-A) establishing an indexing system under which oil pipelines are able to change their transportation rates, subject to prescribed ceiling levels. The indexing system, which allows pipelines to make rate changes to track changes in the Producer Price Index for Finished Goods, minus one percent, became effective January 1, 1995. We do not believe that these rules affect us any differently than other oil producers and marketers with which we will 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 recently issued a final rule that amended its regulations governing the valuation of crude oil produced from federal leases. This new 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. The lawfulness of the new rule has been challenged in federal court. We cannot predict whether this new rule will be upheld in federal court, nor can we predict whether the MMS will take further action on this matter. However, we do not believe that this new rule 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.

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. Further, pursuant to a 1996 law passed by the California State Assembly, certain segments of the power generation industry in the state were deregulated. Toward the end of calendar 2000, this statute, along with the significantly increased demand for natural gas, the increased price of natural gas and other fuels, and the overall increase in the demand for and cost of power generation had created a major crisis in California. The crisis threatened to bankrupt many electric utilities because of state-imposed limits on the ability to pass costs through to the utilities' customers. Because of a general decline in demand for natural gas, the build up of natural gas in storage and the resulting decrease in natural gas prices, the energy crisis in California does not currently exist. However, because natural gas-driven turbines generate a substantial portion of California's electricity supply, it is possible that laws or regulations imposed at the state or federal level intended to alleviate a potential future crisis would have a material adverse impact on natural gas prices, marketing activities, operations or production.

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 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. 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 operating history in the oil and gas business. 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 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.

Our operations require large amounts of capital. Our current development plans will require us 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 a minimum of approximately $7 million on exploration and development activities during our fiscal year ending August 31, 2002. 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. We currently do not have any sources of additional financing. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the success of our natural gas project in the San Joaquin Basin,
- 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 depend heavily on expansion and development in the San Joaquin Basin. All of our current drilling activity is in the San Joaquin Basin, and our future growth plans rely heavily on initiating and increasing production and reserves in the San Joaquin Basin. This lack of diverse business operations subjects us to a high degree of risk.

Our development plan includes establishing and then increasing reserves through continued drilling and development of our existing properties in the San Joaquin Basin. We cannot be sure, though, that our planned projects in the San Joaquin Basin will lead to significant additional 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.

Our non-operator status limits our control over our oil and gas projects. We focus primarily on creating exploration opportunities and forming industry alliances to develop those opportunities. 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 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,
- 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 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 commenced our first oil and gas production on February 6, 2001, resulting in a change of classification of a

component of our capitalized oil and gas properties from undeveloped to developed. We engaged an independent engineering firm to conduct a reserve analysis and to prepare a reserve report for the East Lost Hills project. This report reflected no economic reserves at our fiscal year ended August 31, 2001. As a result, we have recorded a write-down of approximately $13,340,000 to reduce the carrying value of our oil and gas properties. Additional discussion of this charge is presented in Note 1 to our Financial Statements in this Annual Report on Form 10-K.

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.

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.

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 depend on key personnel. We are highly dependent on the services of D. Scott Singdahlsen, our President and Chief Executive Officer, and our other geological and geophysical staff members. The loss of the services of any of these persons could hurt our business. We do not have an employment contract with Mr. Singdahlsen or any other employee.

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 PYR, our business or our management, are intended to identify forward-looking statements.

ITEM 3. LEGAL PROCEEDINGS

The Company is not a party to any other current or pending legal proceeding (nor are any of the Company's properties subject to a pending legal proceeding).

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

There were no matters submitted to a vote of the Company's security holders during the fourth quarter of the fiscal year ended August 31, 2001.

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. Before then it was included for quotation on the OTC Bulletin Board under the symbol "PYRX." 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, 2000		
First Quarter	$5.312	$3.625
Second Quarter	4.625	2.875
Third Quarter	5.938	2.750
Fourth Quarter	7.125	3.500
Fiscal Year Ended August 31, 2001		
First Quarter	$7.625	$4.500
Second Quarter	9.960	6.000
Third Quarter	9.900	5.070
Fourth Quarter	8.700	1.750

On December 12, 2001, the last reported sales price of our common stock on the AMEX was $1.99.

Stockholders Of Record

As of December 12, 2001, the number of record holders of our common stock was approximately 800 and the number of beneficial owners of our common stock was approximately 3,600.

Dividends

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

Use Of Proceeds

On January 5, 2001, our "shelf" registration statement (SEC file number 333-51764), pertaining to the sale from time to time of up to $75 million of our securities, was declared effective by the Securities and Exchange Commission. The securities that may be offered by the Company pursuant to this registration statement may include shares of common stock, shares of preferred stock, which may be issued in the form of depositary shares evidenced by depositary receipts, warrants to purchase common stock, preferred stock or any combination of those securities, or any combination of any of these securities.

On March 9, 2001, we received a total of $11.6 million in gross proceeds from the sale of 1,450,000 shares of our common stock. The common stock was sold pursuant to a prospectus supplement with respect to the shelf registration statement. We incurred offering expenses of $160,470 in this offering, so that we received net proceeds of $11,439,530 from this sale of common stock. These expenses do not include any direct or indirect payments to directors, officers, persons owning 10% or more of any class of equity securities, or affiliates of the Company. Because these securities were sold directly by the Company in an offering that did not involve an underwriter, we did not pay any underwriting discounts or commissions, finder's fees or other expenses to or for

underwriters.

Through August 31, 2001, $2,963,058 of the proceeds from this sale of common stock have been used as described in the prospectus supplement to fund our planned exploration and development activities, primarily in the San Joaquin Basin of California. As of August 31, 2001, the balance of the net proceeds continue to be held for those purposes and for possible acquisition and general corporate purposes as described in the prospectus supplement.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth certain selected financial data of the Company for each of the last five fiscal years ended August 31:

	Fiscal Year Ended		
	2001	2000	1999
Operating Revenues	$ 1,624,096	$ 165,411	$ 116,713
Net (loss) from operations	(13,142,291)	(982,547)	(1,140,407
Net income (loss(per share)	(.59)	(.07)	(.11
Total assets at the end of each period	22,067,184	19,942,090	10,762,521
Long-term debt at the end of each period	-0-	-0-	1,062

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

The following discussion should be read in conjunction with the 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-K.

Overview

We are a development stage independent oil and gas exploration company whose strategic focus is the application of advanced seismic imaging and computer aided exploration technologies in the systematic search for commercial hydrocarbon reserves, primarily in the onshore western United States. We attempt to leverage our technical experience and expertise with seismic data to identify exploration and exploitation projects with significant potential economic return. 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. Our financial results depend on our ability to sell prospect interests to outside industry participants. We will not be able to commence 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 exists. 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.

Liquidity and Capital Resources

At August 31, 2001, we had approximately $8,786,000 in working capital.

During the fiscal year ended August 31, 2001, our capitalized costs for undeveloped oil and gas properties decreased by approximately $316,000. The decrease is the result of an impairment taken against our oil and gas properties in the amount of $13,340,000, offset by approximately $13,024,000 of costs incurred for drilling and completion, the cost of acquiring an additional 1.5433% working interest in our East Lost Hills project, transportation pipeline costs, production facilities costs, delay rentals, and other related direct costs with respect to our exploration and development projects.

During the fiscal year ended August 31, 2000, our capitalized costs for undeveloped oil and gas properties increased by approximately $6,230,000. This net increase is comprised of total costs of approximately $6,430,000 for drilling costs, costs associated with acquiring and retaining exploration acreage, seismic costs associated with undeveloped oil and gas projects, and reclassification of costs paid during the fiscal year ended August 31, 1999 for claims relating to the 1998 blowout, offset by a property impairment of $200,000 recorded against our Cal Canal project.

During the fiscal year ended August 31, 1999, our capitalized costs for undeveloped oil and gas properties increased by a net amount of approximately $2,572,000. This net increase is comprised of expenditures on undeveloped oil

and gas prospects of approximately $2,878,000, offset by property abandonments and impairments of approximately $306,000.

During the quarter ended November 30, 2000, the holders of our Series A Convertible Preferred Stock converted all of the remaining outstanding shares of Series A Convertible Preferred Stock into shares of common stock at a conversion price of $.60 per share. This resulted in a cashless transaction whereby 14,263 shares of Series A Convertible Preferred Stock were converted into a total of 2,377,234 shares of common stock. At November 30, 2000, there were no remaining shares of Series A Convertible Preferred Stock outstanding. In November 2000, warrants to purchase 100,000 shares of common stock issued in connection with the private placement of the Series A Convertible Preferred Stock were exercised at the exercise price of $0.75 per share. In December 2000, warrants to purchase an additional 16,667 shares of common stock were exercised. We received $87,500 in cash as the result of these exercises. There are no additional outstanding warrants associated with this private placement.

During the quarter ended November 30, 2000, warrants were exercised to purchase a total of 17,125 shares of our common stock at a purchase price of $2.50 per share. Total proceeds received from this warrant exercise were $42,813. Previously, during the fiscal year ended August 31, 2000, warrants were

exercised to purchase a total of 164,063 shares of our common stock for total proceeds issued in the May 1999 private placement had been of $410,157. During December 2000, all the remaining outstanding warrants from the May 1999 private placement were exercised to purchase an aggregate of 256,312 shares of common stock, resulting in aggregate proceeds to us of $640,781.

During November 2000 and January 2001, warrants issued in conjunction with the August 2000 private placement were exercised to purchase 144,286 shares of common stock at an exercise price of $4.80 per share. This resulted in proceeds to us of $692,573.

During January 2001, the holders of the remaining outstanding warrants issued in connection with a private placement that was completed in May 2000 exercised their warrants to purchase an aggregate of 22,000 shares of common stock for $93,500.

On March 12, 2001, we received an aggregate $11,600,000 in gross proceeds through the sale of 1,450,000 shares of our common stock. The common stock was sold pursuant to a shelf registration statement and prospectus supplement. After costs and expenses, we received a net of $11,440,000. Investors consisted of a total of ten separate funds managed by four California based institutions.

We had no outstanding long-term debt at August 31, 2001 or at August 31, 2000. We have not entered into any commodity swap arrangements or hedging transactions. Although we have no current plans to do so, we may enter into commodity swap and hedging transactions in the future in conjunction with oil and gas production.

It is anticipated that the future development of our business will require additional, and possibly substantial, capital expenditures. Our capital expenditure budget for the fiscal year ending August 31, 2002 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 continuing results at our East Lost Hills project. We anticipate spending a minimum of approximately $7 million for capital expenditures relating to our existing drilling commitments and related development expenses, and other exploration costs. 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.

Capital Expenditures

During fiscal 2001, we incurred approximately $10,922,000 for costs relating to drilling and completing wells at our East Lost Hills Project, and for acquiring an additional 1.554% working interest at East Lost Hills. We incurred approximately $2,102,000 for costs related to our other exploration projects including continued leasing and optioning of acreage. We generated $1,201,979 in revenues from oil and gas production during 2001.

During fiscal 2000, we incurred approximately $1,319,000 for costs related to continued leasing and optioning of acreage and approximately $4,038,000 for drilling and seismic costs associated with deep exploratory drilling at our East

Lost Hills project. We had no revenues from oil and gas production during 2000.

During fiscal 1999, we incurred approximately $876,000 for costs related to continued leasing and optioning of acreage, $1,094,000 for positions in additional exploration projects in California, $313,000 for costs relating to seismic and $480,000 in drilling costs associated with deep exploratory drilling at our East Lost Hills project.

We currently anticipate that we will participate in the drilling of from three to seven wells during our fiscal year ending August 31, 2002, although the number of wells may increase as additional projects are added to our portfolio. However, there can be no assurance that any such wells will be drilled and if drilled that any of these wells will be successful.

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.

Results of Operations

The twelve months ended August 31, 2001 ("2001") compared with the twelve months ended August 31, 2000 ("2000")

Operations during the fiscal year ended August 31, 2001 resulted in a net loss of $13,142,291 compared to a net loss $982,547 for the fiscal year ended August 31, 2000.

Oil and Gas Revenues and Expenses. Production commenced at the East Lost Hills ELH #1 well on February 6, 2001. We recorded $1,055,382 from the sale of 99,535 mcf of natural gas for an average price of $10.60 per mcf and $146,597 from the sale of 5,804 bbls of hydrocarbon liquids for an average price of

$25.26 per barrel during the year ended August 31, 2001. Lease operating expenses during this period were $102,018. We recorded no revenues or expenses from oil and gas operations for the year ended August 31, 2000. None of our oil or gas properties was producing before February 6, 2001.

Interest Income. We recorded $422,117 and $165,411 in interest income for the years ended August 31, 2001 and August 31, 2000, respectively. The increase in the year ended August 31, 2001 is attributable to interest earned on cash balances remaining from the common stock offering in March 2001 and the private placement completed in August of 2000.

General and Administrative Expense. We incurred $1,306,635 and $929,420 in general and administrative expenses during 2001 and 2000, respectively. The increase is primarily attributable to unrecoverable financing costs and increases in personnel and salaries.

Depreciation, Depletion and Amortization. We recorded no depreciation, depletion and amortization expense from oil and gas properties for the years ended August 31, 2001 or August 31, 2000. Although we commenced our first production during 2001, we recorded an impairment against our entire amortizable

full cost pool at August 31, 2001, and therefore had no costs to amortize. In the prior year, none of our oil and gas properties were producing and, therefore no DD&A expense was recognized. We recorded $17,823 and $18,327 in depreciation expense associated with capitalized office furniture and equipment during the years ended August 31, 2001 and August 31, 2000, respectively.

Dry Hole, Impairment and Abandonments. In 2001, we recorded an impairment of $13,340,000 against our oil and gas properties as the result of the capitalized costs of a portion of our oil and gas properties exceeding the present value of estimated future net revenues of proved reserves. The costs from this impairment relating to our East Lost Hills project include drilling and completion costs associated with our working interests in the ELH #1, ELH #2, ELH #3, Bellevue 1-17 and 1-17R wells and allocated land, geological and geophysical costs. In addition, we have recorded property impairments with respect to our Southeast Maricopa project and our interests in the Cal Canal and Lucky Dog prospects in the approximate amount of $2,812,000. In 2000, we recorded an impairment of $200,000 against our Cal Canal project.

Interest Expense. We recorded no interest expense for the year ended August 31, 2001 and nominal interest expense for the year ended August 31, 2000.

The twelve months ended August 31, 2000 ("2000") compared with the twelve months ended August 31, 1999 ("1999")

Operations during the fiscal year ended August 31, 2000 resulted in a net loss of $982,547 compared to a net loss $1,140,407 for the fiscal year ended August 31, 1999.

Oil and Gas Revenues and Expenses. At August 31, 2000 and August 31, 1999, the Company did not own any producing or proved oil and gas properties, and no oil and gas production revenues or expenses had been recorded by the Company.

General and Administrative Expense. The Company incurred $929,000 and $743,000 in general and administrative expenses during 2000 and 1999, respectively. The increase results from increases in shareholder and investor relations costs resulting from our listing on the American Stock Exchange and from our expanding investor and shareholder base, and from additional increases in personnel and salaries.

Dry Hole, Impairment and Abandonments. In 2000, the Company recorded an impairment of $200,000 against its Cal Canal project. In 1999, the Company re-evaluated its School Road project and recorded an impairment of approximately $285,000 against its basis in this project. Also in 1999, the Company had abandoned projects and recorded an abandonment cost of approximately $21,000 associated with these projects.

Interest Expense. The Company recorded nominal interest expense in 2000. The Company recorded $183,000 in interest expense during 1999, predominately associated with the 10% Convertible Debentures that were outstanding from October 26, 1998 through April 16, 1999. Per the Convertible Debenture agreement, the Company elected to pay this interest by issuing 53,326 shares of the Company's common stock. These Debentures were converted into Series A Convertible Preferred Stock on April 16, 1999. The Company is obligated to pay a 10 percent dividend on the outstanding preferred stock. During 2000, the Company paid dividends to the holders of preferred stock of approximately $178,600 by issuing a total of 38,531 shares of common stock.

Depreciation, Depletion and Amortization. The Company recorded no depletion expense from oil and gas properties in 2000 or 1999. At August 31, 2000 and 1999, the Company did not own any proved reserves and had no oil or gas production. The Company recorded $18,327 and $24,111 in depreciation expense associated with capitalized office furniture and equipment during 2000 and 1999, respectively.

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

The information required under Item 7A is not applicable.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTAL DATA

The Financial Statements and schedules that constitute Item 8 are attached at the end of Annual Report on Form 10-K. An index to these Financial Statements and schedules is also included in Item 14(a) of this Annual Report on Form 10-K.

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

Not applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF REGISTRANT

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
D. Scott Singdahlsen	43	Chief Executive Officer, President, and Chairman Of the Board	1997
Andrew P. Calerich	37	Chief Financial Officer, Vice President and Secretary	---
Keith F. Carney	45	Director	1997
S. L. Hutchison	68	Director	1999
Bryce W. Rhodes	48	Director	1999
Kenneth R. Berry, Jr.	49	Vice President-Land	---

D. Scott Singdahlsen has served as President, Chief Executive Officer, and Chairman of the Board of the Company since August 1997. Mr. Singdahlsen co-founded PYR Energy, LLC in 1996, and served as General Manager and Exploration Coordinator. In 1992, Mr. Singdahlsen co-founded Interactive Earth Sciences Corporation, a 3-D seismic management and interpretation consulting

firm in Denver, where he served as vice president and president and lead seismic interpretation specialist from 1992 to 1996. Prior to forming Interactive Earth Sciences Corporation, Mr. Singdahlsen was employed as a Development Geologist for Chevron USA in the Rocky Mountain region. At Chevron, Mr. Singdahlsen was involved in 3-D seismic reservoir characterization projects and geostatistical analysis. Mr. Singdahlsen started his career at UNOCAL as an Exploration Geologist in Midland, Texas. Mr. Singdahlsen earned a B.A. in Geology from Hamilton College and a M.S. in Structural Geology from Montana State University.

Andrew P. Calerich has served as Chief Financial Officer of the Company since August 1997, as Secretary of the Company since May 1998 and as Vice President since August of 1999. From 1993 to 1997, Mr. Calerich was a business consultant specializing in accounting for public and private oil and gas producers in Denver. From 1990 to 1993, Mr. Calerich was employed as corporate Controller at a public oil and gas company in Denver. Mr. Calerich began his professional career in public accounting at Arthur Andersen & Company. Mr. Calerich is a Certified Public Accountant and earned B.S. degrees in both Accounting and Business Administration at Regis College.

Keith F. Carney has served as a Director of the Company since 1997. Since October 2001, Mr. Carney has been President of Dolomite Advisors, LLC, a manager of energy investment funds. From October 1997 until August, 2001, Mr. Carney served as Executive Vice-President of Cheniere Energy, Inc., a Houston-based natural gas company. From July 1996 until September 1997 Mr. Carney served as Chief Financial Officer of Cheniere. Mr. Carney is currently a Director of Cheniere. After earning his M.B.A. degree from the University of Denver in 1992, Mr. Carney was employed as a Securities Analyst in the oil and gas exploration/production sector with Smith Barney, Inc. Mr. Carney began his career as an exploration Geologist at Shell Oil after earning B.S. and M.S. degrees in Geology from Lehigh University.

S. L. Hutchison 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. Since 1979, Mr. Hutchison has served as Vice President and Chief Financial Officer of Victory Oil Company, an oil and gas production company based in California, and other companies in the Victory Group of Companies. Also during that period, Mr. Hutchison has served as Vice-President and Chief Financial Officer and a Director of Crail Capital, a real estate investment company that is owned by Victory Oil Company, and Victex, Inc., a real estate and oil and gas company. Mr. Hutchison also serves as Chief Financial Officer and a director of each of the Crail Johnson Foundation and the Independent Oil Producers Agency, and is the Treasurer and a director of the Los Angeles Maritime Institute. Mr. Hutchison received a Bachelor's degree in accounting from the University of Washington in 1954.

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. Since 1996, Mr. Rhodes has served as Vice President of Whittier Energy Company ("WEC"), an oil and gas investment company. 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.

Kenneth R. Berry, Jr. has served as Vice President of land since August, 1999 and as land manager for the Company since October 1997. Mr. Berry is responsible for the management of all land issues including leasing and permitting. Mr. Berry has 23 years of experience as an independent landman. 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.

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. The Company believes that during the year ended August 31, 2001, 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 upon representations and its review of copies of the Section 16(a) reports filed for the fiscal year ended August 31, 2001 on behalf of the Company's directors, officers and holders of more than 10% of the Company's common stock.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated by reference to the information to be provided in the Company's definitive proxy statement for the 2002 annual meeting of shareholders, which is to be filed within 120 days after our fiscal year end on August 31, 2001.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 is incorporated by reference to the information to be provided in the Company's definitive proxy statement for the 2002 annual meeting of shareholders, which is to be filed within 120 days after our fiscal year end on August 31, 2001.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

During the fiscal year ended August 31, 2001, there were no 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.

PART IV

ITEM 14. EXHIBITS, FINANCIAL SCHEDULES AND REPORTS ON FORM 8-K

(a)(1) and (a)(2) Financial Statements And Financial Statement Schedules

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All other schedules are omitted because the required information is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Financial Statements and Notes thereto.

(a)(3) Exhibits.

Exhibit Index

Number	Description
3.1	Articles Of Incorporation filed with the Maryland Secretary Of State on June 18, 2001.
3.2	Articles of Merger filed with the Maryland Secretary Of State on July 3, 2001 in connection with Maryland reincorporation.
3.3	Bylaws

(b) Reports On Form 8-K.

During the fourth quarter of the fiscal year ended August 31, 2001, the Company filed three Current Reports on Form 8-K dated July 5, 2001, July 16, 2001 and August 24, 2001. These events consisted of the dissemination of press releases by the Company and were reported under "ITEM 5. OTHER EVENTS".

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

Date: December 14, 2001 By: /s/ D. Scott Singdahlsen

D. Scott Singdahlsen, Chief Executive Officer

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/ D. Scott Singdahlsen D. Scott Singdahlsen	Chief Executive Officer, President and Chairman Of The Board	December 14, 2001
/s/ Keith F. Carney Keith F. Carney	Director	December 14, 2001
/s/ S. L. Hutchison S. L. Hutchison	Director	December 14, 2001
/s/ Bryce W. Rhodes Bryce W. Rhodes	Director	December 14, 2001
/s/ Andrew P. Calerich Andrew P. Calerich	Vice-President, Chief Financial Officer and Secretary	December 14, 2001

PYR ENERGY CORPORATION
(A Development Stage Company)

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INDEPENDENT AUDITOR'S REPORT

To The Board of Directors and Stockholders
PYR ENERGY CORPORATION

We have audited the accompanying balance sheets of PYR Energy Corporation (a development stage company) as of August 31, 2001 and 2000 and, the related statements of operations, stockholders' equity and cash flows for each of the three years in the period ended August 31, 2001 and cumulative amounts from inception to August 31, 2001. 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 auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits 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 financial statements referred to above present fairly, in all material respects, the financial position of PYR Energy Corporation as of August 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended August 31, 2001 and cumulative amounts from inception to August 31, 2001 in conformity with accounting principles generally accepted in the United States of America.

/s/ Wheeler Wasoff, P.C.

Wheeler Wasoff, P.C.

Denver, Colorado
November 13, 2001

PYR ENERGY CORPORATION
(A Development Stage Company)
BALANCE SHEETS
AUGUST 31, 2001 and 2000

ASSETS

	2001
CURRENT ASSETS	
Cash	$ 9,800,84
Accounts receivable	1,173,75
Prepaid expenses	74,63
Total Current Assets	11,049,22
PROPERTY AND EQUIPMENT	11,017,95
	$ 22,067,18

LIABILITIES AND STOCKHOLDERS' EQUITY

CURRENT LIABILITIES	
Accounts payable and accrued liabilities	$ 2,263,36
Current portion of capital lease obligation	--
Total Current Liabilities	2,263,36
COMMITMENTS AND CONTINGENCIES (Note 7)	
STOCKHOLDERS' EQUITY	
Preferred stock, $.001 par value; authorized 1,000,000 shares	
Series A authorized 25,000 shares; issued and outstanding 14,263 shares (2000)	--
Common stock, $.001 par value; authorized 75,000,000 shares	
Issued and outstanding 23,691,357 shares (2001) and 19,069,019 shares (2000)	23,69
Capital in excess of par value	35,214,00
Deficit accumulated during the development stage	(15,433,87
	19,803,81

$ 22,067,18

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF OPERATIONS

	Years ended August 31,			Cumu f Incep Augu
	2001	2000	1999	2
REVENUES				
Oil and gas production	$ 1,201,979	$ --	$ --	$ 1,
Interest income	422,117	165,411	116,713	
Other	--	--	--	
	1,624,096	165,411	116,713	2,
OPERATING EXPENSES				
Lease operating expenses	102,018	--	--	
Impairment, dry hole, and abandonments	13,339,911	200,000	306,369	13,
Depreciation and amortization	17,823	18,327	24,380	
General and administrative	1,306,635	929,420	743,115	3,
Interest	--	211	183,256	
	14,766,387	1,147,958	1,257,120	18,
OTHER INCOME				
Gain on sale of oil and gas prospects	--	--	--	
	(13,142,291)	(982,547)	(1,140,407)	(15,
INCOME APPLICABLE TO PREDECESSOR LLC (Note 1)	--	--	--	
NET (LOSS)	(13,142,291)	(982,547)	(1,140,407)	(15,
Less dividends on preferred stock	(62,880)	(178,621)	(50,910)	(

NET (LOSS) TO COMMON STOCKHOLDERS	$(13,205,171)	$ (1,161,168)	$ (1,191,317)	$(15,
NET (LOSS) PER COMMON SHARE BASIC AND DILUTED (Note 1)	$ (.59)	$ (.07)	$ (.11)	$
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING BASIC AND DILUTED (Note 1)	22,226,906	16,069,869	10,823,645	12,

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001

		Preferred Stock	
	Members' Equity	Shares	Amount
Inception, May 31, 1996	$ --	--	$ --
Initial member contributions - cash	5,000	--	--
Member contribution- services	12,000	--	--
Distributions to members	(24,000)	--	--
Net income	18,963		
Balance, December 31, 1996	11,963	--	--
Member contributions - cash	23,000	--	--
Member contribution - services	24,000	--	--
Distributions to members	(42,000)	--	--
Net income - January 1, 1997 to August 5, 1997	16,905	--	--
Issuance of common stock to members of PYR Energy, LLC upon merger ($.008 per share)	(33,868)	--	--
Recapitalization of shares issued by Mar prior to merger	--	--	--
Sales of common stock pursuant to private placement at $.25 per share	--	--	--
Sale of common stock pursuant to private placement at $.75 per share	--	--	--
Costs of private placements offerings	--	--	--
Net (loss) August 6, 1997 to August 31, 1997	--	--	--
Balance, August 31, 1997	--	--	--
Net (loss)	--	--	--

Balance, August 31, 1998	$ --	--	$ --

The accompanying notes are an integral part of the financial statements

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PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001
(Con't)

	Common Stock		Capital in Excess of
	Shares	Amount	Par Value
Inception, May 31, 1996	--	$ --	$ --
Initial member contributions - cash	--	--	--
Member contribution- services	--	--	--
Distributions to members	--	--	--
Net income			
Balance, December 31, 1996	--	--	--
Member contributions - cash	--	--	--
Member contribution - services	--	--	--
Distributions to members	--	--	--
Net income - January 1, 1997 to August 5, 1997	--	--	--
Issuance of common stock to members of PYR Energy, LLC upon merger ($.008 per share)	4,000,000	4,000	29,86
Recapitalization of shares issued by Mar prior to merger	1,059,804	1,060	(72
Sales of common stock pursuant to private placement at $.25 per share	2,095,000	2,095	521,65
Sale of common stock pursuant to private placement at $.75 per share	2,000,000	2,000	1,498,00
Costs of private placements offerings	--	--	(280,71
Net (loss) August 6, 1997 to August 31, 1997	--	--	--
Balance, August 31, 1997	9,154,804	9,155	1,768,08
Net (loss)	--	--	--
Balance, August 31, 1998	9,154,804	$ 9,155	$ 1,768,08

The accompanying notes are an integral part of the financial statements

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PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY (continued)
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31,
1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST
31, 1998, 1999, 2000, and 2001

	Preferred Stock	
	Shares	Amount
Balance Forward	--	$ --
Issuance of preferred stock for convertible notes	25,000	25
Unamortized convertible note financing costs	--	--
Issuance of common stock for interest on convertible debt, at $2.19 per share	--	--
Issuance of common stock warrants for financing costs	--	--
Conversion of preferred stock to common stock at $.60 per share	(2,021)	(2)
Sale of common stock pursuant to private placement for cash of $1.60 per share	--	--
Costs of private placement	--	--
Exercise of private placement warrants for cash of $2.50 per share	--	--
Issuance of common stock for property, valued at $.75 per share	--	--
Issuance of common stock for property, valued at $2.00 per share	--	--
Preferred dividends paid	--	--
Net (loss)	--	--
Balance August 31, 1999	22,979	$ 23

The accompanying notes are an integral part of the financial statements

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PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY (continued)

PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001
(Con't)

	Common Sock		Capita Excess
	Shares	Amount	Val
Balance Forward	9,154,804	$ 9,155	$ 1,76
Issuance of preferred stock for convertible notes	--	--	2,49
Unamortized convertible note financing costs	--	--	(7
Issuance of common stock for interest on convertible debt, at $2.19 per share	53,326	53	11
Issuance of common stock warrants for financing costs	--	--	5
Conversion of preferred stock to common stock at $.60 per share	336,833	337	
Sale of common stock pursuant to private placement for cash of $1.60 per share	4,375,000	4,375	6,99
Costs of private placement	--	--	(8
Exercise of private placement warrants for cash of $2.50 per share	3,125	3	
Issuance of common stock for property, valued at $.75 per share	266,666	267	19
Issuance of common stock for property, valued at $2.00 per share	218,866	219	43
Preferred dividends paid	--	--	(5
Net (loss)	--	--	
Balance August 31, 1999	14,408,620	$ 14,409	$ 11,87

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY (continued)
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001

	Preferred Stock	
	Shares	Amount

Balance Forward	22,979	$ 23
Issuance of common stock for services (valued at $4.00 per share)	--	--
Conversion of preferred stock to common stock at $.60 per share	(8,716)	(9)
Exercise of warrants for cash of $.75 per share	--	--
Exercise of private placement warrants for cash of $2.50 per share	--	--
Issuance of common stock for payment of preferred dividends (valued at $4.30 per share)	--	--
Issuance of common stock for payment of preferred dividends (valued at $5.24 per share)	--	--
Sale of common stock pursuant to private placement for cash of $3.25 per share	--	--
Cost of private placement	--	--
Exercise of common stock options	--	--
Retirement of common stock received for option exercise	--	--
Sale of common stock pursuant to private placement for cash of $3.50 per share	--	--
Issuance of common stock warrants for offering costs	--	--
Costs of private placement	--	--
Net (loss)	--	--
Balance August 31, 2000	14,263	$ 14

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY (continued)
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001
(Con't)

	Common Stock		Capital Excess o
	Shares	Amounts	Valu
Balance Forward	14,408,620	$ 14,409	$ 11,874
Issuance of common stock for services (valued at $4.00 per share)	5,000	5	1
Conversion of preferred stock to common stock at $.60 per share	1,452,597	1,452	(
Exercise of warrants for cash of $.75 per share	58,333	58	4
Exercise of private placement warrants for cash of $2.50 per share	160,938	161	40

Issuance of common stock for payment of preferred dividends (valued at $4.30 per share)	24,914	25	
Issuance of common stock for payment of preferred dividends (valued at $5.24 per share)	13,617	14	
Sale of common stock pursuant to private placement for cash of $3.25 per share	220,000	220	71
Cost of private placement	--	--	(1
Exercise of common stock options	27,500	28	2
Retirement of common stock received for option exercise	(2,500)	(3)	(1
Sale of common stock pursuant to private placement for cash of $3.50 per share	2,700,000	2,700	9,44
Issuance of common stock warrants for offering costs	--	--	11
Costs of private placement	--	--	(56
Net (loss)	--	--	
Balance August 31, 2000	19,069,019	$ 19,069	$ 22,04

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY (continued)
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001

	Preferred Stock	
	Shares	Amounts
Balance Forward	14,263	$ 14
Conversion of preferred stock to common stock	(14,263)	(14)
Exercise of warrants for cash of $.75 per share	--	--
Exercise of private placement warrants for cash of $2.50 to $4.80 per share	--	--
Issuance of common stock for payment of preferred dividends (valued at $6.40 per share)	--	--
Exercise of common stock options for cash at $.69 to $3.66 per share	--	--
Retirement of common stock received for option exercise	--	--
Sale of common stock for cash of $8.00 per share	--	--
Costs of common stock sale	--	--
Net (loss)	--	--
Balance August 31, 2001	--	$ --

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF MEMBERS'/STOCKHOLDERS' EQUITY (continued)
PERIOD FROM INCEPTION (MAY 31, 1996) TO DECEMBER 31, 1996, EIGHT MONTHS ENDED AUGUST 31, 1997 AND YEARS ENDED AUGUST 31, 1998, 1999, 2000, and 2001
(Con't)

	Common Stock		Capita Excess
	Shares	Amounts	Val
Balance Forward	19,069,019	$ 19,069	$ 22,04
Conversion of preferred stock to common stock	2,377,234	2,377	(
Exercise of warrants for cash of $.75 per share	116,667	117	8
Exercise of private placement warrants for cash of $2.50 to $4.80 per share	439,723	439	1,46
Issuance of common stock for payment of preferred dividends (valued at $6.40 per share)	9,825	10	
Exercise of common stock options for cash at $.69 to $3.66 per share	246,000	246	28
Retirement of common stock received for option exercise	(17,111)	(17)	(11
Sale of common stock for cash of $8.00 per share	1,450,000	1,450	11,59
Costs of common stock sale	--	--	(16
Net (loss)	--	--	
Balance August 31, 2001	23,691,357	$ 23,691	$ 35,21

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF CASH FLOWS

	Years Ended August 31,		
	2001	2000	1999

CASH FLOWS FROM OPERATING ACTIVITIES			
Net (loss)	$(13,142,291)	$ (982,547)	$ (1,140,4
Adjustments to reconcile net (loss) to net cash (used) by operating activities			
Depreciation and amortization	17,823	18,327	24,3
Contributed services	--	--	--
Gain on sale of oil and gas prospects	--	--	--
Impairment, dry hole and abandonments	13,339,911	200,000	306,3
Common stock issued for interest on debt	--	--	116,8
Common stock issued for services	--	20,000	--
Amortization of financing costs	--	--	26,9
Amortization of marketable securities	--	--	(20,2
Changes in assets and liabilities			
(Increase) decrease in accounts receivable	(1,173,751)	2,516	(3,0
(Increase) in prepaids	(53,801)	(6,644)	(3,4
Increase (decrease) in accounts payable	22,303	(105,802)	135,4
Other	1,946	--	10,0
Net cash (used) by operating activities	(987,860)	(854,150)	(547,2
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid for furniture and equipment	(30,757)	(4,200)	(13,0
Cash paid for oil and gas properties	1,329,468)	(5,929,267)	(3,522,9
Proceeds from sale of oil and gas properties	--	--	--
Cash paid for marketable securities	--	--	(5,090,7
Proceeds from sale of marketable securities	--	5,111,062	--
Cash received (paid) for reimbursable property costs	381,605	--	(410,0
Net cash (used) in investing activities	(10,978,620)	(822,405)	(9,036,8
CASH FLOWS FROM FINANCING ACTIVITIES			
Members capital contributions	--	--	--
Distributions to members	--	--	--
Cash from short-term borrowings	--	--	--
Repayment of short-term borrowings	--	--	--
Cash received upon recapitalization and merger	--	--	--
Proceeds from sale of common stock	11,600,000	10,165,000	7,000,0
Proceeds from sale of convertible debt	--	--	2,500,0
Proceeds from exercise of warrants	1,557,166	446,095	7,8
Proceeds from exercise of options	173,530	16,000	--
Cash paid for offering costs	(160,470)	(468,687)	(126,5
Payments on capital lease	(920)	(1,742)	(1,4
Preferred dividends paid	--	--	(50,9
Net cash provided by financing activities	13,169,306	10,156,666	9,328,8
NET INCREASE (DECREASE) IN CASH	1,202,826	8,480,111	(255,1
CASH, BEGINNING OF PERIODS	8,598,016	117,905	373,1
CASH, END OF PERIODS	$ 9,800,842	$ 8,598,016	$ 117,9

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
STATEMENTS OF CASH FLOWS (continued)
YEARS ENDED AUGUST 31, 2001, 2000 and 1999 and
PERIOD FROM INCEPTION TO AUGUST 31, 2001

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

During the years ended August 31, 2001, 2000 and 1999, the Company paid cash for interest of $0, $211 and $371 respectively, on a capital lease.

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES

During the year ended August 31, 2001, the Company issued 9,825 shares of common stock as payment of dividends on preferred stock.

During the year ended August 31, 2000, the Company issued common stock, valued at $20,000, for services; issued warrants, valued at $110,606, as partial consideration for a finders fee in connection with a private placement sale of common stock; and issued 38,531 shares of common stock as payment of dividends on preferred stock.

During the year ended August 31, 1999, the Company issued common stock, valued at $637,732, as partial consideration for oil and gas properties; issued common stock, valued at $116,822 for interest on convertible debt; and issued warrants, valued at $56,833, as partial consideration for a finders fee in connection with the sale of convertible debt.

During the year ended August 31, 1998, the Company entered into a capital lease obligation of $5,195 for office equipment.

During 1996 and 1997 the President of the Company performed services for PYR LLC valued at $12,000 and $24,000, respectively. The value of these services was charged to members' equity as a non-cash capital contribution.

In August 1997, 4,000,000 shares of common stock were issued to the members of PYR Energy, LLC ("PYR LLC") in exchange for 100 percent of the ownership interests in PYR LLC, for which the net members' equity in PYR LLC was $33,868. These shares were issued pursuant to a plan of reorganization and merger effective August 6, 1997 (Note 1).

The accompanying notes are an integral part of the financial statements

PYR ENERGY CORPORATION
(A Development Stage Company)
Notes to Financial Statements

NOTE 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 State of California and the Rocky Mountain region of the United States. As of August 31, 2001, the Company is considered a development stage company as defined by Statement of Financial Accounting Standards No. 7 (SFAS 7).

The Company's predecessor, Mar Ventures Inc. ("Mar"), was incorporated under the laws of the State of Delaware on March 27, 1996 for the purpose of producing and marketing traditional television programming and marketing its film library. Mar was a public company which had no significant operations as of July 31, 1997. On August 6, 1997 Mar acquired all the interests in PYR Energy LLC ("PYR LLC") (a Colorado limited liability company organized on May 31, 1996), a development stage company as defined by SFAS No. 7. PYR LLC, an independent exploration company, was engaged in the acquisition of oil and gas properties for exploration and exploitation in the Rocky Mountain region and California. Effective August 6, 1997, Mar transferred to its former president substantially all its assets and liabilities that were related to its film library operations.

Upon completion of the acquisition of PYR LLC by Mar, PYR LLC ceased to exist as a separate entity. Mar remained as the legal surviving entity and, effective November 12, 1997, Mar changed its name to PYR Energy Corporation. For financial reporting purposes, the business combination was accounted for as an additional capitalization of Mar (a reverse acquisition with PYR LLC as the acquirer). The operations of PYR LLC are the only continuing operations of the Company. Effective July 02, 2001, the Company was reincorporated in Maryland through the merger of the Company into a wholly owned subsidiary, PYR Energy Corporation, a Maryland corporation.

The Company is an exploration stage oil and gas company. The Company's efforts, since August 1997, have consisted of financing activities and the acquisition of unproven properties and related seismic data. The Company has entered into participation and farm-in agreements with industry partners on certain of its properties pursuant to which these partners have acquired, for cash, interests in the Company's properties. During the year ended August 31, 1998, drilling of two test wells was commenced, with one well being plugged and abandoned and the other suffering a blowout. During the years ended August 31, 1999 and 2000, the Company continued its acquisition of unproven properties and related seismic data with industry partners, and participated in exploration of the properties, including the drilling of exploratory wells. During the year ended August 31, 2001, initial production of oil and gas commenced from the Company's East Lost Hills prospect. Although initial production resulted in test revenue from oil and gas sales of $1,201,979 being earned through August 31, 2001, a reserve report prepared as of August 31, 2001 by an independent petroleum engineering firm concluded that reserves from the Company's producing properties are not economic to produce. (See Notes 2 and 3). Accordingly, based on the ceiling test limitation required for oil and gas companies utilizing the full cost method of accounting, the Company recognized an impairment of $13,339,911 on its oil and gas properties at August 31, 2001.

As of the nine months period ended May 31, 2001, the Company disclosed in it's Form 10QSB filed with the Securities and Exchange Commission that it was no longer a development stage company. This was based on the Company's assessment that it had commenced principal operations from its oil and gas activities due to initial production from its East Lost Hills prospect. Based on the results of the reserve report prepared as of August 31, 2001, the Company has determined that it is still a development stage Company as defined by SFAS 7.

PYR ENERGY CORPORATION
(A Development Stage Company)
Notes to Financial Statements

NOTE 1 - ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

PROPERTY AND EQUIPMENT

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

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, which constitutes one cost center. 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. A reserve report prepared as of August 31, 2001 by an independent petroleum engineering firm concluded that reserves from the Company's producing properties are not currently economic to produce and, therefore, at August 31, 2001, the Company had no proved 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. The Company has not accrued costs for future site restoration, dismantlement and abandonment costs related to oil and gas properties because the Company estimates that such costs will be offset by the salvage value of the equipment sold upon abandonment of such properties.

At August 31, 2001, the ceiling test limitation resulted in the Company's recognizing an impairment expense of $13,339,911 on its oil and gas properties. At August 31, 2000 and 1999, the Company had determined that an impairment loss of $200,000 and $285,229, respectively, on evaluated oil and gas properties be recognized.

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.

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.

NOTE 1 - ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

INCOME TAXES

The Company has adopted the provisions of SFAS No. 109, "Accounting for Income Taxes". 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.

At August 31, 2001, the Company had a net operating loss carryforward of approximately $14,100,000 that may be offset against future taxable income through 2021. These carryforwards are subject to review by the Internal Revenue Service.

The Company has fully reserved the $3,085,000 tax benefit of operating loss carryforwards, by a valuation allowance of the same amount, because the likelihood of realization of the tax benefit cannot be determined. Of the total tax benefit, $1,700,000 is attributable to 2001.

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 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. Price declines reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves).

(LOSS) PER SHARE

(Loss) per common share is computed based on the weighted average number of common shares outstanding during each period. Common shares issued to the members of PYR LLC upon completion of the merger are considered outstanding for all periods presented. Convertible equity instruments, such as stock options and warrants, are not considered in the calculation of net loss per share as their inclusion would be antidilutive.

PYR ENERGY CORPORATION
(A Development Stage Company)
Notes to Financial Statements

NOTE 1 -ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

SHARE BASED COMPENSATION

In October 1995, SFAS No. 123, "Accounting for Stock-Based Compensation", was issued. This standard defines a fair value based method of accounting for an employee stock option or similar equity instrument. This statement gives entities a choice of recognizing related compensation expense by adopting the new fair value method or to continue to measure compensation using the intrinsic value approach under Accounting Principles Board (APB) Opinion No. 25. The Company has elected to utilize APB No. 25 for measurement; and will, pursuant to SFAS No. 123, disclose supplementally the pro forma effects on net income and earnings per share of using the new measurement criteria.

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 below, "Concentration of Credit Risks".

NEW TECHNICAL PRONOUNCEMENTS

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS 141 "Business Combinations" and SFAS 142 "Goodwill and Other Intangible Assets". SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for under the purchase method. For all business combinations for which the date of acquisition is after June 30, 2001, SFAS 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill and requires unallocated negative goodwill to be written off immediately as an extraordinary gain rather than deferred and amortized. SFAS 142 changes the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives

will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for intangible assets with finite lives will no longer be limited to forty years. The Company does not believe that the adoption of these statements will have a material effect on its financial position, results of operations, or cash flows.

In June 2001, the FASB also approved for issuance SFAS 143, "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of assets retirement cost to expense, (4) subsequent measurement of the liability, and (5) financial statement disclosure. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The adoption of SFAS 143 is not expected to have a material effect on the Company's financial position, results of operations, or cash flows.

NOTE 1 -ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

In August 2001, the FASB also approved SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets ." SFAS 144 replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discounted operations, and replaces the provisions of APB Opinion No. 30, "Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business," for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discounted operations. Therefore, discounted operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally, are to be applied prospectively. The adoption of SFAS 144 is not expected to have a material effect on the Company's financial position, results of operations, or cash flows.

FAIR VALUE

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

CONCENTRATION OF CREDIT 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's receivables are from oil and gas sales due from one purchaser, a major U.S. oil and gas company. Based on the credit worthiness of this Fortune 500 Company, the Company believes that credit risk associated with receivables is nominal.

RECLASSIFICATION

Certain reclassifications have been made to 2000 and 1999 amounts to conform to the 2001 presentation.

NOTE 2 - ACCOUNTS RECEIVABLE AND ACCOUNTS PAYABLE

Accounts receivable at August 31, 2001 includes $1,173,155 of net revenue due from operator for oil and gas sales for the initial period from February to August 2001. The Company has not received any payments for production from the operator, and the joint operating agreement underlying the East Lost Hills prospect does not provide for the Company to offset the receivable for oil and gas revenue against amounts due to the operator. The Company believes that the operator is legally responsible to remit payment. Until the Company receives payment, management intends to offset payments due to the operator for cash calls and other liabilities in an amount equal to the revenue due. Although the joint operating agreement provides that the operator can charge interest on past due cash calls and billings, no interest has been charged to the Company.

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NOTE 2 - ACCOUNTS RECEIVABLE AND ACCOUNTS PAYABLE (continued)

As of August 31, 2001, the Company's liability due to the operator exceeded accounts receivable for oil and gas sales by $774,037, including $456,585 for drilling costs not billed as of August 31, 2001.

Accounts payable at August 31, 2001 and 2000 are as follows:

	2001	2000
Due to operator	$ 1,947,192	$ --
Trade payables	254,213	165,289
Ad Valorem Tax	61,963	--
	$2,263,368	$ 165,289

NOTE 3 - PROPERTY AND EQUIPMENT

Property and equipment at August 31, 2001 and 2000 consisted of the

following:

	2001
Oil and gas properties, full cost method	
Unevaluated costs, not subject to amortization or ceiling test	$10,977,317
Evaluated costs	13,825,140
Furniture and equipment	118,208
Asset under capital lease	--
	24,920,665
Less accumulated depreciation, amortization, and impairment	(13,902,710)
	$11,017,955

Information relating to the Company's costs incurred in its oil and gas operations during the years ended August 31, 2001, 2000, and 1999 is summarized as follows:

	2001	20
Property acquisition costs, unproved properties	$ 4,114,449	$ 1,3
Exploration costs	2,448,990	4,6
Development costs	6,460,201	
	$13,023,640	$ 5,9

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.

NOTE 3 - PROPERTY AND EQUIPMENT (continued)

During the year ended August 31, 2001, the Company earned its initial revenues from its oil and gas producing activities. A reserve report prepared as of August 31, 2001 by an independent petroleum engineering firm concluded that reserves from the Company's producing properties are not economic to produce, and, therefore, at August 31, 2001, the Company had no proved reserves. Therefore, the Company has recorded an impairment of $13,339,911 based on the ceiling test limitation. Depreciation, depletion and amortization of $68,456 previously recorded through May 31, 2001 has been reclassified as a component of the impairment charge at August 31, 2001. The Company recorded impairment losses on undeveloped oil and gas

properties of $200,000 and $285,229 for the years ended August 31, 2000 and 1999, respectively. During the year ended August 31, 1999, the Company abandoned properties with a carrying cost of $21,140

At August 31, 2001, 2000, and 1999, accumulated charges to impairment were $13,825,140, $485,229 and $285,229, respectively.

Depreciation expense for the years ended August 31, 2001, 2000 and 1999 was $17,823, $18,327, and $24,111, respectively.

In November 2000, the Company purchased from a privately held non-related entity an additional 1.544% interest in the East Lost Hills project. At August 31, 2001, the Company had a 12.119% interest in East Lost Hills.

NOTE 4 - CONVERTIBLE NOTES PAYABLE

In November 1998, the Company completed the sale of $2,500,000, 10% convertible notes, due October 1999. The notes were convertible into an aggregate 25,000 shares of a newly designated Series A Preferred Stock of the Company. The Company obtained stockholder approval for authorization of the Series A Preferred Stock and, in April 1999, all notes were converted to Series A Preferred Stock. Accrued interest due as of the date of conversion of $116,822 was paid by the issuance of 53,326 shares of common stock, valued at $2.19 per share, the non-discounted trading price of the Company's common stock at the transaction date. In conjunction with the sale of $1,500,000 of the notes, the Company paid a finder's fee consisting of $45,000 and warrants to purchase 175,000 shares of the Company's common stock at an exercise price of $.75 per share for a period of five years. The warrants were valued at $56,833.

NOTE 5 - STOCKHOLDERS' EQUITY

PREFERRED STOCK

In April 1999, the stockholders of the Company approved an amendment to the Certificate of Incorporation wherein the Company was authorized to issue 1,000,000 shares of preferred stock, with a par value of $.001 per share. The Board of Directors authorized the designation of a "Series A Preferred Stock," consisting of 25,000 shares, face value of $100 per share, 10% cumulative dividend payable in cash or shares of common stock on January 1 and July 1 of each year. Holders of Series A Preferred Stock receive preference in the event of any liquidation, dissolution or winding up of the Company. The shares of Series A Preferred Stock were convertible into shares of common stock of the Company at an initial conversion price of $.60 per share. No beneficial interest has been accrued to the preferred stockholders as the conversion price of $.60 per share was substantially in excess of the fair market value of the common shares as of the transaction date.

NOTE 5 - STOCKHOLDERS' EQUITY (continued)

In April 1999, the holders of convertible notes (Note 5) converted the notes to 25,000 shares of Series A Preferred Stock. As of August 31, 2001,

all shares of Series A Preferred Stock were converted to 4,166,664 shares of common stock at the initial conversion price of $.60 per share.

COMMON STOCK

Effective August 6, 1997 Mar completed a merger with PYR LLC (Note 1). In conjunction with the merger, the members of PYR LLC received 4,000,000 shares of common stock of Mar. These shares were recorded at the net members' equity of PYR LLC as of that date of $33,868. The 1,059,804 Mar shares outstanding as of the date of merger were recapitalized to the net assets of Mar of $336. For financial statement reporting purposes, this transaction was treated as a reverse acquisition whereby PYR LLC was considered the surviving and reporting entity. For legal purposes, however, Mar remained as the surviving entity; therefore, the capital structure of the Company was accordingly restated.

In July 1997, the Company completed the sale of common stock and warrants pursuant to a private placement as follows:

- 2,095,000 units, at a price of $.25 per unit, consisting of 2,095,000 shares of common stock, warrants to purchase 1,047,500 shares of common stock at an exercise price of $1.25 per share before October 31, 1997, and warrants to purchase 1,047,500 shares of common stock at an exercise price of $1.75 per share before January 31, 1998. Subsequent to the offering, each of the warrant expiration dates was extended one or more times, and all the warrants ultimately expired without having been exercised.

In August 1997, the Company completed the sale of common stock and warrants pursuant to a private placement as follows:

- 2,000,000 units, at a price of $.75 per unit, consisting of 2,000,000 shares of common stock, warrants to purchase 1,000,000 shares of common stock at an exercise price of $1.25 per share before October 31, 1997, and warrants to purchase 1,000,000 shares of common stock at an exercise price of $1.75 per share before January 31, 1998. Subsequent to the offering, each of the warrant expiration dates was extended one or more times, and all the warrants ultimately expired without having been exercised.

Proceeds from these offerings were $523,750 and $1,500,000, respectively, before costs of the offerings of $280,711.

In May 1999, the Company completed the sale of 437,500 units of common stock and warrants pursuant to a private placement at a price of $16 per unit. Each unit consisted of 10 shares of common stock and one warrant to purchase one share of common stock at an exercise price of $2.50 per share for a period of five years. The Company may repurchase the warrants for $.001 per warrant at any time after the weighted average trading price of the Company's common stock has been at least $6.00 per share for a 45-day period. Proceeds from the offering were $7,000,000, before costs of the offering of $83,155.

During the year ended August 31, 1999, the Company issued shares of common stock, valued at non-discounted trading market price as of the date of the transaction, in conjunction with the assignment to the Company of certain undeveloped oil and gas prospects located in California as follows:

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NOTE 5 - STOCKHOLDERS' EQUITY (continued)

- 266,666 shares, valued at $.75 per share, as full consideration for property received.
- 218,866 shares, valued at $2.00 per share, as partial consideration for property received.

In May 2000, the Company completed the sale of 22,000 units of common stock and warrants pursuant to a private placement at a price of $32.50 per unit. Each unit consisted of 10 shares of common stock and one warrant to purchase one share of common stock at an exercise price of $4.25 per share for a period of three years. The Company may repurchase the warrants for $.001 per warrant at any time after the weighted average trading price of the Company's common stock has been at least $7.50 per share for a 30 day period. Proceeds from the offering were $715,000, before costs of the offering of $11,857.

In August 2000, the Company completed the sale of 540,000 units of common stock and warrants pursuant to a private placement at a price of $17.50 per unit. Each unit consisted of five shares of common stock and one warrant to purchase one share of common stock at an exercise price of $4.80 per share for a period of three years. The Company may repurchase the warrants for $.001 per warrant at any time after the weighted average trading price of the Company's common stock has been at least $10.00 per share for a 30 day period. Proceeds from the offering were $9,450,000, before costs of the offering of $567,436, which included warrants valued at $110,606.

During the year ended August 31, 2000, the Company issued 5,000 shares of common stock for services, valued at the non-discounted trading market price as of the date of the transaction of $20,000 ($4.00 per share).

During the year ended August 31, 2001, the Company sold 1,450,000 shares of common stock pursuant to a shelf registration at a price of $8.00 per share. Proceeds from the offering were $11,600,000 before costs of $160,470.

WARRANTS

In 1999, the Company issued warrants to purchase 175,000 shares of common stock at an exercise price of $.75 per share through October 26, 2003 as partial consideration for a finder's fee in conjunction with the private placement of convertible notes. The warrants are valued at $56,833, using the Black-Scholes option pricing model. In May 1999, in conjunction with the sale of 437,500 units of common stock and warrants as described above, the Company issued warrants to purchase 437,500 shares of common stock at an exercise price of $2.50 through May 14, 2004.

In 2000, the Company issued warrants to purchase 70,875 shares of common stock at an exercise price of $5.50 per share through July 31, 2003 as partial consideration for a finder's fee in conjunction with the private placement of common stock. The warrants are valued at $110,606, using the Black-Scholes option pricing model. In May 2000, in conjunction with the sale of units of common stock and warrants as described above, the Company issued warrants to purchase 22,000 shares of common stock at an exercise price of $4.25 through May 19, 2003. In August 2000, in conjunction with the sale of units and common stock, the Company issued warrants to purchase 540,000 shares of common stock at an exercise price of $4.80 through July

31, 2003.

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NOTE 5 - STOCKHOLDERS' EQUITY (continued)

At August 31, 2001, the status of outstanding warrants is as follows:

Issue Date	Shares Exercisable	Exercise Price	Expiration Date
July 31, 2000	395,714	$4.80	July 31, 2003
August 1, 2000	70,875	$5.50	July 31, 2003

At August 31, 2001, the per share weighted average exercise price of outstanding warrants was $4.91 per share and the weighted average remaining contractual life was 1.9 years.

NOTE 6 - STOCK OPTION PLAN

Under two stock option plans, options to purchase common stock may be granted until 2010. 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 2,500,000 shares of common stock for these plans. At August 31, 2001 and 2000, options to purchase 1,000,000 and 300,000 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	Wei Fa
Options Outstanding- September 1, 1998 (37,000 exercisable)	246,000	$1.46	
Expired	(10,000)	$1.28	
Granted	585,000	$1.10	
Options Outstanding- August 31, 1999 (149,000 exercisable)	821,000	$1.20	
Granted	379,000	$3.06	
Exercised	(27,500)	$ .96	
Options Outstanding- August 31, 2000 (447,500 exercisable)	1,172,500	$2.12	
Granted	300,000	$6.10	
Exercised	(246,000)	$1.17	

Options Outstanding- August 31, 2001 (537,333 exercisable)	1,226,500	$3.31

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NOTE 6 - STOCK OPTION PLAN (continued)

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 assumptions used:

	2001	2000	1999
Expected option life-years	5	2-5	3-5
Risk-free interest rate	5.75%	5.50%	5.50%
Dividend yield	0	0	0
Volatility	68-75%	71-81%	25-161%

At August 31, 2001, the number of options exercisable was 537,333, the weighted average exercise price of these options was $2.27, the weighted average contractual life of the options was 4.59 years and the exercise price was $.69 to $4.40 per share.

The Company has adopted the disclosure-only provisions of SFAS No. 123. Had compensation cost for the Company's stock option plan been determined based on the fair value at the grant date consistent with the provisions of SFAS No. 123, the Company's net loss and loss per share for 2001, 2000, and 1999 would have been increased to the pro forma amounts indicated below:

	2001	
Net (loss) applicable to common stockholders - as reported	$ (13,205,171)	$ (
Net (loss) applicable to common stockholders - pro forma	$ (13,632,412)	$ (
(Loss) per share - as reported	$ (.59)	$
(Loss) per share - pro forma	$ (.61)	$

NOTE 7 - COMMITMENTS AND CONTINGENCIES

The Company has entered into a non-cancelable lease, as amended, for office facilities. Minimum payments due under this lease are as follows:

Year ending August 31,	
2002	$95,975
2003	95,975

2004	95,975

Rent expense was $58,988, $41,036 and $40,816 for the years ended August 31, 2001, 2000, and 1999, respectively.

In conjunction with the Company's working interests in undeveloped oil and gas prospects, the Company must pay approximately $1,498,000 in delay rentals and other costs during the fiscal year ending August 31, 2002 to maintain the right to explore these prospects.

The Company may be subject to various possible contingencies which are derived primarily from interpretations of federal and state laws and regulations affecting the oil and gas industry. Although management believes it has complied with the various laws and regulations, new rulings and interpretations may require the Company to make adjustments.

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NOTE 8 - SEGMENT REPORTING

In June 1997, SFAS No. 131, "Disclosure about Segments of an Enterprise and Related Information", was issued, which amends the requirements for a public enterprise to report financial and descriptive information about its reportable operating segments. Operating segments, as defined in the pronouncement, are components of an enterprise about which separate financial information is available and that are evaluated regularly by the Company in deciding how to allocate resources and in assessing performance. The financial information is required to be reported on the basis that is used internally for evaluating segment performance and deciding how to allocate resources to segments.

The Company has one reportable segment, oil and gas exploration and production. The Company has concentrated its oil and gas acquisition and exploration activities in the western United States, primarily in California and the Rocky Mountain region. All significant activities in this segment have been with industry partners.

During 2001, initial production commenced on the Company's East Lost Hills Prospect in California. Results of operations for oil and gas operations in 2001 are as follows:

Revenues	
Oil and gas sales	$ 1,201,979
Expense	
Lease operating expense	40,055
Ad Valorem Taxes	61,963
Impairment	13,339,911
	13,441,929
(Loss) from oil and gas operations	$ (12,239,950)

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All sales of oil and gas were made to one customer.

No depletion has been recorded on oil and gas properties. Based on the ceiling test limitation as of August 31, 2001, the Company recorded an impairment against its entire amortizable cost pool. (See Note 3).

NOTE 9 - COMPREHENSIVE INCOME

There are no adjustments necessary to net (loss) as presented in the accompanying statements of operations to derive comprehensive income in accordance with SFAS No. 130, "Reporting Comprehensive Income."

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NOTE 10 - QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended August 31, 2001 and 2000:

	Three Months Ended			
2001	11/30/00	2/28/01	5/31/01	8/31/01
Revenues	$ 111,128	$ 309,566	$ 965,155	$ 238,247
Operating expenses				
Lease operating expenses	--	3,052	78,005	20,961
Impairment	--	--	--	13,339,911
Depreciation and amortization	4,098	4,843	5,507	3,375
General and administrative	254,248	320,781	370,021	361,585
	258,346	328,676	453,533	13,725,832
Net (Loss) Income	$ (147,218)	$ (19,110)	$ 511,622	$(13,487,585)
Net Loss per common share				
Basic and diluted	$ (.007)	$ (.001)	$ .022	$ (.569)

In the quarter ended August 31, 2001, the Company recorded an impairment of $13,339,911 on its oil and gas properties due to a ceiling test limitation. Included in the impairment is a reclassification of depletion originally recorded on oil and gas properties of $16,035 and $52,421 for the quarters ended February 28, 2001 and May 31, 2001, respectively.

	Three Months Ended			
2000	11/30/99	2/28/00	5/31/00	8/31/00

Revenues	$ 56,842	$ 27,447	$ 21,226	$ 59,896
Operating expenses				
Impairment	--	--	--	200,000
Depreciation and amortization	4,558	4,699	4,581	4,489
Interest	66	55	59	31
General and administrative	217,845	263,993	202,917	244,665
	222,469	268,747	207,557	449,185
Net (Loss)	$ (165,627)	$ (241,300)	$ (186,331)	$ (389,289)

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