PYR ENERGY CORP
Form 10-K/A
December 30, 2002

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

FORM 10-K/A1*

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended August 31, 2002

[ ] 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 filing 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 27, 2002, the registrant had 23,701,357 common shares outstanding, and the aggregate market value of the common shares held by non-affiliates was approximately $2,864,000**. This calculation is based upon the closing sale price of 31 cents per share on December 27, 2002.

* This Amendment is being filed to include the information required by Part III, Items 11 and 12. For the convenience of the reader, we are filing the entire report in this amendment although the only changes from our Form 10-K filed on November 29, 2002 are to this cover page and the addition of Part III, Items 11 and 12.

** Without asserting that any of the issuer's directors or executive officers, or the entities that own 3,113,923 and 3,634,000 shares of common stock are affiliates, the shares of which they are beneficial owners have been deemed to be owned by affiliates solely for this calculation.

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PART I

ITEM 1. and ITEM 2. 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, 2002, 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 2002

Property Impairment

During the fiscal year ended August 31, 2002, the Company recognized property impairments totaling $11,723,000 in conjunction with its capitalized oil and gas properties. This non-cash accounting charge includes the remaining capitalized balance at the Company's East Lost Hills project of $11,669,000, which includes drilling and completion costs as well as land, geological and geophysical costs. The remaining amount of the impairment includes capital costs associated primarily with a project that the Company has in the Denver Basin of Colorado. See below, "--Drilling Activities". As a result of this write-down, the Company reported a net loss for the year of $13,129,828. 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, 2002, our East Lost Hills project was subject to continued setbacks and delays. Although the 1998 blow-out of the original test well, the Bellevue #1-17, evidenced high volumes and deliverability of hydrocarbons, the project has still not established meaningful commercial production.

Berkley Petroleum Inc., a wholly owned subsidiary of Anadarko Petroleum

Corporation, the operator at East Lost Hills, has informed the participant group that it no longer intends to participate in additional operations at East Lost Hills. We are also aware of ongoing litigation between the operator and one of

the participants, and feel that this litigation has had a detrimental impact on the project and may have contributed to lack of progress in moving the project forward. In addition, certain leaseholds in the project have expired or will expire in the near future.

We have continued to evaluate our ongoing participation in the East Lost Hills project. Although we do not believe that we have adequately evaluated the Temblor potential at East Lost Hills, the historical cost structure of operations and the ongoing uncertainties make it very difficult to continue to participate in this project. We will seek to limit capital expenditures at East Lost Hills until such a point in time as many of the ongoing problems associated with the play are mitigated. There is no assurance that additional operations will occur at East Lost Hills. If additional operations are proposed, we will carefully evaluate to what extent, if any, we will participate in those operations.

During fiscal 2002, we participated in three additional wells at East Lost Hills that were proposed and approved by the participant group in fiscal 2001. Two of these wells, the ELH #4 and the ELH #9, are operated by Berkley Petroleum Inc. 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 with the ELH #9 well located approximately six miles southeast of the ELH #1 well.

The ELH #4 well was drilled and completed to a depth of approximately 20,500 feet. Although the well flowed natural gas and liquid hydrocarbons upon initial production testing, we believe that mechanical difficulties related to the influx of wellbore debris has prevented an adequate and full evaluation of the reservoir potential. During initial production testing of the ELH #4, coil tubing was used to attempt to clean out debris in the wellbore. During these clean-out operations, a portion of the coil tubing separated and became stuck in the wellbore. Retrieval operations have not been initiated, and it is uncertain whether or not the coil tubing can be removed from the wellbore. The well is currently shut-in. Although the participant group has not approved or consented, the operator has formally proposed to plug and abandon the well.

The ELH #9 well was drilled and completed to a depth of approximately 20,100 feet. Initially, the well was production tested in the Kreyenhagen shale underlying the Temblor formation. Non-commercial hydrocarbons were encountered and tested from this zone, and the participants agreed to move up hole and test the lower Temblor section. These zones were perforated by wireline and limited production of hydrocarbons were encountered. We believe that the perforation and testing methodology may have been inadequate to fully evaluate the reservoir potential and that the production results are inconclusive. This well is currently shut-in. Although the participant group has not approved or consented, the operator has formally proposed to plug and abandon the well.

The third well, the AERA Energy LLC #1-22 NWLH, located approximately 3.5 miles northwest of the ELH #1 well, was drilled to a total depth of 20,457 feet. The well encountered hydrocarbon shows and gas flow from several zones in the Temblor and casing has been installed in preparation for production testing. We have determined to prioritize our financial resources on other prospects, and have elected to non-consent the completion and production testing operations. We participated in the drilling of this well through a pooling arrangement at a 4.04% working interest.

Funding and Financing

On May 24, 2002, we received $6 million in gross proceeds from the sale of convertible notes due May 24, 2009. These notes call for semi-annual interest payments at an annual rate of 4.99% and are convertible into shares of common stock at a conversion price of $1.30 per share. The interest can be paid in cash or added to the principal amount at the discretion of the Company. The notes were issued to three investment funds pursuant to exemptions from registration under Section 3(b) and/or 4(2) of the Securities Act of 1933, as amended. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our August 31, 2002 balance sheet.

During the fiscal year ended August 31, 2002, we entered into an agreement with Stonington Corporation regarding the retention of Stonington to provide general corporate advisory services and to act as an agent and financial advisor in connection with raising project financing for the exploration and development of certain exploration projects we have in the San Joaquin Basin of California and the Rocky Mountains. We do not intend to sell additional equity in order to finance the drilling of exploration wells, but intend to establish a separate entity that will purchase a portion of our working interests in these projects.

Markets and Major Customers

Sales of production from our ownership interest in the ELH #1 well at East Lost Hills to ChevronTexaco accounted for all of our revenues. These revenues currently are accruing at approximately $10,000 per month net to our interest. 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. If we are unable to dispose of produced water at the ChevronTexaco water disposal facility and if we are not successful in finding an alternative disposal method, we may not be able to dispose of water and, therefore could not produce and sell natural gas.

Employees and Office Space

At August 31, 2002, we had seven full time employees. We believe that our relationship with our employees is satisfactory. None of our employees are covered by a collective bargaining agreement. We lease approximately 3,800 square feet of office space in Denver, Colorado for our 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:

- Carefully evaluate to what extent, if any, we will continue to participate in operations at East Lost Hills. The East Lost Hills project has been extremely time, labor and finance intensive. Although we feel there is potential for significant gas reserves, meaningful production has not been established. Because of the current cost structure, continual cost overruns, the lack of a set direction for development and the fragmentation of the participant group, additional operations may not occur. Even in the event additional operations are proposed, we may elect not to participate in additional operations.

- Initiate Exploration Drilling on Our Other Projects. 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 and Bulldog prospects, which are large target reserve, deep Temblor gas prospects located to the northwest of our East Lost Hills acreage, and our Blizzard prospect which is a light oil Stevens target. In the Rocky Mountains, our most notable projects are Cumberland and Mallard, located in southwestern Wyoming, and our Montana Foothills project. In order to be able to drill initial test wells in these projects, we are in the process of establishing a drilling fund and intend to sell a portion of our working interests in these projects to the drilling fund in exchange for a carried working interest in initial test wells.

  By combining participation of the drilling fund with potential industry partners, we expect to commence drilling exploration wells in up to five of these projects during calendar 2003.

- 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 combined with recent discoveries of hydrocarbons at depth, 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 the 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. The Bellevue #1-17R well production tested nominal amounts of hydrocarbons and is temporarily shut-in awaiting a decision to connect to commercial production facilities.

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 were installed and, on February 6, 2001, we commenced commercial production of natural gas and liquid hydrocarbons from this well. Production from this well continued throughout fiscal 2002.

Since shortly after commencing production on February 6, 2001, the production from the ELH #1 well has been constrained by 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 145 mmcfe, averaging approximately 1.6 mmcfe per day. Water production during this period averaged approximately 6,175 barrels per day.

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 20,500 feet on January 17, 2002. After installing final casing, the operator released the drilling rig and shut in the well. During July 2002, the Kreyenhagen and lower Temblor zones were perforated via wireline for production testing. The well did flow nominal amounts of natural gas and liquid hydrocarbons along with debris and water. Because the rig had been released and removed, the operator brought in a coil tubing unit to attempt to clean out the debris from the wellbore. During this operation, a portion of the coil tubing separated from the assembly and became lodged in the wellbore. It is uncertain whether or not the component of coil tubing can be retrieved. The well is currently shut-in and although the participant group has not consented or otherwise agreed, the operator has formally proposed plugging this well.

The ELH #9 well, located approximately six miles southeast of the ELH #1 well, commenced drilling operations on July 17, 2001. On April 10, 2002, the well reached total depth of approximately 21,100 feet. Final casing was installed and the operator released the drilling rig on April 27, 2002. During July 2002, the Kreyenhagen zone was perforated via wireline for production testing. This testing resulted in delivery of non-commercial volumes of hydrocarbons and attempts to stimulate the test zones were unsuccessful. The lower Temblor was then perforated for production testing. During production testing, the well flowed nominal amounts of hydrocarbons, water and debris resulting in plugging of perforations and the wellbore. Coil tubing was used to clean out the debris and further testing resulted in deliverability of hydrocarbons in nominal amounts. Due to the perforation and testing methods used, we view these production tests as inconclusive and do not reflect full evaluation of the lower Temblor potential. Although there may be additional productive Temblor zones above the lower Temblor, additional testing has not been proposed. The operator has formally proposed the plugging of this well, however the participants have not yet consented or otherwise agreed to this proposal.

During fiscal 2002, we participated in the drilling of a third well 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. We participated in the drilling of this well, operated by Aera Energy LLC, through a pooling arrangement at a 4.04% working interest. On August 18, 2002, this well reached total depth of 20,457 feet. The participants intend to complete the well for production testing, however we have been notified by the operator that certain participants do not currently have the financial ability to proceed with the completion and are attempting to raise additional funds or bring in additional participants. Since late August 2002, the drilling rig has remained on location on standby rate in anticipation of the commencement of completion operations. Because we have determined to prioritize our financial resources on other prospects, we have notified the operator of our non-consent election in the completion of this well.

Pyramid Power Prospect. In April 1999, we purchased a working interest in the Pyramid Power deep natural gas exploration project in the San Joaquin Basin. This project is outside the East Lost Hills joint venture area. The initial test well, located in Section 9, T25S-R18E, commenced drilling on November 22, 2001. On July 17, 2002, the well reached total depth of 20,465 feet. Upon running final casing, the rig was released. Berkley Petroleum Inc., a wholly owned subsidiary of Anadarko Petroleum Corporation was operator of the well during drilling. Upon release of the rig, Oxy Lost Hills Inc. ("Oxy") took over as operator and Oxy will operate the completion and production testing of this well. We originally owned a working interest in this project of 3.75%, but have committed to assign 25% of that interest to Oxy. The new working interest of 2.81% continues to be carried through the tanks in this initial test well. The participants at Pyramid Power jointly control approximately 16,100 gross and 14,700 net acres over the prospect.

Wedge Prospect. This is a seismically identified Temblor prospect located northwest of and adjacent to the East Lost Hills deep gas discovery. During the first fiscal quarter of 2001, we acquired approximately 17 miles of proprietary, high effort 2D seismic data and combined this data with existing 2D seismic data in order to refine what we interpret as the up-dip extension of the East Lost Hills structure. Our seismic interpretation shows that the same trend at East Lost Hills extends approximately ten miles 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 12,100 gross and approximately 11,600 net acres here. Our approach is to sell down our working interest and retain a 25% to 50% working interest in this prospect.

Bulldog Prospect. This project is a 2D seismically identified natural gas and condensate prospect located adjacent to the giant Kettleman North Dome field in the San Joaquin Basin. This prospect can be best characterized as a classic footwall fault trap, similar to the many known footwall fault trap accumulations that have produced significant quantities of hydrocarbons throughout the San Joaquin basin. We currently control approximately 15,600 gross and approximately 15,100 net acres here. We expect to sell down our working interest in this project and retain a 25% to 50% working interest in the prospect acreage and in a 14,000 foot test well we expect to drill during calendar 2003.

Rocky Mountain Exploration

Montana Foothills Project. This extensive natural gas exploration 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 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 belief that this test well was drilled based upon a misleading seismic image and was located significantly off-structure.

We currently control approximately 241,800 gross and 226,300 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% and 40%.

Cumberland Project. The Cumberland project, located within the Overthrust Belt of southwest Wyoming, is a gas-condensate exploration prospect in Uinta County, Wyoming. Cumberland is at the northern end of the historically productive Nugget trend on the hangingwall of the Absaroka thrust fault. The prospect lies along trend of and just north of Ryckman Creek field, which was discovered in 1975.

The Cumberland prospect can be best characterized as a classic hangingwall anticlinal trap, similar to the many known Nugget sandstone accumulations that have produced significant quantities of hydrocarbons from Pineview to Ryckman Creek. The Cumberland culmination is the result of structural deformation related to back-thrusting off of the Absaroka thrust, a similar geometry to that exhibited at East Painter Reservoir field.

We currently control approximately 5,400 gross and net acres in the project and expect to sell down our working interest to between 25% and 50%. We have recently received approval for our drilling permit from the State of Wyoming and we intend to commence the drilling of an initial exploration well during 2003.

Mallard Project. The Mallard project, located within the Overthrust Belt of SW Wyoming, is a sour gas and condensate exploration prospect in Uinta County, Wyoming. Mallard is within the Paleozoic trend of productive fields on the Absaroka thrust. Mallard directly offsets and is adjacent to the giant sour gas field of Whitney Canyon-Carter Creek.

We interpret the Mallard prospect to occupy a separate fault block, adjacent to the Whitney Canyon field, generated by a complex imbricated system of faults spaying off of the Absaroka thrust. Paleozoic targets at the Mallard prospect include the Mississippian Mission Canyon, as well as numerous secondary objectives in the Ordovician, Pennsylvanian, and Permian sections.

We currently control approximately 3,900 gross and net acres in the project and expect to sell down our working interest to between 25% and 50%. We intend to commence the drilling of an initial exploration well during 2003.

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.

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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.

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

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 and this production continued throughout fiscal 2002. At August 31, 2002, the Company had production from only the ELH #1 well. During the fiscal year ended August 31, 2002, the Company's net share of production from this well was 39,468 mcf of natural gas and 1,600 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, 2002, we continued our participation in three gross (0.283 net) development wells at East Lost Hills. We also participated in one gross (0.00 net) exploration well at the Pyramid Power prospect with a carried through the tanks working interest. The ELH #4 well reached a total depth of approximately 20,500 feet on November 17, 2001. The ELH #9 well reached a total depth of approximately 21,100 feet on April 10, 2002 and the Aera Energy LLC NWLH 1-22 well reached a total depth of 20,457 feet on August 16, 2002.

- 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. The ELH #9 well commenced drilling on July 18, 2001, and on August 23, 2001, the Aera Energy LLC NWLH 1-22 well commenced drilling.

- 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. The ELH #3 well was found to contain hydrocarbons in non-commercial amounts.

In addition, in October 2002 we participated in the drilling of an exploratory well in the DJ Basin of Colorado. This well, which was drilled to a depth of approximately 4,800 feet was found to contain non-commercial deliverability of hydrocarbons and was plugged and abandoned.

Although there is no assurance that any additional wells will be drilled, we anticipate we may commence drilling up to five exploration wells during fiscal 2003 on our exploration projects other than East Lost Hills. We do not expect to participate in the drilling of any additional wells at East Lost Hills during 2003. 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. Concurrent with the end of our fiscal year ended August 31, 2001, we engaged Netherland, Sewell & Associates, Inc., independent petroleum engineers, to prepare a reserve report for the reserves related to our ownership interest in the East Lost Hills project. 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. No additional meaningful production was established during fiscal 2002 and, accordingly, no reserve report was prepared as of the August 31, 2002 fiscal year end. Previous to August 31, 2001, all of our oil and gas properties were classified as undeveloped, and no reserve reports were warranted.

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, 2002. 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, 2002, our amortizable cost pool was comprised of East Lost Hills drilling and completion costs associated with our working interests in the ELH #4, ELH #9, and the Aera NWLH 1-22 wells and allocated land, geological and geophysical costs in the aggregate amount of approximately $11,669,000, and capital costs associated primarily with a Colorado DJ Basin project in the amount of approximately $54,000. 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	65,000	35,000
Montana	242,000	226,000
Wyoming	12,000	12,000

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TOTAL	319,000	273,000
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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 currently 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 $3 million on exploration and development activities during our fiscal year ending August 31, 2003. 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 exploration success and subsequent success in developing our exploration projects. Our future growth plans rely heavily on discovering reserves and initiating production in the San Joaquin Basin and in the Rocky Mountains. This lack of diverse business operations subjects us to a high degree of risk.

Our development plan includes the need to discover reserves and establish commercial production through exploratory drilling and development of our existing properties. We cannot be sure, though, that our planned projects will lead to significant reserves that can be economically extracted or that we will be able to drill productive wells at anticipated finding and development costs. If we are able to record reserves, our reserves will decline as they are depleted, except to the extent that we conduct successful exploration or development activities or acquire other properties containing proved reserves.

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

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 recorded a write-down of approximately $13,340,000 to reduce the carrying value of our oil and gas properties. No additional meaningful production was established during our fiscal year ended August 31, 2002, and we recorded an additional impairment of $11,723,000 against 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 may not be able to retain our listing on the American Stock Exchange. The American Stock Exchange has certain listing requirements in order for a company to continue to have their securities traded on this exchange. Although the American Stock Exchange does not identify a specific minimum price per share that a company's stock must trade above, a company may risk delisting if their common stock trades at a low price per share for a substantial period of time.

We have not been notified of any listing concerns by the American Stock Exchange. However, should our stock trade at a low share price for a substantial period of time, we may not be able to retain our listing.

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.

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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, 2002.

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, 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
Fiscal Year Ended August 31, 2002		
First Quarter....................	$2.830	$1.500
Second Quarter...................	2.700	1.800
Third Quarter....................	2.250	1.150
Fourth Quarter...................	2.350	0.700

On December 27, 2002, the last reported sales price of our common stock on the AMEX was 31 cents.

Stockholders Of Record

As of December 27, 2002, the number of record holders of our common stock was approximately 600 and the number of beneficial owners of our common stock was approximately 3,300.

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Dividends

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

Recent Sales Of Unregistered Securities; Use Of Proceeds From Registered Securities

On May 24, 2002, we received $6 million in gross proceeds from the sale of convertible notes due May 24, 2009. These notes call for semi-annual interest payments at an annual rate of 4.99% and are convertible into shares of common stock at a conversion price of $1.30 per share. The interest can be paid in cash or added to the principal amount at the discretion of the Company. The notes were issued to three investment funds pursuant to exemptions from registration under Section 3(b) and/or 4(2) of the Securities Act of 1933, as amended. Proceeds from the notes will be used for capital expenditures related to our oil and gas activities, for administrative costs and for other related costs.

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, 2002, approximately $11,288,000 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, 2002, the balance of the net proceeds continue to be held for those purposes.

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 August 31,			
	2002	2001	2000	19
Operating Revenues	$ 278,214	$ 1,624,096	$ 165,411	$ 1
Net (loss) from operations	(13,129,828)	(13,142,291)	(982,547)	(1,1
Net income (loss(per share)	(.55)	(.59)	(.07)	
Total assets at the end of each period .	13,400,250	22,067,184	19,942,090	10,7
Long-term debt at the end of each period	6,000,000	-0-	-0-	

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, 2002, we had approximately $6,030,854 in working capital.

During the fiscal year ended August 31, 2002, our capitalized costs for undeveloped oil and gas properties decreased by approximately $4,206,000. The decrease is the result of an impairment taken against our oil and gas properties in the amount of $11,723,000 and $250,000 in seismic sales credited to the full cost pool during the fiscal year ended August 31, 2002. The decrease was offset by approximately $7,767,000 of costs incurred for drilling and completion, geological and geophysical costs, delay rentals, and other related direct costs with respect to our exploration and development projects.

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.

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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 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 issued in conjunction with a private placement that was completed in May 1999 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 issued in the May 1999 private placement had been exercised to purchase a total of 164,063 shares of our common stock for total proceeds 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.

In May 2002, we received $6,000,000 in gross proceeds from the sale of convertible notes which resulted in long term debt of $6,000,000 at August 31, 2002. We had no outstanding long-term debt at August 31, 2001. 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, 2003 will depend on our success in selling additional prospects for cash, the level of industry participation in our exploration projects, the availability of debt or equity financing, and the results of our activities, including continuing results at our East Lost Hills project. We anticipate spending a minimum of approximately $3 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 2002, we incurred approximately $5,825,000 for costs relating to drilling and completing wells at our East Lost Hills Project. We incurred approximately $1,942,000 for costs related to our other exploration projects including continued acreage lease obligations and associated geological and geophysical costs. Revenues from oil and gas production during 2002 were $132,569.

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.

We currently anticipate that we will participate in the drilling of up to five exploration wells during our fiscal year ending August 31, 2003, 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, 2002 ("2002") compared with the twelve months ended August 31, 2001 ("2001")

Operations during the fiscal year ended August 31, 2002 resulted in a net loss of $13,129,828 compared with a net loss $13,142,291 for the fiscal year ended August 31, 2001.

Oil and Gas Revenues and Expenses. During the year ended August 31, 2002, we recorded $102,637 from the sale of 39,468 mcf of natural gas for an average price of $2.60 per mcf and $29,932 from the sale of 1,600 bbls of hydrocarbon liquids for an average price of $18.71 per barrel. Lease operating expenses during this period were $91,384. During the year ended August 31, 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. Lease operating expenses during this period were $102,018. Production commenced at the East Lost Hills ELH #1 well on February 6, 2001. Prior to this date, none of our oil or gas properties was producing.

Interest Income. We recorded $145,645 and $422,117 in interest income for the years ended August 31, 2002 and August 31, 2001, respectively. Interest income was higher in the prior fiscal year due 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 $1,496,329 and $1,306,635 in general and administrative expenses during 2002 and 2001, respectively. The increase results primarily from the value of warrants issued in conjunction with a financial advisory agreement.

Depreciation, Depletion and Amortization. We recorded no depreciation, depletion and amortization expense from oil and gas properties for the years ended August 31, 2002 or August 31, 2001. Although the ELH #1 began producing during 2001, we recorded an impairment against our entire amortizable full cost pool both at August 31, 2002 and August 31, 2001, and therefore had no costs to amortize. We recorded $14,605 and $17,823 in depreciation expense associated with capitalized office furniture and equipment during the years ended August 31, 2002 and August 31, 2001, respectively.

Dry Hole, Impairment and Abandonments. In 2002, we recorded an impairment expense of $11,722,830, primarily for the remaining basis in our East Lost Hills project. Additionally, approximately $54,000 of the current year impairment charge related primarily to a Colorado exploration project where an unsuccessful exploration well was drilled in October 2002. Although properties may be considered as evaluated for purposes of the ceiling test and included in the impairment calculation, until these properties are completely abandoned, we may continue to incur related costs. Until we can establish economic reserves, of which there is no assurance, additional costs associated with these properties are charged directly to impairment expense as incurred. In 2001, we recorded an impairment of $13,339,911 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 related primarily to our East Lost Hills project, and included costs for our Southeast Maricopa project and our interests in the Cal Canal and Lucky Dog prospects in the approximate amount of $2,812,000.

Interest Expense. We recorded $82,894 in interest expense for the year ended August 31, 2002 and no interest expense for the year ended August 31, 2001. The current year interest expense results from the May 24, 2002 sale of convertible notes, for which we received $6 million in gross proceeds. The notes are due May 24, 2009, and call for semi-annual interest payments at an annual rate of 4.99% and are convertible into common stock at a conversion price of $1.30 per share. The interest can be paid in cash or added to the principal amount at the discretion of the Company. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our August 31, 2002 balance sheet.

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 with 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.

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

The information required under Item 7A is not applicable.

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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	44	Chief Executive Officer, President, and Chairman Of the Board	1997
Andrew P. Calerich	38	Chief Financial Officer, Vice President and Secretary	---
S. L. Hutchison	70	Director	1999
David Kilpatrick	52	Director	2002
Borden Putnam	49	Director	2002
Bryce W. Rhodes	49	Director	1999
Eric M. Sippel	41	Director	2002
Kenneth R. Berry, Jr.	50	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.

David B. Kilpatrick has been a Director of the Company since June 2002. He is currently President of Kilpatrick Energy Group, which provides strategic management consulting services to the California oil and gas industry. Prior to the 1998 merger with Texaco, he was President and Chief Operating Officer of Monterey Resources, Inc., the largest independent oil and gas producer in California. Previously, he served as Western Division Manager of Monterey's corporate predecessor, Santa Fe Energy Resources, from 1990 to 1996. Mr. Kilpatrick has served as President of the California Independent Petroleum Association and is a member of its Board of Directors and also serves as a Director of the Independent Oil Producers Agency. In the past, he has served on the Board of Directors of the Western States Petroleum Association and the Conservation Committee of California Oil and Gas Producers. He earned a Bachelor of Science degree in Petroleum Engineering from the University of Southern California and a Bachelor's Degree in Geology and Physics from Whittier College.

Borden Putnam became a Director of the Company in May of 2002. Mr. Putnam has been an analyst with Eastbourne Capital Management, L.L.C. since July 2001. Prior to Eastbourne, Mr. Putnam was a principal and analyst at RS Investment Management from 1996 to 2001. From 1991 to 1996, Mr. Putnam was VP of Geology for an international mining consulting firm and from 1982 to 1991, he was a manager and district manager with Newmont Exploration. Mr. Putnam began his career as a geologist with AMAX Exploration in 1975. He is a Registered Professional Geologist, and holds B.S. and M.S. degrees in Geology and Geochemistry from the New Mexico Institute of Mining and Technology. Mr. Putnam is a member of the Society of Economic Geologists, AAPG, and SME.

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.

Eric M. Sippel became a Director of the Company in May of 2002. Mr. Sippel joined Eastbourne Capital Management, L.L.C. as its Chief Operating Officer and General Counsel in 2000. Prior to that, he was a partner at the law firm of Shartsis, Friese & Ginsburg LLP, in San Francisco, California, where he practiced law from 1990-1999. Mr. Sippel currently serves on the Board of Directors of Blacklight Power, Inc., a private company. He received his B.A. degree with Honors in General Scholarship from Wesleyan University in 1983 and his J.D. degree with Distinction from Stanford Law School in 1986.

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. 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, 2002, 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, 2002 on behalf of the Company's directors, officers and holders of more than 10% of the Company's common stock.

ITEM 11. EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth in summary form the compensation received during each of the last three completed fiscal years ended August 31, 2002 by D. Scott Singdahlsen, our Chief Executive Officer, President and Chairman Of The Board, and Andrew P. Calerich, our Chief Financial Officer, Vice President and Secretary. Other than Messrs. Singdahlsen and Calerich, none of our executive officers received total salary and bonus exceeding $100,000 during any of the last three fiscal years.

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Summary Compensation Table

Name and Principal Position	Fiscal Year	Annual Compensation: Salary ($)(1)	Annual Compensation: Bonus ($)(2)	Annual Compensation: Other Annual Compensation ($)(3)	Long-Term Compensation Awards: Restricted Stock Awards ($)	Long-Term Compensation Awards: Options (#)	Long-Term Compensation Payout: LTIP Payout ($)(4)
D. Scott Singdahlsen	2002	$175,000	$-0-	-0-	-0-	-0-	-0-
Chief Executive Officer,							
President and Chairman	2001	$128,250	$40,000	-0-	-0-	-0-	-0-
Of the Board							
	2000	$110,000	$-0-	-0-	-0-	-0-	-0-
Andrew P. Calerich	2002	$95,682	$-0-	-0-	-0-	-0-	-0-
Chief Financial Officer,							
Vice President and	2001	$90,666	$10,000	-0-	-0-	-0-	-0-
Secretary							
	2000	$85,000	$-0-	-0-	-0-	-0-	-0-

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

(2) The dollar value of bonus (cash and non-cash) received during the year indicated.

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

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

(5) All other compensation received that we could not properly report in any other column of the Summary Compensation Table including annual Company contributions or other allocations to vested and unvested defined contribution plans, and the dollar value of any insurance premiums paid by, or on behalf of, the Company with respect to term life insurance for the benefit of the named executive officer, and, the full dollar value of the remainder of the premiums paid by, or on behalf of, the Company.

Option Grants Table

The following table provides certain summary information concerning individual grants of stock options made during the fiscal year ended August 31, 2002 to the following named executive officers.

Option Grants For Fiscal Year Ended August 31, 2002

Name	Number of Securities Underlying Options Granted (#)	% of Total Options Granted to Employees in Fiscal Year	Exercise Price ($/Share)	Expiration Date
D. Scott Singdahlsen	15,000	5.8%	$1.82	4/11/07
Andrew P. Calerich	45,000	17.6%	$1.68	4/11/07

Aggregated Option Exercises And Fiscal Year-End Option Value Table

The following table provides certain summary information concerning stock option exercises during the fiscal year ended August 31, 2002 by the named executive officers and the value of unexercised stock options held by the named executive officers as of August 31, 2002.

Aggregated Option Exercises
For Fiscal Year Ended August 31, 2002
And Year-End Option Values (1)

			Number of Securities Underlying Unexercised Options at Fiscal Year-End (#) (4)		Value Mone Fiscal
Name	Shares Acquired on Exercise (2)	Value Realized ($)(3)	Exercisable	Unexercisable	Exercisab
D. Scott Singdahlsen	N				