KAUFFMAN ROBERT R
Form 4
August 15, 2006

FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

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(Print or Type Responses)

1. Name and Address of Reporting Person *
KAUFFMAN ROBERT R

(Last) (First) (Middle)

15575 N 83RD WAY, SUITE 3

(Street)

SCOTTSDALE, AZ 85260

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
ALANCO TECHNOLOGIES INC [ALAN]

3. Date of Earliest Transaction (Month/Day/Year)
08/15/2006

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

__X__ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
CEO

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

Persons who respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security	2. Conversion or Exercise	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any	4. Transaction Code	5. Number of Derivative Securities	6. Date Exercisable and Expiration Date (Month/Day/Year)	7. Title and Amoun Underlying Securiti (Instr. 3 and 4)

(Instr. 3)	Price of Derivative Security		(Month/Day/Year)	(Instr. 8)		Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)					
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amou Numb Share
Class A Common Stock Options	$ 0.55	08/15/2006		A		150,000		08/15/2006 (1)	08/15/2011	Class A Common Stock	150,

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
KAUFFMAN ROBERT R 15575 N 83RD WAY SUITE 3 SCOTTSDALE, AZ 85260	X		CEO	

Signatures

Robert R. Kauffman	08/15/2006
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Vesting - 10% - 8/15/06, 15% - 8/15/07, 25% - 8/15/08, 25% - 8/15/09, 25% - 8/15/10

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. 04 acquisition of interests in certain producing properties from Venus Exploration, Inc. ("Venus") resulted in the increase of oil and gas purchasers. We are not confined to, nor dependent upon, any one purchaser or small group of purchasers. Accordingly, the loss of a single purchaser would not materially affect the Company's business because we believe we would be able to find another purchaser. Employees and Office Space At August 31, 2004, we had eight full time employees. We believe that our relationship with our employees is satisfactory. None of our employees is 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. We have an additional office in San Antonio, Texas, in which we lease approximately 4,300 square feet. Business Strategy Our objective is to increase stockholder value per share by adding reserves, production, cash flow, earnings and net asset value. To accomplish this objective, we intend to 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: o our inventory of Texas, Rocky Mountain, and California exploration projects, o our control of pre-drill exploration phases, o our expertise in advanced seismic imaging, and o our ability to identify suitable development and exploitation drilling opportunities. To implement our strategy, we seek to: o Execute Exploration Drilling on Our Undrilled Projects. We control interests in several exploration projects in the Texas Gulf Coast, select areas of the Rocky Mountains, and the San Joaquin Basin of

California. In the Rocky Mountains, our most notable projects are Cumberland, Mallard, and Ryckman Creek located in southwestern Wyoming, and our Montana Foothills project. We have recently commenced drilling of our Mallard and Cumberland projects. After signing our exploration agreement with SENGAI for our Montana Foothills project, we expect SENGAI to commence drilling a well by year end. In the Texas Gulf Coast, we have interests in several exploration projects and PUD ("Proved Undeveloped") locations related to recent discoveries to be drilled in the future. 3 o 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. o Evaluate Low Risk, Shallow Exploitation and Development Drilling Opportunities. As part of our ongoing strategy, we are evaluating lower risk drilling opportunities relative to our higher risk, internally generated, exploration projects. If found to be appropriate, these opportunities can provide the Company with suitable internal rates of return on investment, geographic and risk diversification, and exposure to reserves and potential cash flow. To this end, while we have evaluated numerous opportunities, we have recently signed joint venture agreements that provide the Company with shallow gas re-completion opportunities in southeast Alberta, Canada. We continue to review and evaluate additional development and exploitation opportunities as they arise. o Continue A Disciplined Acquisition Process. As part of our ongoing strategy, we diligently look for properties or opportunities with significant upside in our core areas. Through our personal contacts, industry knowledge and expertise, we look to find under-worked properties or missed structures, that with little cost, but strong operatorship, may be productive. Significant Projects Our exploration activities are focused primarily in select areas of the Rocky Mountains, Texas and Gulf Coast, Southeast Alberta, and in the San Joaquin Basin of California. 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. Rocky Mountain Exploration Montana Foothills Project. This extensive natural gas exploration project, located in west-central 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 the 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, the Unocal #1-B30, drilled in 1989 to a depth of 17,817 feet, which was plugged and abandoned after testing. 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. Within the Rogers Pass acreage block, we have undertaken extensive seismic analysis and geological study, resulting in the identification of multiple untested, prospective structures. In March 2004, we signed an Exploration Option Agreement with a subsidiary of Suncor Energy, Incorporated, covering our Rogers Pass exploration project We currently control approximately 241,800 gross and 226,300 net leasehold acres in the Rogers Pass project. Pursuant to our agreement with the subsidiary of Suncor Energy, Suncor Energy Natural Gas America, Inc. ("SENGAI"), SENGAI has paid us a $500,000 option fee for a technical evaluation period of up to three months. On August 31, 2004 SENGAI exercised its option to drill an initial test well at Rogers Pass, and paid us $750,000 in the form of a prospect fee (received in 4 September 2004). It is anticipated that the initial test well will be spud prior to December 31, 2004. SENGAI will bear 100% of the costs of the well, to a depth sufficient to evaluate the Mississippian, to earn a 100% working interest in 100,000 acres of the project area. SENGAI will have the option to pay a second prospect fee of $1,250,000 and drill a second test well, to be spud by December 31, 2005. By paying this second prospect fee and bearing 100% of the costs of the second well, SENGAI will earn a 100% working interest in the remaining acreage within the project area. We will retain a 12.5% overriding royalty interest, subject to amortized recovery of gas plant and certain transportation costs, covering all earned acreage within the Rogers Pass project area. Mallard Project. The Mallard project, located within the Overthrust Belt of southwest Wyoming, is a sour gas and condensate exploration prospect in Uinta County, Wyoming. We believe that 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 splaying 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. The agreement we entered into with two private companies ("the Participants") in December 2003 requires the Participants to drill the initial test well at the Mallard Prospect to earn part of our acreage position within a designated area of mutual interest. We currently control 4,160 net leasehold acres within the AMI. The partners have paid us approximately $450,000 in prospect fees and pro-rata development costs. The Mallard well started drilling in mid-July. Intermediate casing was set to 9,735 feet in the Thaynes Formation. The Bureau of Land Management has suspended drilling activities at Mallard, effective December 1, 2004, due to wildlife critical winter range restrictions. As a result, the well will be temporarily suspended and secured in compliance with applicable federal and state regulations, until the wildlife restrictions are lifted in mid - 2005. We are participating with a 5% working interest in the drilling of Mallard, and will be carried to casing point, at an estimated total depth of 15,500 feet, for an additional 23.75% working interest. After casing point, we will have a 28.75% working interest in the initial test well and all subsequent wells in the prospect. 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. We believe that the prospect is along geologic 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. Drilling at the Cumberland prospect started in early November 2004, and the well is currently drilling ahead. The partners paid us $186,016 in prospect fees and pro-rata development costs. An additional $86,004 will be paid upon the well reaching casing point. We will participate with a 10% working interest in the drilling, and will be carried for an additional 22.5% working interest to casing point in the initial test well. After casing point, we will have a 32.5% working interest in the initial well and all subsequent wells in the Prospect. The anticipated total depth of the well is estimated to be 10,600 feet. We control 6,233 net leasehold acres within the Cumberland area of mutual interest. Ryckman Creek Project. We have recently leased approximately 1,820 net acres, covering the majority of the abandoned Ryckman Creek field, in the Overthrust of southwestern Wyoming. Ryckman Creek, located 5 miles southwest of our Cumberland prospect, was discovered in 1975 and produced approximately 250 Bcfe prior to abandonment. We believe that significant remaining recoverable gas reserves were stranded in Ryckman Creek upon abandonment. We are currently analyzing production and geologic data to determine potential reserves in multiple zones, including the Twin Creek, Nugget, and Thaynes Formations, in the field. Due to winter activity restrictions, it is anticipated that a well may be drilled at Ryckman Creek in mid-2005, and based on our analysis, we may decide to sell part of our 100% working interest in the project. 5 Interests Acquired from Venus Exploration, Inc.: In May 2004, we acquired interests from Venus Exploration, Inc. ("Venus") in certain producing properties with estimated proved reserves of 4.784 Bcfe for approximately $3,230,000 (excluding acquisition expenses and subject to retention, by the Venus Exploration Trust, of a net profits interest covering the non-productive exploration projects). This equates to $0.67 per Mcf, with a PV-10 value of $6.94 million. The purchase also provides for us to pay a net profits interest payable to the Venus Exploration Trust. The net profits interest, which applies only to the exploration and exploitation projects on the Venus acreage being acquired, varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust. Venus was in Chapter 11 Bankruptcy, and the properties were acquired through public auction as approved by the United States Bankruptcy Court. To finance the purchase, we primarily used existing cash reserves and also a portion of the proceeds from a private placement of common stock. Oil and gas interests acquired from Venus include producing oil and gas properties, exploitation drilling projects, and exploration acreage. The assets acquired include interests in 80 non-operated wells in Utah, Oklahoma and Texas. As of August 31, 2004, net production from the acquired properties was approximately 1.42 MMcfe per day. Workovers of these existing properties conducted since the acquisition date have increased daily production by 392 Mcfe, or approximately 42% during the fourth quarter ended August 31, 2004. In Texas, we have interests in three projects that were drilled and completed over this past summer. Two of the three wells, the Nome and Madison Prospects, were completed as producers and are currently flowing to sales lines. These two successful projects are, upon reaching payout, subject to a 50% net profits interest payable to the Venus Exploration Trust. Tortuga Grande prospect, located in east Texas, is a re-entry of an existing well, drilled on a large turtle structure, to test the productivity of the Cotton Valley Sand section at depths ranging from 13,000 to 14,500 feet. Drilled originally in 1984 for deeper targets, the Brady #1 is the only deep well on the structure, and had shows in the Cotton Valley Sand, but was never fracture stimulated. Log analysis of the re-entry indicates that the well contains approximately 322 feet of potential pay greater than 8% porosity. The middle Cotton Valley Sand section was fracture stimulated and tested. Results of the test were inconclusive and the partners continue to evaluate the test data. The partners may decide at a future date to drill another well to test the Cotton Valley within the project area. Should this occur, PYR would be responsible for 20% of the costs of any additional well. In all additional locations within the Tortuga Grande area of mutual interest, we will participate with a cost bearing 20% working interest. We currently control approximately 5,600 net leasehold acres within the project. Nome Field was discovered in 1994, and our interpretation of subsequently acquired 3D seismic over the field indicates the presence of numerous undeveloped fault blocks. Multiple structural closures and associated bright spot locations have been identified at Nome based on the 3D seismic. PYR owns a 1.5% overriding royalty interest with an additional 8.33% working interest, after project payout, in the project. Production in the Sun Fee #1 well, from the upper Yegua, was initiated in late May 2004, and current well production has stabilized at rates in excess of 11 MMcf/d with approximately 700 Bc/d. It is estimated that the well has produced in excess of 1.5 Bcfe since inception. After project payout, it is estimated that the well will add approximately 1MMcfe of net daily production to PYR, given current production rates. Although we have yet to receive confirmation from the operator, we believe, based on production levels and product prices, that the well and project have reached payout, and that PYR is currently a working interest participant in the well. We and our partners control approximately 4,200 acres of gross leasehold acres in the project. We are currently in dispute with the operator of the Sun Fee #1, Sampson Lone Star L.P., concerning the pooling of certain lands into the production unit. The pooling of these lands in which the Company does not own an interest, comprises approximately 32% of the unit area, and may result in a reduction of working interest and net revenue interest, relative to production from the Sun Fee #1, attributable to the Company. If the current pooling were to stand, our working interest in the well would be reduced from 8.33% to 5.66%. The Company strongly believes that the lands in question are 'Non-Productive', and therefore not eligible for pooling, based on all available geological, seismic, and existing well data. As a result of this dispute, we will vigorously pursue and defend our rights to our proportionate share of production and revenue from the Sun Fee #1 with all legal avenues and remedies available. For this reason, the Company has not signed any of the proposed production and revenue division orders, and has not received any revenue, attributable to the well, to date. If 6 we undertake legal action against the operator relative to this issue, which we currently intend, it may result in all revenues attributable to the Sun Fee #1 well being held in suspense until the legal action is completed. As of August 31, 2004, we accrued $68,478 in royalty interest revenues from the Sun Fee #1, which began producing in late May 2004. The amount accrued reflects the royalty interest percentage stated in the division order we received from the operator. Madison prospect, located in the northern part of the Constitution Field, is an exploitation project to test multiple sand intervals within the expanded Yegua section, downthrown to a major growth fault. The prospect involves sidetracking an existing cased hole updip to test multiple sand targets at a location offsetting, but significantly high to Doyle sand production from the Texaco #1 Doyle well within the field. The location is also offset to the Texaco #1 Sanders Gas Unit well, which tested the Doyle sand interval at a rate of 1,176 Bc/d and 2.7 MMcf/d with no water. This well was subsequently plugged and abandoned in the Doyle interval and never produced from the zone. The Sanders Gas Unit location represents a proved undeveloped location for Doyle sand, 183 feet structurally high to the equivalent produced zone in the Texaco Doyle #1 well. The current well has been drilled to total depth, production casing has been run, and the well is currently producing at restricted rates of approximately 2.1 MMcf/d with 450 Bc/d. We own a 0.5% overriding royalty interest that converts to a 12.5% working interest in the project after payout of the initial test well. The operator has converted an existing wellbore within the project area into a water disposal well, and is planning to drill an offset development well within the next few months. The cost of the water disposal well will be covered under the payout account, and we will participate for 12.5% working interest in the drilling of the development well. The Cotton Creek prospect, located in Jefferson County, Texas, is adjacent to the Nome project. The prospect is located approximately one mile west of the productive Sun Fee #1 well in the same structural fault block. PYR owns a 50% working interest in the project and controls with its partner approximately 500 acres of leasehold. The South Wharton prospect, located in Wharton County, Texas, is an exploration project designed to test several stratigraphic intervals within the expanded Yegua section in multiple structural features as defined by 3D seismic data. Drilling targets are estimated to be at depths between 11,000 and 13,500 feet. PYR owns a 58% working interest in the project and in excess of 1,065 gross acres are currently under lease. The Merganser prospect, located in Leon County, Texas, targets Cotton Valley and Bossier sandstone reservoirs in an undrilled structural feature defined by 3D seismic data. The prospect occupies a fault-bounded salt-withdrawal trough resulting in potential significant thickening of the Bossier and Cotton Valley sand sections. The prospect location is structurally and stratigraphically downdip from Cotton Valley production as well as updip from recent Bossier productive discoveries. PYR owns 100% of the prospect and controls in excess of 1,500 gross acres of leasehold. Southeast Alberta Shallow Gas Redevelopment Project: We have entered into two joint ventures, the Atlas Joint Venture and the Blue River Joint Venture, to redevelop shallow gas reserves in southeastern Alberta, Canada. Southeastern Alberta has been the site of significant shallow gas development drilling and production over the last two decades. We have undertaken geologic and engineering studies of the region, and believe that many wellbores in the region were prematurely suspended and/or abandoned due to water coning and production. These premature well abandonments suggest the possibility that significant additional reserves may remain in a number of shallow gas reservoirs in local areas within the Southeastern Alberta. We own a 5% working interest in the Atlas Joint Venture, which has identified multiple potential re-entry and redevelopment opportunities for which the Joint Venture intends to acquire the right to participate. The first well has been re-entered, re-perforated, and completed in the upper Bow Island sand. The well is currently producing into a sales line during long term testing. An offset wellbore is currently being permitted for re-entry based on results from the initial well. A number of other prospects are being leased and permitted at this time. We also own a 25% working interest in the Blue River Joint Venture, which intends to operate in different areas of southeastern Alberta. Initial investigation indicates multiple wells that exhibit an appropriate production type decline curve, potential disposal interval, and gas reservoir. We are currently undertaking detailed geologic and production analysis to refine certain areas, for which the Joint Venture will undertake to acquire and develop prospects for recompletion or drilling. 7 San Joaquin Basin, California 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. Despite repeated attempts to facilitate drilling interest at Wedge during 2003, no industry interest was generated sufficient to put together a drilling partnership during the year. As a result, PYR re-evaluated its acreage position at Wedge and made the decision to consolidate the leasehold by abandoning non-core prospect acreage in the project area. We currently control approximately 3,500 gross and net acres here. Our approach is to sell down our working interest to industry partners, 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. During 2003, we re-evaluated our acreage position at Bulldog and consolidated the leasehold by releasing approximately 3,200 non-core acres in the project area. We currently control approximately 11,900 gross and 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. Blizzard Prospect. This project is a 3D seismic derived exploration and exploitation program offsetting the Rio Viejo field at the south end of the San Joaquin Basin. A linear sand body, stratigraphically higher than any of the productive Rio Viejo sands, has been identified, north of the field, on the seismic data and represents an exploration opportunity for new reserves. Additionally, analysis of the seismic data over the field suggests that up to two additional undrilled field exploitation locations may exist. PYR owns 100% of the prospect and controls approximately 2,500 net and gross acres. Certain Definitions Unless otherwise indicated in this document, oil equivalents are determined using the ratio of six Mcf of natural gas to one barrel of crude oil, condensate or natural gas liquids so that six Mcf of natural gas are referred to as one barrel of oil equivalent. AMI. Area of Mutual Interest Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons. Bbl/d. One Bbl per day Bc/d. Barrels of condensate daily Bcf. One Billion cubic feet of natural gas at standard atmospheric conditions. Bcfe. One billion cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil. Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit. Capital Expenditures. Costs associated with exploratory and development drilling (including exploratory dry holes); leasehold acquisitions; seismic data acquisitions; geological, geophysical and land related overhead expenditures; delay rentals; producing property acquisitions; other miscellaneous capital expenditures; compression equipment and pipeline costs. 8 Carried through the tanks. The owner of this type of interest in the drilling of a well incurs no liability for costs associated with the well until the well is drilled, completed and connected to commercial production/processing facilities. Completion. The installation of permanent equipment for the production of oil or natural gas. Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve. Developed Acreage. The number of acres that are allocated or assignable to producing wells or wells capable of production. Development Well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive. Exploitation. The continuing development of a known producing formation in a previously discovered field. To make complete or maximize the ultimate recovery of oil or natural gas from the field by work including development wells, secondary recovery equipment or other suitable processes and technology. Exploration. The search for natural accumulations of oil and natural gas by any geological, geophysical or other suitable means. Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir. Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. Finding and Development Costs. The total capital expenditures, including acquisition costs, and exploration and abandonment costs, for oil and gas activities divided by the amount of proved reserves added in the specified period. Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest. Lease. An instrument which grants to another (the lessee) the exclusive right to enter to explore for, drill for, produce, store and remove oil and natural gas on the mineral interest, in consideration for which the lessor is entitled to certain rents and royalties payable under the terms of the lease. Typically, the duration of the lessee's authorization is for a stated term of years and "for so long thereafter" as minerals are producing. Mcf. One thousand cubic feet of natural gas at standard atmospheric conditions. Mcf/d. One Mcf per day. Mcfe. One thousand cubic feet equivalent of natural gas, calculated by converting oil to equivalent Mcf at a ratio of 6 Mcf to 1 Bbl of oil. MMcf. One million cubic feet of natural gas. Net Acres or Net Wells. A net acre or well is deemed to exist when the sum of our fractional ownership working interests in gross acres or wells, as the case may be, equals one. The number of net acres or wells is the sum of the fractional working interests owned in gross acres or wells, as the case may be, expressed as whole numbers and fractions thereof. Operator. The individual or company responsible to the working interest owners for the exploration, development and production of an oil or natural gas well or lease. 9 Participant Group. The individuals and/or companies that, together, comprise the ownership of 100% of the working interest in a specific well or project. PV-10 value. The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization or federal income taxes and discounted using an annual discount rate of 10%. Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes. Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons. Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions. Proved undeveloped reserves (PUD). Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Re-entry. Entering an existing well bore to redrill or repair. Reserves. Natural gas and crude oil, condensate and natural gas liquids on a net revenue interest basis, found to be commercially recoverable. Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/ or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs. Royalty. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage, or of the proceeds of the sale thereof, but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner. Sidetrack. An operation involving the use of a portion of an existing well to drill a second hole at some desired angle into previously undrilled areas. From this directional start, a new hole is drilled to the desired formation depth and casing is set in the new hole and tied back to the casing from the existing well. 3-D Seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, exploitation and production. Undeveloped Acreage. Lease acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether or not such acreage contains proved reserves. 10 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 Acquisition of the Venus assets in May 2004 resulted in the addition of production and reserves to the Company. The following table summarizes the Company's productive wells as of August 31, 2004. Productive wells are producing wells and wells capable of production. Gross wells are the total number of wells in which the Company has an interest. Net wells are the sum of the Company's respective fractional interests owned in the gross wells. Productive Gas wells as of August 31, 2004 Gross Net ----- --- Location Oil Gas Total Oil Gas Total Canada - 1 1 - 0.05 0.05 California 3 - 3 0.24 - 0.24 Oklahoma 6 18 24 2.21 0.40 2.60 Texas 39 11 50 14.34 2.96 17.30 Utah 5 - 5 1.59 - 1.59 -- TOTAL 53 30 83 18.38 3.41 21.78 Drilling Activities During the past two fiscal years, we participated in the drilling of the following exploration and development wells: o During the fiscal year ended August 31 2004, we participated in the drilling of two exploration wells in the expanded Yegua trend of South Texas (carried), one exploration well in the Cotton Valley section of East Texas, one exploration well in the Wyoming Overthrust (5% WI with carry), and one exploration well in SE Alberta. As of November 2004, the two exploration wells in South Texas have been classified as discoveries and are producing into sales lines. The well in Wyoming (Mallard Prospect) was drilling until the BLM suspended operations on December 1, 2004, and the well in Southeast Alberta was tested and determined to be non-productive. Additionally in fiscal year 2004, the Company participated in several well workovers in Texas, Oklahoma, and Utah. o During the fiscal year ended August 31, 2003, 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 drill additional exploration and development wells during fiscal 2005 on our projects in the Texas Gulf Coast and Rocky Mountains. The actual number of wells drilled will be dependent on several factors, including the results of our ongoing exploration efforts and the availability of capital. 11 Reserves August 31, 2004 estimates of `Total Proved' reserves were 5.502 Bcfe, which represents a 15% increase versus May 31, 2004 estimates of 4.784 Bcfe. Increased estimates for `total proved' reserves result from revisions on multiple properties including new PDP and PUD additions related to exploration drilling in the expanded Yegua trend of south Texas. For the year ended August 31, 2004, proved developed producing reserves are estimated at 2.627 Bcfe, while proved developed non-producing reserves are estimated at 1.575 Bcfe. Proved undeveloped reserves are estimated at 1.302 Bcfe. At August 31, 2004, present value, discounted at 10% ("PV-10") is $11,043,501 for total proved reserves, and $5,333,374 for proved developed producing reserves, as compared with PV-10 at May 31, 2004 of $6,941,526 for total proved reserves and $3,088,755 for proved developed producing reserves. This increase in present value is a reflection of higher prices at fiscal year end plus reserve additions and revisions. At August 31, 2003, the Company had no `Proved' reserves on its books. 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 The Company utilizes the full cost accounting method of accounting for oil and gas activities and has separate cost centers for the United States and Canada. As required for oil and gas companies that utilize the full cost method of accounting, we capitalize all costs associated with acquisition, exploration and development activities by cost center. In the United States, 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. The Company's full cost center in Canada currently contains only non-producing acreage (used for exploration and development activities). The cost of these leases is included in unevaluated costs and is recorded at the lower of cost or fair market value. If the capitalized cost of these properties is less than the fair market value, an impairment is recognized. For the year ending August 31, 2004, no property impairment charge was recorded. Acreage We currently control through lease, farmout, and option, the following approximate acreage position as detailed below: 12 Developed And Undeveloped Acreage As of August 31, 2004 Gross Acres Net Acres State Developed Undeveloped Developed Undeveloped -- California 1,044 20,115 111 -- Canada 640 5,000 32 250 Louisiana -- 2,547 -- 2,317 Montana -- 241,800 -- 226,300 Oklahoma 5,659 -- 197 -- Texas 25,633 11,302 9,610 7,853 Utah 4,943 -- 1,504 -- Wyoming -- 10,553 -- 10,553 -- TOTAL 87,919 291,317 11,454 247,273 == 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. 13 The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993, and resulted in a series of Orders being issued by FERC requiring interstate pipelines to provide transportation services separately, or "unbundled," from the pipelines' sales of gas and to provide open access transportation on a nondiscriminatory basis that is equal for all natural gas shippers. We do not believe that we will be affected by these or any other FERC rules or orders materially differently than other natural gas producers and marketers with which we compete. The FERC also has issued numerous orders confirming the sale and abandonment of natural gas gathering facilities previously owned by interstate pipelines and acknowledging that if the FERC does not have jurisdiction over services provided on those facilities, then those facilities and services may be subject to regulation by state authorities in accordance with state law. A number of states have either enacted new laws or are considering the adequacy of existing laws affecting gathering rates and/or services. Other state regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements, but does not generally entail rate regulation. Thus, natural gas gathering may receive greater regulatory scrutiny of state agencies in the future. Our anticipated gathering operations could be adversely affected should they be subject in the future to increased state regulation of rates or services, although we do not believe that we would be affected by such regulation any differently than other natural gas producers or gatherers. In addition, the FERC's approval of transfers of previously-regulated gathering systems to independent or pipeline affiliated gathering companies that are not subject to FERC regulation may affect competition for gathering or natural gas marketing services in areas served by those systems and thus may affect both the costs and the nature of gathering services that will be available to interested producers or shippers in the future. We conduct certain operations on federal oil and gas leases, which are administered by the Minerals Management Service, or MMS. Federal leases contain relatively standard terms and require compliance with detailed MMS regulations and orders, which are subject to change. Among other restrictions, the MMS has regulations restricting the flaring or venting of natural gas, and has proposed to amend those regulations to prohibit the flaring of liquid hydrocarbons and oil without prior authorization. Under certain circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially and adversely affect our financial condition, cash flows and operations. The MMS issued a final rule that amended its regulations governing the valuation of crude oil produced from federal leases. This rule, which became effective June 1, 2000, provides that the MMS will collect royalties based on the market value of oil produced from federal leases, and was further modified by amendments to the June 2000 MMS rules, effective July 1, 2004. Also, there is currently pending new proposed MMS Federal Gas Valuation rules concerning calculation of transportation costs, including the allowed rate of return in the calculation of actual transportation costs in non-arm's length arrangements. We cannot predict whether this new gas rule will become effective, nor can we predict whether the MMS will take further action on oil and gas valuation matters. However, we do not believe that any such rules will affect us any differently than other producers and marketers of crude oil with which we will compete. Additional proposals and proceedings that might affect the oil and gas industry are pending before Congress, the FERC, the MMS, state commissions and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. There is no assurance that the regulatory approach currently pursued by various agencies will continue indefinitely. Notwithstanding the foregoing, we do not anticipate that compliance with existing federal, state and local laws, rules and regulations will have a material or significantly adverse effect upon our capital expenditures, earnings or competitive position. No material portion of our business is subject to re-negotiation of profits or termination of contracts or subcontracts at the election of the federal government. 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. 14 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. 15 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 nine 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. Our cash resources are not unlimited. We need to increase our sources of revenue and/or funding in order to sustain operations for the long run. There is no assurance that this will occur. 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: 16 o unexpected drilling conditions, o pressure or irregularities in formations, o equipment failures or accidents, o adverse weather conditions, o compliance with governmental requirements, o shortages or delays in the availability of drilling rigs and the delivery of equipment, and o 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 $2,000,000 on exploration and development activities during our fiscal year ending August 31, 2005. Also, we must secure substantial capital to explore and develop our other potential projects. Historically, we have funded our capital expenditures through the issuance of equity. Volatility in the price of our common stock, which may be significantly influenced by our drilling and production activity, may impede our ability to raise money quickly, if at all, through the issuance of equity at acceptable prices. Future cash flows and the availability of financing will be subject to a number of variables, such as: o our success in locating and producing reserves in other projects, o the level of production from existing wells, and o 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: o a substantial portion of our operating cash flow being dedicated to the payment of principal and interest, o our being more vulnerable to competitive pressures and economic downturns, and o 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. 17 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, Texas, Gulf Coast and in the Rocky Mountains. Our development plan includes the need to discover reserves and establish commercial production through exploratory drilling and development of our existing properties. We cannot be sure, though, that our planned projects will lead to significant reserves that can be economically extracted or that we will be able to drill productive wells at anticipated finding and development costs. If we are able to record reserves, our reserves will decline as they are depleted, except to the extent that we conduct successful exploration or development activities or acquire other properties containing proved reserves. We depend on industry alliances. We attempt to limit financial exposure on a project-by-project basis by forming industry alliances where our technical expertise can be complemented with the financial resources and operating expertise of more established companies. While entering into these alliances limits our financial exposure, it also limits our potential revenue from successful projects. Industry alliances also have the potential to expose us to uncertainty if our industry partners are acquired or have priorities in areas other than our projects. Despite these risks, we believe that if we are not able to form industry alliances, our ability to fully implement our business plan could be limited, which could have a material adverse effect on our business. 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: o the availability of leases with favorable terms and the availability of required permitting for projects, o the availability of future capital resources to us and the other participants to be used for purchasing leases and drilling wells, o the approval of other participants for the purchasing of leases and the drilling of wells on the projects, and o 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: o have a material adverse effect on our results of operations, o limit our ability to attract capital, o make the formations we are targeting significantly less economically attractive, o reduce our cash flow and borrowing capacity, and o reduce the value and the amount of any future reserves. Various factors beyond our control will affect prices of oil and gas, including: o worldwide and domestic supplies of oil and gas, o the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls, o political instability or armed conflict in oil or gas producing regions, o the price and level of foreign imports, o worldwide economic conditions, o marketability of production, o the level of consumer demand, o the price, availability and acceptance of alternative fuels, o the availability of processing and pipeline capacity, o weather conditions, and o actions of federal, state, local and foreign authorities. 18 These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and gas. In addition, sales of oil and gas are seasonal in nature, leading to substantial differences in cash flow at various times throughout the year. Accounting rules may require write-downs. Under full cost accounting rules, capitalized costs of proved oil and gas properties may not exceed the present value of estimated future net revenues from proved reserves, discounted at 10%. Application of the ceiling test generally requires pricing future revenue at the unescalated prices in effect as of the end of each fiscal quarter and requires a write-down for accounting purposes if the ceiling is exceeded. If a write-down is required, it would result in a charge to earnings, but would not impact cash flow from operating activities. Once incurred, a write-down of oil and gas properties is not reversible at a later date. We face risks related to title to the leases we enter into that may result in additional costs and affect our operating results. It is customary in the oil and gas industry to acquire a leasehold interest in a property based upon a preliminary title investigation. In many instances, our partners have acquired rights to the prospective acreage and we have a contractual right to have our interests in that acreage assigned to us. In some cases, we are in the process of having those interests so assigned. If the title to the leases acquired is defective, or title to the leases one of our partners acquires for our benefit is defective, we could lose the money already spent on acquisition and development, or incur substantial costs to cure the title defect, including any necessary litigation. If a title defect cannot be cured or if one of our partners does not assign to us our interest in a lease acquired for our benefit, we will not have the right to participate in the development of or production from the leased properties. In addition, it is possible that the terms of our oil and gas leases may be interpreted differently depending on the state in which the property is located. For instance, royalty calculations can be substantially different from state to state, depending on each state's interpretation of lease language concerning the costs of production. We cannot guarantee that there will be no litigation concerning the proper interpretation of the terms of our leases. Adverse decisions in any litigation of this kind could result in material costs or the loss of one or more leases. Limitations on the Effectiveness of Controls. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls will prevent all possible error or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. These inherent limitations include the realities that judgments in decision making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Our industry is highly competitive and many of our competitors have more resources than we do. We compete in oil and gas exploration with a number of other companies. Many of these competitors have financial and technological resources vastly exceeding those available to us. We cannot be sure that we will be successful in acquiring and developing profitable properties in the face of this competition. In addition, from time to time, there may be competition for, and shortage of, exploration, drilling and production equipment. These shortages could lead to an increase in costs and delays in operations that could have a material adverse effect on our business and our ability to develop our properties. Problems of this nature also could prevent us from producing any oil and gas we discover at the rate we desire to do so. Technological changes could put us at a competitive disadvantage. The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As new technologies develop, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at a substantial cost. If other oil and gas exploration and development companies implement new technologies before we do, those companies may be able to provide enhanced capabilities and superior quality compared with what we are able to provide. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If we are unable to utilize the most advanced commercially available technologies, our business could be materially and adversely affected. 19 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. Should our stock trade at a low share price for a substantial

period of time, or our net tangible equity be below certain levels, we may not be able to retain our listing. We depend on key personnel. We 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: o failure to obtain, or a decline in, oil or gas production, or a decline in oil or gas prices, o incorrect estimates of required capital expenditures, o increases in the cost of drilling, completion and gas collection or other costs of production and operations, 20 o an inability to meet growth projections, and o other risk factors set forth under "Risk Factors" in this annual report. In addition, the words "believe," "may," "could," "will," "when," "estimate," "continue," "anticipate," "intend," "expect" and similar expressions, as they relate to PYR, our business or our management, are intended to identify forward-looking statements. ITEM 3. LEGAL PROCEEDINGS The Company is not a party to any, 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 The following matters were submitted to a vote of security holders at the annual meeting of stockholders which was held on June 11, 2004: The stockholders voted to re-elect D. Scott Singdahlsen, S.L. Huchison, David Kilpatrick and Bryce W. Rhodes to continue as directors of the Company. A total of 22,018,007 votes were represented with respect to this matter, with voting on each specific nominee as follows: BROKER FOR AGAINST WITHHELD NON-VOTES --- ------- -------- --------- D. Scott Singdahlsen 21,819,589 0 119,148 - S.L. Huchison 21,745,789 0 122,148 - David Kilpatrick 21,822,059 0 195,948 - Bryce W. Rhodes 21,822,589 0 119,678 - A proposal to approve the private placement of 3,000,000 shares of restricted common stock at a price of $1.09 per share was approved by the stockholders. A total of 11,747,005 votes were represented with a total of 11,456,714 (97%) shares voting for the proposal , 196,836 shares voting against the proposal, and 93,455 shares abstaining from voting. A proposal to approve the increase in the number of shares issuable pursuant to options granted under the 2000 Stock Option Plan from 1,500,000 shares to 2,250,000 shares was approved by the stockholders. A total of 11,747,005 votes were represented with a total of 10,407,525 (88%) shares voting for the proposal, 1,234,026 shares voting against the proposal, and 105,454 shares abstaining from voting. A proposal to ratify the selection of Hein+Associates LLP as our Certified Public Accountants was approved by the stockholders. A total of 21,941,737 votes were represented with a total of 21,734,058 (99%) shares voting for the proposal, 171,472 shares voting against the proposal, and 36,207 shares abstaining from voting. PART II ITEM 5. MARKET FOR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS Market For Common Equity Our common stock has been listed on the American Stock Exchange under the market symbol "PYR" since December 8, 1999. The following table sets forth the range of high and low sales prices per share of our common stock for the periods indicated. 21 High Low ---- --- Fiscal Year Ended August 31, 2003 First Quarter................. $1.00 $0.43 Second Quarter................ 0.42 0.22 Third Quarter................. 0.68 0.25 Fourth Quarter................ 0.82 0.36 Fiscal Year Ended August 31, 2004 First Quarter................. $0.83 $0.45 Second Quarter................ 1.81 0.53 Third Quarter................. 1.70 1.04 Fourth Quarter................ 1.32 0.75 On November 17, 2004, the last reported sales price of our common stock on the American Stock Exchange was $0.96 per share. Stockholders Of Record As of November 17, 2004, the number of record holders of our common stock was approximately 536. 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 None. Equity Compensation Plan Information Equity Compensation Plan Information
-- Number of Securities Remaining Available for Future Issuance under Number of Securities to be Equity Compensation Issued Upon Exercise of Weighted-Average Exercise Plans (Excluding Outstanding Options, Price of Outstanding Options, Securities Reflected in Plan Category Warrants and Rights Warrants and Rights Column (a))* -------------

------------------ ------------------ ------------ (a) (b) (c) Equity compensation plans approved by security holders 2,858,834 $1.64 731,000 Equity compensation plans not approved by security holders -0- -- -0- Total 2,858,834 731,000 ------------------------ * At August 31, 2004 22 ITEM 6. MANAGEMENT'S DISCUSSION AND ANALYSIS OR PLAN OF OPERATIONS The following discussion should be read in conjunction with the Consolidated Financial Statements and Notes thereto referred to in "Item 8. Financial Statements and Supplemental Data," and "Items 1. and 2. Business and Properties - Disclosures Regarding Forward-Looking Statements" of this Form 10-KSB. Overview We are an independent oil and gas exploration and production company engaged in the exploration, development and acquisition of crude oil and natural gas reserves. Our 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 additional exploratory drilling operations without outside industry participation. We have pursued, and will continue to pursue, exploration opportunities in regions where we believe significant opportunity for discovery of oil and gas 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. Two major financial developments that occurred during the fiscal year included the acquisition of interests from Venus Exploration, Inc. ("Venus") in certain producing properties with estimated proved reserves of 4.784 Bcfe for approximately $3,230,000 (excluding acquisition expenses and subject to retention, by the Venus Exploration Trust, of a net profits interest covering the non-productive exploration projects), and the private placement of our common stock, which raised $8,175,000 in gross proceeds. Liquidity and Capital Resources Our primary sources of liquidity historically have been from placements of common stock and convertible notes, and to a much lesser extent, cash provided by operating activities. Our primary use of capital has been for the acquisition, development, and exploration of oil and natural gas properties. As we pursue growth, we continually monitor the capital resources available to us to meet our future financial obligations, planned capital expenditure activities and liquidity. Our future success in growing proved reserves and production is highly dependent on capital resources available to us and our success in finding or acquiring additional reserves. At August 31, 2004, we had approximately $6,061,967 in working capital. During the fiscal year ended August 31, 2004, our capitalized costs for oil and gas properties increased by approximately $3,564,000. The increase is principally due to the acquisition of assets from Venus Exploration Inc. ("Venus"), and also includes net costs for drilling and completion, geological and geophysical costs, delay rentals, and other related direct costs with respect to our exploration and development projects, as well as an increase of $211,876 in asset retirement obligations related to the properties acquired from Venus, less depreciation of asset retirement obligation assets of approximately $113,462. No impairment was charged against our capitalized oil and gas properties within the United States cost center for the year ended August 31, 2004, as determined by the ceiling test performed pursuant to Regulation S-X Rule 4-10(c)(2). Additionally, there was no charge to impairment for the year ended August 31, 2004, against our unevaluated capitalized costs in Canada, which are recorded at the lower of cost or fair market value. During the year ended August 31, 2003, our capitalized costs for oil and gas properties decreased by approximately $1,484,000. The decrease is the result of an impairment taken against our oil and gas properties in the amount of $3,234,000 during the year, net of approximately $1,474,000 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, and net asset retirement obligation assets of approximately $276,000. 23 In early May 2004, we received subscriptions for an aggregate of $8,175,000 in gross proceeds from a private placement of our common stock. The private placement (the "Placement") consisted of the sale of 7.5 million shares of common stock, priced at $1.09 per share, to a group of twelve institutional and accredited individual investors pursuant to exemptions from registration under Sections 3(b) and 4(2) of the Securities Act of 1933, as amended. The first tranche of the

Placement, consisting of 4.5 million shares and $4,905,000 in gross proceeds, was received and accepted in early May 2004. The second tranche of the Placement, consisting of 3.0 million shares and $3,270,000 in gross proceeds, was approved by our stockholders at our Annual Meeting of Stockholders on June 11, 2004. We received the funds from the second tranche in late June 2004. Proceeds from the Placement will be used for general corporate purposes, partial funding of the acquisition of assets from Venus Exploration, Inc., and project development and drilling costs associated with our exploration and exploitation portfolio. The resale of these shares acquired in the Placement has subsequently been registered through a Registration Statement that has become effective with the SEC. In May 2004, we acquired interests in certain producing properties for approximately $3,230,000 (excluding acquisition expenses and subject to retention, by the Venus Exploration Trust, of a net profits interest covering the non-productive exploration projects) from Venus. Venus was in Chapter 11 Bankruptcy, and the properties were acquired through public auction as approved by the United States Bankruptcy Court. To finance the purchase, we primarily used existing cash reserves and also a portion of the proceeds from the Placement. The purchase also provides for a net profits interest payable to the Venus Exploration Trust. The net profits interest, which applies only to the exploration and exploitation projects on the Venus acreage being acquired, varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust. As of November 17, 2004, zero proceeds have been paid into the Trust. It is anticipated that the continuation and future development of our business will require additional, and possibly substantial, capital expenditures. We have no reliable source for additional funds for administration and operations to the extent our existing funds have been utilized. In addition, our capital expenditure budget for the fiscal year ending August 31, 2005 will depend on our success in selling additional prospects for cash, the level of industry participation in our exploration projects, the availability of debt or equity financing, and the results of our activities. We anticipate spending a minimum of approximately $2,000,000 on exploration and development activities during our fiscal year ending August 31, 2005. To limit capital expenditures, we intend to form industry alliances and exchange an appropriate portion of our interest for cash and/or a carried interest in our exploration projects. We may need to raise additional funds to cover capital expenditures. These funds may come from cash flow, equity or debt financings, a credit facility, or sales of interests in our properties, although there is no assurance additional funding will be available or that it will be available on satisfactory terms. Capital Expenditures During fiscal 2004, we incurred approximately $3,823,000 of capital costs related to the properties we acquired from Venus Exploration, Inc. This amount includes capitalized acquisition costs, costs associated with undeveloped leasehold, drilling, workover, and geological and geophysical costs. We incurred approximately $1,570,000 for costs related to our other exploration projects including continued acreage lease obligations and associated geological and geophysical costs, as well as drilling costs for the Mallard well. Revenues from oil and gas production during 2004 were approximately $863,000. During fiscal 2004, the Company signed an Exploration Option Agreement with Suncor Energy Natural Gas America, Inc. ("SENGAI"), covering our Rogers Pass exploration project in the Foothills of west-central Montana. Pursuant to our agreement, SENGAI paid us a (non-refundable) $500,000 option fee for a technical evaluation period of up to three months. At August 31, 2004, SENGAI elected to proceed to drill the first test well, and we received the $750,000 election fee in early September 2004 (this amount is recorded as a receivable at August 31, 2004). Also during fiscal 2004, we entered into an agreement with two private oil and gas exploration companies covering two of our exploration projects in the Overthrust of southwestern Wyoming. In conjunction with this agreement, the partners paid us $631,585 in prospect fees and pro-rata development costs. All of the above proceeds were credited to the full cost pool as of August 31, 2004, pursuant to the full cost accounting method of accounting for oil and gas activities. The receipt of such funds allows the Company to lower the risk and capital costs associated with the exploration of significant undeveloped acreage. 24 During fiscal 2003, we incurred approximately $451,000 of capital costs relating to our East Lost Hills Project. We incurred approximately $1,023,000 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 2003 were $195,000. We currently anticipate that we will participate in the drilling of up to four exploration wells during our fiscal year ending August 31, 2005, 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. The following table summarizes the Company's obligations and commitments, as of August 31, 2004 to make future payments under its convertible notes payable and office lease for the periods specified: Payments Due By Period Contractual Year Ended Fiscal Years Fiscal Years Fiscal Years Obligations Total August 31, 2005 2006-2008 2009-2010 2011 and After ---------- ----- -------------- --------- --------- ------------- Convertible Notes $8,474,313 $ -- $ -- $8,474,313 $ -- Office Lease, Denver, CO 210,219 46,715 163,504 -- -- Office Lease, San Antonio, TX 36,000 36,000 -- -- -- Copier Lease 2,331 2,331 -- -- -- Subscriber Agreement to Computer Service 13,475 13,475 -- -- -- ---------- ---------- ---------- ---------- ------- Total Contractual Cash Obligations $8,736,338 $ 98,521 $ 163,504 $8,474,313 $ -- The above schedule assumes convertible note interest payments will be added to the principal amount (which is at the discretion of the Company), and the entire balance will be paid in full on maturity of May 24, 2009, and there will be no conversion of debt to common stock. In addition to the above obligations, if we elect to continue holding all our existing leases on a delayed rental basis, we would have to pay approximately $490,000 during the year ending August 31, 2005. The Company considers on a quarterly basis whether to continue holding all or part of each acreage block by making delay rental payments on existing leases. Results of Operations The twelve months ended August 31, 2004 ("2004") compared with the twelve months ended August 31, 2003 ("2003") Operations during the fiscal year ended August 31, 2004 resulted in a net loss of $1,359,354 compared to a net loss of $5,237,613 for the fiscal year ended August 31, 2003. Oil and Gas Revenues and Expenses. During the year ended August 31, 2004, we recorded $863,087 in total oil and gas revenues. Of this amount, we recorded $333,769 from the sale of 60,285 mcf of natural gas for an average price of $5.54 per mcf, and $529,318 from the sale of 13,973 bbls of hydrocarbon liquids for an average price of $37.88 per bbl. The portion of fiscal year 2004 oil and gas revenues related to the May 2004 property acquisition from Venus Exploration, Inc. ("Venus"), was $694,182. As the acquisition from Venus was 25 recorded as a purchase transaction, only four months of operations related to these properties were recorded in 2004. During the year ended August 31, 2003, we recorded $153,479 from the sale of 34,773 mcf of natural gas for an average price of $4.41 per mcf, and $41,688 for the sale of 1,583 bbls of hydrocarbon liquids for an average price of $26.33 per bbl. 2003 revenues relate totally to the Company's interest in East Lost Hills in California. Comparable revenues for this prospect in 2004 were $168,905. Lease operating expenses in 2004 were $335,508 compared to $95,334 in 2003. Interest Income. We recorded $27,431 and $53,520 in interest income for the years ended August 31, 2004 and 2003, respectively. Lower interest income in 2004 resulted from lower average cash balances for the majority of 2004, offset partially by interest on the funds received from the private placement of our common stock in May 2004. General and Administrative Expenses. General and administrative expenses in 2004 were $1,324,079 compared to $1,265,912 in 2003. The increase principally reflects additional audit and legal fees incurred in conjunction with the property acquisition from Venus Exploration Inc. Depreciation Depletion and Amortization. We recorded $46,386 in depreciation, depletion and amortization expense from oil and gas properties for the year ended August 31, 2004. We recorded no depreciation, depletion and amortization expense from oil and gas properties for the year ended August 31, 2003, due to an impairment taken against our entire amortizable full cost pool at August 31, 2003, and accordingly, there were no costs to amortize. The increase in depreciation, depletion and amortization expense was attributable to the properties acquired from Venus Exploration, Inc. We recorded $13,111 and $11,191 in depreciation expense associated with capitalized office furniture and equipment during 2004 and 2003, respectively. Depreciation of Asset Retirement Obligation assets for the years ended August 31, 2004 and August 31, 2003, was $113,462 and $151,284, respectively. For further discussion of the Asset Retirement Obligation, see Note 4 to the Financial Statements included in this Form 10-KSB. Accretion Expense. We recorded $99,684 and $76,918, respectively, for the years ended August 31, 2004 and August 31, 2003, of accretion of the unamortized discount of the Asset Retirement Obligation liability. The increase in accretion expense was attributable to the properties acquired from Venus Exploration, Inc. For further discussion of the Asset Retirement Obligation, see Note 4 to the Financial Statements included in this Form 10-KSB. Dry Hole, Impairment and Abandonments. We recorded no impairment expense for the year ended August 31, 2004. For the year ended August 31, 2003, we recorded an impairment expense of $3,234,029, of which $451,285 related to costs incurred in the East Lost Hills prospect, and the remainder, $2,782,744, related to other undeveloped prospects in California and the Rocky Mountain region, which were determined by management to be impaired as of August 31, 2003. Interest Expense. During 2004, we recorded interest expense of $326,886 compared to $310,457 in 2003. The interest expense for each year is associated with the May 24, 2002 sale of outstanding convertible notes due on May 24, 2009. The Company elected to add $319,376 and $303,975 of accrued interest to the balance of the debt for the years ended August 31, 2004 and August 31, 2003, respectively. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our August 31, 2004 and 2003 balance sheets. The twelve months ended August 31, 2003 ("2003") compared with the twelve months ended August 31, 2002 ("2002") Operations during the fiscal year ended August 31, 2003 resulted in a net loss of $5,237,613 compared to a net loss of $13,129,828 for the fiscal year ended August 31, 2002. Oil and Gas Revenues and Expenses. During the year ended August 31, 2003, we recorded $153,479 from the sale of 34,773 mcf of natural gas for an average price of $4.41 per mcf, and $41,688 for the sale of 1,583 bbls of hydrocarbon liquids for an average price of $26.33 per bbl. During the year ended August 31, 2002, we recorded $106,637 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 bbl. Lease operating expenses in 2003 were $95,334 compared to $91,384 in 2002. Interest Income. We recorded $53,520 and $145,645 in interest income for the years ended August 31, 2003 and 2002, respectively. Lower interest income in 2003 resulted from lower average cash balances in 2003 than in 2002, as cash was utilized throughout 2003 to fund the Company's operations. 26 General and Administrative Expenses. General and administrative expenses in 2003 were $1,265,912 compared to $1,496,329 in 2002. The lower expense in 2003 reflects reduced salary and wage expenses following staff resignations, and lower costs incurred for financial advisory services in 2003 compared to 2002. Depreciation Depletion and Amortization. We recorded no depreciation, depletion and amortization expense from oil and gas properties for the years ended August 31, 2003 and August 31, 2002. The ELH#1 well continued producing throughout 2003 and 2002; however, because we have recorded an impairment against our entire amortizable full cost pool at both August 31, 2003 and 2002 there were no costs to amortize. We recorded $11,191 and $14,605 in depreciation expense associated with capitalized office furniture and equipment during 2003 and 2002, respectively. Included in depreciation expense reported for 2003, is $151,284 of depreciation of Asset Retirement Obligation assets. For further discussion of the Asset Retirement Obligation, see Note 4 to the Financial Statements included in this Form 10-KSB. Accretion Expense. We recorded $76,918 and $0, respectively, for the years ended August 31, 2003 and August 31, 2002, of accretion of the unamortized discount of the Asset Retirement Obligation liability. For further discussion of the Asset Retirement Obligation, see Note 4 to the Financial Statements included in this Form 10-KSB. Dry Hole, Impairment and Abandonments. In 2003 we recorded an impairment expense of $3,234,029, of which $451,285 related to costs incurred in the East Lost Hills prospect, and the remainder, $2,782,744, related to other undeveloped prospects in California and the Rocky Mountain region, which were determined by management to be impaired as of August 31, 2003. 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 2002 impairment charge related 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. Interest Expense. During 2003, we recorded interest expense of $310,457 compared to $82,894 in 2002. The increase reflects the existence of $6,000,000 in convertible notes for the entirety of 2003 compared to only 3.25 months of 2002. 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 option of the Company. During 2003, the Company elected to add $303,975 of accrued interest to the balance of the debt. We have reflected the outstanding balance of these notes as Convertible Notes under Long Term Debt on our August 31, 2003 and 2002 balance sheets. Cash Flow The fiscal year ended August 31, 2004 ("2004") compared with the fiscal year ended August 31, 2003 ("2003") Cash Flows From Operating Activities Net cash used by operating activities was $1,087,131 and $1,180,944 for the fiscal years ended August 31, 2004 and August 31, 2003, respectively. A discussion of these and other items are presented below. Net loss. See discussion of net loss in "Results of Operations" section above. Depreciation and amortization. Depreciation and amortization expense increased to $172,959 for the year ended August 31, 2004, compared to $162,475 for the year ended August 31, 2003. The 2004 expense includes depreciation of Asset Retirement Obligation assets of $113,462, and $46,386 of depletion of oil and gas properties. The increase in fiscal 2004 is due to certain properties acquired in May 2004 from Venus Exploration, Inc. The 2003 expense includes depreciation of Asset Retirement Obligation assets of $151,283, and $76,917 of accretion of unamortized discount of the Asset Retirement Obligation liability. The increase in fiscal 2003 is due to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations". For further discussion of the Asset Retirement Obligation, see the Notes to the Financial Statements included in this Form 10-KSB. 27 Impairment, dry hole and abandonments. During the year ended August 31, 2004, we recorded no impairment expense as compared to $3,234,029 during the year ended August 31, 2003. The 2003 impairment related principally to costs incurred to drill and complete wells in the East Lost Hills project. Accounts receivable. For the years ended August 31, 2004 and August 31, 2003, accounts receivable increased $477,176 and $0, respectively. The increase in 2004 related principally to receivables generated from the properties acquired from Venus Exploration, Inc. in May 2004. Accrued interest converted into debt. For the year ended August 31, 2004, accrued interest converted into debt was $319,376 compared to $303,975 for the year ended August 31, 2003. Both amounts reflect interest accrued on the $6,000,000 convertible notes issued May 24, 2002. Accretion of asset retirement obligation. During the years ended August 31, 2004 and August 31, 2003, accretion of unamortized discount of the Asset Retirement Obligation liability was $99,684 and $76,918, respectively. The increase in fiscal 2004 is due to certain properties acquired in May 2004 from Venus Exploration, Inc. The increase in fiscal 2003 is due to the adoption of SFAS 143, "Accounting for Asset Retirement Obligations". For further discussion of the Asset Retirement Obligation, see the Notes to the Financial Statements included in this Form 10-KSB. Prepaid expenses and other. During the year ended August 31, 2004, prepaid expenses increased $45,680, compared to a decrease of $805 during the year ended August 31, 2003. The increase in 2004 primarily reflects higher director and officer liability insurance premiums. Accounts payable and accruals. During the year ended August 31, 2004, accounts payable and accruals increased $209,873 compared to a decrease of $25,895 during the year ended August 31, 2003. The change primarily reflects increased payables activity as a result of the properties acquired from Venus in May 2004. Cash Flows From Investing Activities Cash paid for oil and gas properties. During the year ended August 31, 2004, we paid $5,103,383 for oil and gas properties, compared to $1,670,943, during the year ended August 31, 2003. The increase in 2004 principally reflects the acquisition of properties from Venus in May 2004. Proceeds from sale of exploration options. During the year ended August 31, 2004, we signed an Exploration Option Agreement with Suncor Energy Natural Gas America, Inc. ("SENGAI"), covering our Rogers Pass exploration project in the Foothills of west-central Montana. Pursuant to our agreement, SENGAI paid us a (non-refundable) $500,000 option fee for a technical evaluation period of up to three months. At August 31, 2004, SENGAI elected to proceed to drill the first test well, and we received the election fee in early September 2004. We received $0 in proceeds from the sale of exploration options during the year ended August 31, 2003. Proceeds from sale of oil and gas properties. During the year ended August 31, 2004, we entered into an agreement with two private oil and gas exploration companies covering two of our exploration projects in the Overthrust of southwestern Wyoming. In conjunction with this agreement, the partners paid us $631,585 in prospect fees and pro-rata development costs. We received $0 in proceeds from the sale of oil and gas properties during the year ended August 31, 2003. Cash Flows From Financing Activities Cash provided by financing activities was $7,449,681 and $0 for the years ended August 31, 2004 and August 31, 2003, respectively. The increase in 2004 primarily reflects the private placement sale of 7.5 million shares of common stock, priced at $1.09 per share, to a group of twelve institutional and accredited individual investors pursuant to exemptions from registration under Sections 3(b) and 4(2) of the Securities Exchange Act of 1934, as amended. 28 Critical Accounting Policies And Estimates We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our Financial Statements. Reserve Estimates: Our estimates of oil and natural gas reserves, by necessity, are projections based on geological and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future operating costs, severance and excise taxes, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows expected from there may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of the oil and gas properties. Actual production, revenues and expenditures with respect to our reserves will likely vary from estimates, and such variances may be material. Many factors will affect actual net cash flows, including the following: the amount and timing of actual production; supply and demand for natural gas; curtailments or increases in consumption by natural gas purchasers; and changes in governmental regulations or taxation. Property, Equipment and Depreciation: We follow the full cost method to account for our oil and gas exploration and development activities. Under the full cost method, all costs incurred which are directly related to oil and gas exploration and development are capitalized and subjected to depreciation and depletion. Depletable costs also include estimates of future development costs of proved reserves. Costs related to undeveloped oil and gas properties may be excluded from depletable costs until those properties are evaluated as either proved or unproved. The net capitalized costs are subject to a ceiling limitation based on the estimated present value of discounted future net cash flows from proved reserves. As a result, we are required to estimate our proved reserves at the end of each quarter, which is subject to the uncertainties described in the previous section. Gains or losses upon disposition of oil and gas properties are treated as adjustments to capitalized costs, unless the disposition represents a significant portion of the Company's proved reserves. Revenue Recognition: The Company recognizes oil and gas revenues from its interests in producing wells as oil and gas is produced and sold from these wells. The Company has no gas balancing arrangements in place. Oil and gas sold is not significantly different from the Company's product entitlement. Recent Accounting Pronouncements In June 2001, the FASB issued SFAS No. 141, "Business Combinations" ("SFAS No. 141") and SFAS No. 142, "Goodwill and Intangible Assets" ("SFAS No. 142"). SFAS Nos. 141 and 142 became effective on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. One interpretation that was considered relative to these standards was that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such 29 reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on the Company's consolidated balance sheets. In April 2004, the Financial Accounting Standards Board amended SFAS Nos. 141 and 142 and clarified the interpretation by defining mineral rights, such as oil and gas mineral rights, as tangible assets. Accordingly, the guidelines for accounting for intangible assets as provided in SFAS No. 142 would not apply to oil and gas mineral rights. In accordance with this new guideline, the Company will continue to classify its contractual rights to extract oil and gas reserves as tangible oil and gas properties. ITEM 7. FINANCIAL STATEMENTS The Consolidated Financial Statements and schedules that constitute Item 7 are attached at the end of Annual Report on Form 10-KSB. An index to these Financial Statements and schedules is also included in Item 14(a) of this Annual Report on Form 10-KSB. ITEM 8. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE As previously reprinted in the Company's Form 8-K, the Company changed auditors in 2004. There were no disagreements with either of our auditors on accounting or financial disclosures. ITEM 8A. CONTROLS AND PROCEDURES As of the end of the period covered by this report, the Company conducted an evaluation of the Company's disclosure controls and procedures (as defined in Rules 13a-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act")). Based on this evaluation, the Company concluded that, subject to the limitations described below, the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in annual reports that it files under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in Securities and Exchange Commission rules and forms. There was no change in the Company's internal controls over financial reporting during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting period. In connection with the audit of the Company's financial statement for the fiscal year ended August 31, 2004, the independent auditors informed the Company that they had discovered a material weakness in the Company's internal control over financial reporting. The material weakness consists of the Company's failure to record within its general ledger on a timely basis the issuance of common stock and warrants.

The financial implication of this inadvertent oversight was an increase in stockholders' equity and oil and gas property by approximately $372,000. The impact on net loss and net loss per share was negligible. On an interim basis, the Company has instituted the following corrective action: the Chairman of the Compensation Committee will make direct contact with the Vice President of Strategic Development to report any issuance of common stock, warrants, options, or other securities for recording in the Company's general ledger. Going forward, the Company intends to implement changes promptly to address this issue. The Company will consider implementing the following corrective actions as well as additional procedures: o Establishing procedures for the timely and direct reporting by the Board's Compensation Committee to the finance department upon the granting of common stock, warrants, options, or other securities; and o The assignment of a specific individual to communicate with the Compensation Committee and report on the same day grants of common stock, warrants, options, or other securities to those officers and directors required to file changes in beneficial ownership reports under Section 16 of the Exchange Act with the Securities and Exchange Commission. The Company will continue to evaluate the effectiveness of its disclosure controls and internal controls and procedures on an ongoing basis, and will take further action as appropriate. 30 ITEM 8B. OTHER INFORMATION Not applicable. PART III ITEM 9. DIRECTORS, EXECUTIVE OFFICERS, PROMOTERS AND CONTROL PERSONS; COMPLIANCE WITH SECTION 16(a) OF THE EXCHANGE ACT The directors and executive officers of the Company, their respective positions and ages, and the year in which each director was first elected, are set forth in the following table. Each director has been elected to hold office until the next annual meeting of stockholders and thereafter until his successor is elected and has qualified. Additional information concerning each of these individuals follows the table. Name Age Position with the Company Director Since ---- --- ------------------------ ------------- D. Scott Singdahlsen 46 Chief Executive Officer, Chief Financial 1997 Officer, President, and Chairman Of the Board David Kilpatrick 54 Director 2002 Bryce W. Rhodes 51 Director 1999 Dennis M. Swenson 69 Director 2004 Tucker L. Franciscus 36 Vice President Strategic Development --- Kenneth R. Berry, Jr. 52 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. 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 oil and gas industry. He currently serves as a Director of the publicly traded Cheniere Energy and privately held Ensyn Petroleum International, Ltd. Prior to the 1998 merger with Texaco, he was President and Chief Operating Officer of Monterey Resources, Inc., the largest independent oil and gas producer in California. Mr. Kilpatrick has served as President of the California Independent Petroleum Association and is a member of its Board of Directors and also serves as a Director of the Independent Oil Producers Agency. He earned a Bachelor of Science degree in Petroleum Engineering from the University of Southern California and a Bachelor's Degree in Geology and Physics from Whittier College. Bryce W. Rhodes has been a Director of the Company since April 1999, when he was nominated and elected to the Board in connection with the sale by the Company of convertible promissory notes issued in a private placement 31 transaction in October and November 1998. From 1996 until September 2003, Mr. Rhodes has served as President and CEO of Whittier Energy Company ("WEC"), an oil and gas investment company. In September 2003, WEC merged with Olympic Resources, Inc. and Mr. Rhodes was appointed as President and Chief Executive Officer. Mr. Rhodes served as Investment Manager of WEC from 1990 until 1996. Mr. Rhodes received B.A. degrees in Geology and Biology from the University of California, Santa Cruz, in 1976 and an MBA degree from Stanford University in 1979. Dennis M. Swenson joined as a Director in October 2004, and serves as the Audit Committee Chairman and a member of the Compensation Committee. From 1992 through 1995, Mr. Swenson was an independent consultant. Mr. Swenson was Executive Vice President, Chief Financial Officer, Secretary and Treasurer, of StarTek, Inc., a NYSE traded company with headquarters in Denver, Colorado from 1996 through retirement in 2001. Mr. Swenson was employed at Ernst & Young in Denver from 1960 to 1973, and was a partner at Ernst & Young from 1973 to 1991. He has a Bachelor's Degree in Accounting from Brigham Young University and an MBA Degree from the University of Denver. Tucker L. Franciscus, Vice President of Strategic Development, joined PYR in September 2004. Mr. Franciscus joined the firm from Stifel Nicolaus & Company, where he oversaw their Investment Banking Energy Group practice between 2001 and 2004. Mr. Franciscus was responsible for mergers and acquisitions, equity and debt offerings, and private placements for all of Stifel's energy clients. Prior to working at Stifel, Mr. Franciscus was the senior associate and manager for the Global Energy Group at J.P. Morgan in New York and an associate in the Deutsche Banc BT Wolfensohn Mergers & Acquisitions Group. Mr. Franciscus has executed equity, debt, mergers and acquisitions and other financing transactions in various industries including defense, energy, media and telecom. For five years preceding his banking experience, Mr. Franciscus worked in various marketing and finance positions in the oil and gas sector, including Synder Oil and KN Energy (Interenergy). Additionally, he was a commissioned Infantry Officer in the U.S. Army and continues to serve in the reserves. Mr. Franciscus has an MBA from the Daniels college of Business at the University of Denver and a Bachelor of Arts from Ohio Wesleyan University. 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, 2004, its officers, directors and holders of more than 10% of the Company's common stock complied with all Section 16(a) filing requirements, except that Ken Berry, a Vice President, was late filing a Form 4 with respect to his receipt of stock options on September 9, 2003 and August 26, 2004. 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, 2004 on behalf of the Company's directors, officers and holders of more than 10% of the Company's common stock. Employee Code of Conduct and Code of Ethics and Reporting of Accounting Concerns The Company adopted an Employee Code of Conduct (the "Code of Conduct"). We require all employees to adhere to the Code of Conduct in addressing legal and ethical issues encountered in conducting their work. The Code of Conduct requires that our employees avoid conflicts of interest, comply with all laws and other legal requirements, conduct business in an honest and ethical manner and otherwise act with integrity and in the Company's best interest. The Company also adopted a Code of Ethics for our Chief Executive Officer, our Chief Financial Officer, our Controller and all other financial officers and executives. This Code of Ethics supplements our Code of Conduct and is intended to promote honest and ethical conduct, full and accurate reporting, and compliance with laws as well as other matters. The Code of Conduct and Code of Ethics are filed with the SEC as exhibits to this Annual Report. 32 Further, the Audit Committee of the Board of Directors has established "whistle-blower procedures" which provides a process for the confidential and anonymous submission, receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters. These procedures provide substantial protections to employees who report company misconduct. Audit Committee Financial Expert The Company's Board of Directors has determined that Mr. Dennis M. Swenson is the Company's audit committee financial expert. Identification of Audit Committee The Board of Directors currently has an Audit Committee consisting of Messrs. Swenson (Chairman), Kilpatrick and Rhodes. The Audit Committee is responsible for the selection and retention of our independent auditors, reviews the scope of the audit functions of the independent auditor, and reviews audit reports rendered by our independent auditors. The Audit Committee oversees the Company's financial reporting process on behalf of the Board of Directors. Management has the primary responsibility for the financial statements, accounting policies and procedures, and the reporting process, including the systems of internal controls. In fulfilling its oversight responsibilities, the Committee reviewed and discussed with management the audited financial statements in this Annual Report on Form 10-KSB for the year ended August 31, 2004 and the unaudited financial statements included in the Quarterly Reports on Form 10-Q for the first three quarters of the fiscal year ended August 31, 2004. ITEM 10. 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, 2004 by D. Scott Singdahlsen, our Chief Executive

Officer, President, Chief Financial Officer and Chairman of The Board. Other than Mr. Singdahlsen, none of our executive officers received total salary and bonus exceeding $100,000 during the last the fiscal year ended August 31, 2004. Summary Compensation Table -- Annual Compensation Long-Term Compensation -- --- Awards Payouts ------------------------ -------- Other Annual Restricted Securities LTIP All Other Fiscal Salary Bonus Compensation Stock Underlying Payouts Compensation Name and Principal Position Year ($)(1) ($)(2) ($)(3) Awards ($) Options(#) ($)(4) ($)(5) -------------------------- ---- ------ ------ ------ ---------- ---------- ------ ------ D. Scott Singdahlsen 2004 $175,000 $-0- -0- -0- -0- -0- -0- Chief Executive Officer, Chief Financial Officer, 2003 $175,000 $-0- -0- -0- 281,750 -0- -0- President and Chairman Of the Board 2002 $175,000 $-0- -0- -0- -0- -0- -0- (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. 33 (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 There were no individual grants of stock options made during the fiscal year ended August 31, 2004 to any executive officers. However, since the end of the fiscal year, Mr. Singdahlsen has received 200,000 shares with an exercise price of $0.96 that expire in 2014. One fifth are exercisable each November for the next five years. Aggregated Option Exercises And Fiscal Year-End Option Value Table The following table provides certain summary information concerning stock option exercises during the fiscal year ended August 31, 2004 by the named executive officer and the value of unexercised stock options held by the named executive officer as of August 31, 2004. Aggregated Option Exercises in last Fiscal Year And Year-End Option Values(1) -- Number of Securities Underlying Unexercised Value of Unexercised Options at Fiscal In-the-Money Options at Year-End (#)(4) Fiscal Year-End ($)(5) --------------------------- -------------------------- Shares Acquired Value Realized Name on Exercise(2) ($)(3) Exercisable Unexercisable Exercisable Unexercisable ---- ------------- ------ ---------- ------------ ----------- ------------ D. Scott Singdahlsen $-0- $-0- 303,917 192,833 $-0- $38,667 (1) No stock appreciation rights are held by any of the named executive officers. (2) The number of shares received upon exercise of options during the year ended August 31, 2004. (3) With respect to options exercised during the year ended August 31, 2004, the dollar value of the difference between the option exercise price and the market value of the option shares purchased on the date of the exercise of the options. (4) The total number of unexercised options held as of August 31, 2004, separated between those options that were exercisable and those options that were not exercisable on that date. (5) For all unexercised options held as of August 31, 2004, the aggregate dollar value of the excess of the market value of the stock underlying those options over the exercise price of those unexercised options. These values are shown separately for those options that were exercisable and those options that were not yet exercisable on August 31, 2004 based on the closing sale price of our common stock on the last business day before that date, which was $0.87 per share. 34 Employee Retirement Plans, Long-Term Incentive Plans and Pension Plans Excluding the Company's stock option plans, we do not have any long-term incentive plan to serve as incentive for performance to occur over a period longer than one fiscal year. 1997 Stock Option Plan In August 1997, our 1997 Stock Option Plan (the "1997 Plan") was adopted by the Board of Directors and subsequently approved by the stockholders. Pursuant to the 1997 Plan, we may grant options to purchase an aggregate of 1,000,000 shares of common stock to key employees, directors, and other persons who have contributed or are contributing to our success. The options granted pursuant to the 1997 Plan may be either incentive options qualifying for beneficial tax treatment for the recipient or they may be nonqualified options. The 1997 Plan may be administered by the Board of Directors or by an option committee. Administration of the 1997 Plan includes determination of the terms of options granted under the 1997 Plan. At August 31, 2004, options to purchase 90,000 shares were outstanding under the Plan and 626,500 options were available to be granted under the 1997 Plan. 2000 Stock Option Plan In March 1999, our 2000 Stock Option Plan (the "2000 Plan") was adopted by the Board of Directors and subsequently approved by the stockholders. Pursuant to the 2000 Plan, we may grant options to purchase shares of our common stock to key employees, directors, and other persons who have contributed or are contributing to our success. We initially could grant options to purchase up to 500,000 shares pursuant to the 2000 Plan. In June 2001, our stockholders approved an amendment which allows us to grant options to purchase up to 1,500,000 shares pursuant to the 2000 Plan. In June 2004, our stockholders approved an amendment to increase from 1,500,000 to 2,250,000 the number of shares of common stock issuable pursuant to options granted under the 2000 Plan. The options granted pursuant to the 2000 Plan may be either incentive options qualifying for beneficial tax treatment for the recipient or non-qualified options. The 2000 Plan may be administered by the Board of Directors or by an option committee. Administration of the 2000 Plan includes determination of the terms of options granted under the 2000 Plan. As of August 31, 2004, options to purchase 2,093,834 shares were outstanding under the 2000 Plan and 90,000 options were available to be granted pursuant to the 2000 Plan. Compensation Committee Interlocks and Insider Participation The Compensation Committee is made up of three directors: Messrs. Swenson, Kilpatrick and Rhodes. None of the members of the Committee have been executive officers of the Company. In addition, no member of the Committee is, or was during the fiscal year ended August 31, 2004, an executive officer of another company whose board of directors has a comparable committee on which one of the Company's executive officers serves. Employment Contracts And Termination of Employment And Change-In-Control Arrangements We do not have any written employment contracts with any of our officers or other employees. We have no compensatory plan or arrangement that results or will result from the resignation, retirement, or any other termination of an executive officer's employment or from a change-in-control or a change in an executive officer's responsibilities following a change-in-control, except that both the 1997 Plan and the 2000 Plan provide for vesting of all outstanding options in the event of the occurrence of a change-in-control. ITEM 11. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS Stock Ownership Of Directors And Principal Stockholders As of November 19, 2004, there were 31,564,426 shares of common stock outstanding. The following table sets forth certain information as of that date with respect to the beneficial ownership of common stock by each director and nominee for director, by all executive officers and directors as a group, and by each other person known by us to be the beneficial owner of more than five percent of our outstanding shares of common stock: 35 Number of Shares Percentage of Name and Address of Beneficial Owner Beneficially Owned(1) Shares Outstanding ---------------------------------- -------------------- ------------------ D. Scott Singdahlsen 2,053,917(2) 6.5% 1675 Broadway, Suite 2450 Denver, Colorado 80202 Bryce W. Rhodes 122,414(3) * c/o Whittier Energy Company 7770 El Camino Real Carlsbad, CA 92009 David B. Kilpatrick 45,000(4) * 9105 St. Cloud Lane Bakersfield, CA 93311 Dennis M. Swenson 25,000(5) * 5360 Lakeshore Drive Littleton, CO 80123 All Executive Officers and Directors as a group 2,592,896(1)(2)(3)(4)(5)(6) 8.0% (five persons) Victory Oil Company 2,978,428(7) 9.4% 222 West Sixth Street, Suite 1010 San Pedro, California 90731 Eastbourne Capital Management, L.L.C. 7,141,329(8) 22.6% 1101 Fifth Avenue, Suite 160 San Rafael, CA 94901 --------------------------- (*) Less than one percent. (1) "Beneficial ownership" is defined in the regulations promulgated by the U.S. Securities and Exchange Commission as having or sharing, directly or indirectly (1) voting power, which includes the power to vote or to direct the voting, or (2) investment power, which includes the power to dispose or to direct the disposition of shares of the common stock of an issuer. The definition of beneficial ownership includes shares underlying options or warrants to purchase common stock, or other securities convertible into common stock, that currently are exercisable or convertible or that will become exercisable or convertible within 60 days. Unless otherwise indicated, the beneficial owner has sole voting and investment power. (2) The shares shown for Mr. Singdahlsen include 200,000 shares owned by Mr. Singdahlsen's two minor children. Also includes options to purchase 100,000 shares at $4.40 per share until May 15, 2005, options to purchase 100,000 shares at $5.98 per share until November 27, 2005, options to purchase 10,000 shares at $1.82 per share until April 12, 2007, options to purchase 66,667 shares at $0.29 per share until February 4, 2010, and options to purchase 27,250 shares at $1.30 per share until February 4, 2010. (3) Includes 13,000 shares of common stock owned by Mr. Rhodes and 64,414 shares of common stock owned by Adventure Seekers Travel, Inc. Adventure Seekers is owned by Mr. Rhodes' wife and Mr. Rhodes is the President of Adventure Seekers. Also includes options to purchase 20,000 shares at $1.65 per share until April 11, 2007 and options to purchase 25,000 shares at $1.15 per share until October 14, 2009 that currently are exercisable. 36 Excludes 171,625 shares that are held by Whittier Energy Company. Mr. Rhodes is a President and CEO of Whittier Energy Company.

Mr. Rhodes disclaims beneficial ownership of the shares beneficially owned by Whittier Energy Company (4) Includes options to purchase 20,000 shares at $1.72 per share until June 4, 2007, and options to purchase 25,000 shares at $1.15 per share until October 14, 2009 that currently are exercisable that are owned by Mr. Kilpatrick. (5) Includes options to purchase 25,000 shares at $1.24 per share until October 1, 2009 that are exercisable. The options expire five years from the date that they become exercisable by Mr. Swenson. (6) Includes the following securities held directly or indirectly by Kenneth R. Berry, Jr., who is Vice President of Land: an aggregate of 84,065 shares owned by various entities, IRAs, and trusts with which Mr. Berry, or his spouse or minor daughter, is associated; and options to purchase 262,500 shares of common stock at exercise prices ranging from $.29 to $5.44 per share that currently are exercisable or that will become exercisable within the next 60 days. (7) Based on information contained in an amendment to Schedule 13D filed with the SEC on July 16, 2001. (8) Based on information contained in an amendment to Schedule 13D filed with the SEC on March 3, 2004. The shares reflected include the shares beneficially owned by Eastbourne Capital Management, L.L.C., a registered investment adviser, Richard Jon Barry, Manager of Eastbourne and the following companies to which Eastbourne is investment adviser: Black Bear Offshore Master Fund Limited, a Cayman Island exempted company, Black Bear Fund I, L.P. and Black Bear Fund II, LLC. These shares include the equivalent shares of common stock underlying $6,303,975 of convertible notes held by Black Bear Offshore Master Fund Limited, Black Bear Fund I, L.P. and Black Bear Fund II, LLC. ITEM 12. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS On May 24, 2002, certain investment entities managed by Eastbourne Capital Management, LLC purchased $6 million of convertible notes from the Company. The notes provide for semi-annual interest payments at an annual rate of 4.99% and are convertible into common stock at the rate of $1.30 per share. At the time of the transaction, these entities had aggregate ownership in PYR Energy Corporation of approximately 15%. Concurrent with the sale, we agreed to add Messrs. Eric Sippel and Borden Putnam, of Eastbourne, to our Board of Directors. Messrs. Sippel and Putnam resigned from the board in August 2003, although Eastbourne still has the right to designate two individuals to serve on the Board. During the fiscal year ended August 31, 2004, there were no other transactions between the Company and its directors, executive officers or known holders of greater than five percent of the Company's common stock in which the amount involved exceeded $60,000 and in which any of the foregoing persons had or will have a material interest. ITEM 13. EXHIBITS Exhibit Index Number Description ------ ----------- 3.1 Articles Of Incorporation filed with the Maryland Secretary Of State on June 18, 2001.(1) 3.2 Articles of Merger filed with the Maryland Secretary Of State on July 3, 2001 in connection with Maryland reincorporation.(1) 3.3 Bylaws(1) 31 Rule 13a - 14(a) Certifications of Chief Executive Officer and Chief Financial Officer 32 Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 37 99.1 Employee Code of Conduct 99.2 Code of Ethics for Chief Executive Officer, Chief Financial Officer and Controller ---------- (1) Incorporated by reference from the Registrant's Form 10-KSB for the year ended August 31, 2001. ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES Audit Fees Hein + Associates, LLP, the Company's principal accountants, billed the Company $47,210 for the year ended August 31, 2004. Hein + Associates, LLP was hired in November 2003 as the Corporation's certified independent accountant. Hein's professional services, as of August 31, 2004, included review of financial statements included in the Company's Forms 10-Q, and services provided in connection with regulatory filings. Wheeler Wasoff, P.C., the Company's certified independent accountant prior to November 2003, billed the Company $28,352 for the year ended August 31, 2003, for the audit of the Company's annual financial statements and review of financial statements included in the Company's Forms 10-Q, as well as for services normally provided by Wheeler Wasoff, P.C. in connection with statutory and regulatory filings or engagements for fiscal 2003. In 2004 Wheeler Wasoff, P.C. has been retained to provide guidance on tax matters and other issues as needed. Audit-Related Fees For the year ended August 31, 2004, Hein + Associates, LLP also audited the historical summary of oil and gas operations of Venus Exploration Inc., which was included in a Form 8-K as filed by the Company, and issued currently dated consents in connection with the Company's Form S-3 filings. For these services Hein + Associates LLP, billed the Company $28,757. During 2004 Wheeler Wasoff, P.C. billed the Company $5,300 related to the re-issuance of their 2003 report and issuance of currently dated consents related to the filing of the Company's Form S-3SB registration statements and a transition of auditors. Wheeler Wasoff, P.C. did not provide the Company with any services for assurance and related services that were not reasonably related to the performance of the audit or review of the Company's financial statements and are not reported above under "--Audit Fees." Tax Fees For the years ended August 31, 2004 and August 31, 2003, Wheeler Wasoff, P.C. billed the Company $3,325 and $2,150, respectively, for professional services for tax compliance, tax advice, and tax planning. There were no amounts billed by Hein + Associates, LLP for professional services for tax compliance, tax advice, and tax planning for those fiscal years. All Other Fees For the years ended August 31, 2004 and August 31, 2003, Hein + Associates, LLP and Wheeler Wasoff, P.C. did not bill the Company for products and services other than those described above. Audit Committee Pre-Approval Policies The audit committee currently does not have any pre-approval policies or procedures concerning services performed by Hein + Associates, LLP or Wheeler Wasoff, P.C. All the services performed by Hein + Associates, LLP and Wheeler Wasoff, P.C. that are described above were pre-approved by the audit committee. 38 SIGNATURES In accordance with Section 13 or 15(d) of the Exchange Act, the registrant has caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. PYR ENERGY CORPORATION Date: December 2, 2004 By: /s/ D. Scott Singdahlsen ------------------------------------ D. Scott Singdahlsen Chief Executive Officer In accordance with the requirements of the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. Signatures Title Date --------------------------- -- ---------------- /s/ D. Scott Singdahlsen Chief Executive Officer, President, Chief December 2, 2004 --------------------------- Financial Officer and Chairman Of The Board D. Scott Singdahlsen /s/ Dennis M. Swenson Director December 2, 2004 --------------------- Dennis M. Swenson /s/ David Kilpatrick Director December 2, 2004 --------------------------- David Kilpatrick /s/ Bryce W. Rhodes Director December 2, 2004 --------------------------- Bryce W. Rhodes 39 PYR ENERGY CORPORATION INDEX Report of Independent Public Accounting Firms........................F-2 - F-3 Consolidated Balance Sheets August 31, 2004 and 2003..F-4 Consolidated Statements of Operations Years Ended August 31, 2004 and 2003..............................F-5 Consolidated Statements of Stockholders' Equity For the Period from September 1, 2002.............................F-6 Consolidated Statements of Cash Flows Years Ended August 31, 2004 and 2003........................F-7 - F-8 Notes to Consolidated Financial Statements..........................F-9 - F-20 F-1 REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM To the Board of Directors PYR Energy Corporation Denver, Colorado We have audited the consolidated balance sheet of PYR Energy Corporation and subsidiaries as of August 31, 2004, and the related consolidated statements of operations, stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provided a reasonable basis for our opinion. In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of PYR Energy Corporation and subsidiaries as of August 31, 2004, and the results of their operations and their cash flows for the year then ended August 31, 2004, in conformity with U.S. generally accepted accounting principles. /s/ HEIN & ASSOCIATES LLP ------------------------ HEIN & ASSOCIATES LLP Denver, Colorado November 10, 2004 F-2 REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM To The Board of Directors and Stockholders PYR ENERGY CORPORATION We have audited the accompanying balance sheet of PYR Energy Corporation (a development stage company) as of August 31, 2003, and the related statements of operations, stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of PYR Energy Corporation as of August 31, 2003, and the results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America. /s/ Wheeler Wasoff, P.C. ----------------------- Wheeler Wasoff, P.C. Denver, Colorado

November 25, 2003 F-3 PYR ENERGY CORPORATION CONSOLIDATED BALANCE SHEETS AUGUST 31, ---------------------------- 2004 2003 ------------ ------------ ASSETS CURRENT ASSETS: Cash $ 6,038,156 $ 3,657,938 Oil and Gas Receivables 477,176 -- Other receivable 750,000 -- Prepaid expenses and other assets 102,239 46,559 ------------ ------------ Total current assets 7,367,571 3,704,497 ------------ ------------ PROPERTY AND EQUIPMENT, AT COST Furniture and equipment, net 26,736 29,313 Oil and gas properties under full cost, net 8,851,351 5,287,837 ------------ ------------ 8,878,087 5,317,150 ------------ ------------ OTHER ASSETS: Deferred financing costs and other assets 65,070 68,257 ------------ ------------ 65,070 68,257 ------------ ------------ TOTAL ASSETS $ 16,310,728 $ 9,089,904 ============ ============ LIABILITIES AND STOCKHOLDERS' EQUITY CURRENT LIABILITIES: Accounts payable $ 83,042 $ 25,070 Accrued expenses: Ad valorem tax payable 65,068 69,034 Accrued interest payable 89,644 85,321 Other accrued liabilities 199,688 130,371 ------------ ------------ 354,400 309,796 Asset retirement obligation 868,163 727,231 ------------ ------------ Total current liabilities 1,305,605 1,037,027 ------------ ------------ LONG-TERM LIABILITIES: Convertible Notes 6,623,351 6,303,975 Asset retirement obligation 289,489 118,862 ------------ ------------ Total long-term liabilities 6,912,840 6,422,837 COMMITMENTS AND CONTINGENCIES (Note 8) STOCKHOLDERS' EQUITY: Preferred stock, $.001 par value; authorized 1,000,000 shares; issued and outstanding - none -- -- Common stock, $.001 par value; authorized 75,000,000 shares; issued and outstanding - 31,564,426 at 8/31/04 and 23,701,357 shares at 8/31/03 31,564 23,701 Capital in excess of par value 43,221,391 35,407,657 Accumulated deficit (35,160,672) (33,801,318) ------------ ------------ Total stockholders' equity 8,092,283 1,630,040 ------------ ------------ TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY $ 16,310,728 $ 9,089,904 ============ ============ The accompanying notes are an integral part of the financial statements. F-4 PYR ENERGY CORPORATION CONSOLIDATED STATEMENTS OF OPERATIONS YEARS ENDED AUGUST 31, ---------------------------- 2004 2003 ------------ ------------ REVENUES: Oil and gas revenues $ 863,087 $ 195,167 ------------ ------------ 863,087 195,167 ------------ ------------ OPERATING EXPENSES: Lease operating expenses 335,508 95,334 Accretion expense 99,684 76,918 Impairment -- 3,234,029 Depreciation and amortization 172,959 162,475 General and administrative 1,324,079 1,265,912 ------------ ------------ Total operating expenses 1,932,230 4,834,668 ------------ ------------ LOSS FROM OPERATIONS (1,069,143) (4,639,501) OTHER INCOME (EXPENSE): Interest income 27,431 53,520 Other income 9,244 -- Interest (expense) (326,886) (310,457) ------------ ------------ Total other income (expense) (290,211) (256,937) ------------ ------------ LOSS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE (1,359,354) (4,896,438) Cumulative effect of change in accounting principle -- (341,175) ------------ ------------ NET LOSS $ (1,359,354) $ (5,237,613) ============ ============ NET LOSS PER COMMON SHARE -BASIC AND DILUTED $ (.05) $ (.22) ============ ============ WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING 25,789,698 23,701,357 ============ ============ The accompanying notes are an integral part of the financial statements. F-5 PYR ENERGY CORPORATION CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY PERIOD FROM SEPTEMBER 1, 2002 TO AUGUST 31, 2004 COMMON STOCK CAPITAL IN -------------------------- EXCESS OF ACCUMULATED SHARES AMOUNT PAR VALUE DEFICIT ------------ ------------ ------------ ------------ BALANCE, September 1, 2002 23,701,357 $ 23,701 $ 35,407,657 $(28,563,705) Net (loss) -- -- -- (5,237,613) ------------ ------------ ------------ ------------ BALANCE, August 31, 2003 23,701,357 23,701 35,407,657 (33,801,318) Issuance of common stock and warrants for property and rights to oil and gas technology 311,403 311 371,605 -- Exercise of common stock options for cash 51,666 52 14,931 -- Sale of common stock for cash and underwriter warrants, net 7,500,000 7,500 7,427,198 -- Net (loss) -- -- -- (1,359,354) ------------ ------------ ------------ ------------ BALANCE, August 31, 2004 31,564,426 $ 31,564 $ 43,221,391 $(35,160,672) ============ ============ ============ ============ The accompanying notes are an integral part of the financial statements. F-6 PYR ENERGY CORPORATION CONSOLIDATED STATEMENTS OF CASH FLOWS YEARS ENDED AUGUST 31, -------------------------- 2004 2003 ----------- ----------- CASH FLOWS FROM OPERATING ACTIVITIES: Net loss $(1,359,354) $(5,237,613) Adjustments to reconcile net loss to net cash used by operating activities Cumulative effect of change in accounting principle -- 341,175 Depreciation and amortization 172,959 162,475 Impairment -- 3,234,029 Amortization of financing costs 3,187 3,187 Interest expense converted into debt 319,376 303,975 Accretion of asset retirement obligation 99,684 76,918 Changes in assets and liabilities (Increase) in accounts receivable (477,176) -- (Increase) decrease in prepaids and other receivables (45,680) 805 Increase in accounts payable 57,972 7,898 Increase (decrease) in accrued expenses 151,901 (33,793) Other (10,000) (40,000) ----------- ----------- Net cash used by operating activities (1,087,131) (1,180,944) ----------- ----------- CASH FLOWS FROM INVESTING ACTIVITIES Cash paid for furniture and equipment (10,534) (6,261) Cash paid for oil and gas properties (5,103,383) (1,670,943) Proceeds from sale of exploration options 500,000 -- Proceeds from sale of oil and gas properties 631,585 -- ----------- ----------- Net cash used in investing activities (3,982,332) (1,677,204) ----------- ----------- CASH FLOWS FROM FINANCING ACTIVITIES Proceeds from sale of common stock 8,175,000 -- Proceeds from exercise of options 14,983 -- Cash paid for offering costs (740,302) -- ----------- ----------- Net cash provided by financing activities 7,449,681 -- ----------- ----------- NET INCREASE (DECREASE) IN CASH 2,380,218 (2,858,148) CASH, BEGINNING OF PERIODS 3,657,938 6,516,086 ----------- ----------- CASH, END OF PERIODS $ 6,038,156 $ 3,657,938 =========== =========== The accompanying notes are an integral part of the financial statements. F-7 PYR ENERGY CORPORATION CONSOLIDATED STATEMENTS OF CASH FLOWS (continued) YEARS ENDED AUGUST 31, 2004 AND 2003 SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION During the years ended August 31, 2004 and 2003, the Company made no cash payments for interest or income taxes. SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES During the year ended August 31, 2004, the Company issued warrants to the underwriter, valued at $352,500, as partial consideration for the private placement of common stock; issued common stock, valued at $337,916, for oil and gas properties and technology rights; issued a warrant for common stock, valued at $34,000, for rights to oil and gas technology; sold the rights to drill on one of its properties to a third party for $750,000, which was collected subsequent to year end; and increased the asset retirement obligation by $211,875. During the year ended August 31, 2003, the asset retirement obligation increased by $769,175. The accompanying notes are an integral part of the financial statements. F-8 1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES: --- Organization And Business - PYR Energy Corporation (the "Company") is an independent oil and gas company primarily engaged in the exploration for, acquisition, development and production of, crude oil and natural gas. The Company's current activities are principally conducted in the Rocky Mountains, Texas, and Gulf Coast regions of the United States. On February 18, 2004, PYR Cumberland LLC, PYR Mallard LLC, and PYR Pintail LLC were formed as wholly owned subsidiaries of PYR Energy Corporation. The purpose of these entities is to own and develop certain assets related to designated individual exploration projects. On May 7, 2004, PYR acquired certain oil and gas assets of Venus Exploration, Inc. ("Venus") out of Bankruptcy. The Venus assets acquired include interests in 80 non-operated wells in Utah, Oklahoma and Texas. New drilling and workovers have been conducted since the acquisition date and include two recent discoveries. Prior to this acquisition, the Company was considered to be a development stage Company. As a result of the increased revenues related to the properties acquired, the Company is no longer considered to be a development stage company (see Note 2). Basis Of Presentation - The accompanying consolidated financial statements for the year ended August 31, 2004 include the Company and its three wholly owned subsidiaries, which were formed in 2004. All significant inter-company transactions have been eliminated upon consolidation. Cash Equivalents - For purposes of reporting cash flows, the Company considers as cash equivalents all highly liquid investments with a maturity of three months or less at the time of purchase. On occasion, the Company has cash in banks in excess of federally insured amounts. See "Concentration of Credit Risks" below. Receivables and Credit Policies - The Company has certain trade receivables consisting of oil and gas sales obligations due under normal trade terms. Management regularly reviews trade receivables and reduces the carrying amount by a valuation allowance that reflects management's best estimate of the amount that may not be collectible. Other Receivables - During fiscal 2004, an unaffiliated third party exercised an option to drill. As a result of this exercise, the Company recorded a $750,000 receivable for this option. This was collected subsequent to year end. Property And Equipment - Furniture and equipment is recorded at cost. Depreciation and amortization of assets is provided by use of the straight-line method over the estimated useful lives of the related assets of three to five years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to operations as incurred. Long-lived assets, other than oil and gas properties, are evaluated for impairment to determine if current circumstances and market conditions indicate the carrying amount may not be recoverable. The Company has not recognized any impairment losses on non-oil and gas long-lived assets. Oil And Gas Properties - The Company utilizes the full cost method of accounting for oil and gas activities. Under this method, subject to a limitation based on estimated value, all costs associated with property acquisition, exploration and development, including costs of unsuccessful exploration, are capitalized within a cost center. The Company's oil and gas properties are located within the United States and Canada. Properties within these respective countries constitute separate cost centers. No gain or loss is recognized upon the sale or abandonment of undeveloped or producing oil and gas properties unless the sale represents a significant portion of oil and gas properties and the gain significantly alters the relationship between capitalized costs and proved oil and gas reserves of the cost center. Depreciation, depletion and amortization of oil and gas properties is computed on the units of production method based on proved reserves. Amortizable costs include estimates of future development costs of proved undeveloped reserves. Capitalized costs of oil and gas properties may not exceed an amount equal to the present value, discounted at 10%, of the estimated future net cash flows from proved oil and gas reserves plus the cost, or estimated fair market value, if lower, of unproved properties. Should capitalized costs exceed this ceiling, an impairment is recognized. The present value of F-9 estimated future net cash flows is computed by applying year end prices of oil and natural gas to estimated future production of proved oil and gas reserves as of year end, less estimated future expenditures to be incurred in developing and producing the proved reserves and assuming continuation of existing economic conditions. A reserve is provided for estimated future costs of site restoration, dismantlement and abandonment activities (see Note 4). The Company utilizes the full cost accounting method of accounting for oil and gas activities and has separate cost centers for the United States and Canada. See Note 9 for additional discussion. The Company leases non-producing acreage for its exploration and development activities. The cost of these leases is included in unevaluated oil and gas property costs recorded at the lower of cost or fair market value. During 2004, the Company acquired the rights to certain proven oil and gas drilling technology for unlimited use on specified areas of interest. The cost of these rights are being included as part of the Company's full cost pools. Revenue Recognition - The Company recognizes oil and gas revenues from its interests in producing wells as oil and gas is produced and sold from these wells. The Company has no gas balancing arrangements in place. Oil and gas sold is not significantly different from the Company's product entitlement. Income Taxes - The Company has adopted the provisions of SFAS 109, Accounting for Income Taxes. SFAS 109 requires recognition of deferred tax liabilities and assets for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. Temporary differences between the time of reporting certain items for financial and tax reporting purposes consist primarily of exploration and development costs on oil and gas properties, and impairment pursuant to the ceiling test limitation. Use Of Estimates - The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The Company's financial statements are based on a number of significant estimates, including reliability of receivables, selection of the useful lives for property and equipment, timing and costs associated with its retirement obligations and oil and gas reserve quantities which are the basis for the calculation of depreciation, depletion and impairment of oil and gas properties. The oil and gas industry is subject, by its nature, to environmental hazards and clean-up costs. At this time, management knows of no substantial costs from environmental accidents or events for which it may be currently liable. In addition, the Company's oil and gas business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. By definition, proved reserves are based on current oil and gas prices and estimated reserves, which is considered a significant estimate by the Company, which is subject to changes. Price declines reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves) and may impact the impairment analysis of the Company's full cost pool. (Loss) Per Share - (Loss) per common share is computed based on the weighted average number of common shares outstanding during each period. Convertible equity instruments, such as convertible notes payable, stock options and warrants, are not considered in the calculation of net loss per share as their inclusion would be anti-dilutive. Share Based Compensation - In October 1995, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation (SFAS 123), effective for fiscal years beginning after December 15, 1995. This statement defines a fair value method of accounting for employee stock options and encourages entities to adopt that method of accounting for its stock compensation plans. SFAS 123 allows an entity to continue to measure compensation costs F-10 for these plans using the intrinsic value based method of accounting as prescribed in Accounting Pronouncement Bulletin Opinion No. 25, Accounting for Stock Issued to Employees (APB 25). The

Company has elected to continue to account for its employee stock compensation plans as prescribed under APB 25. Had compensation cost for the Company's stock-based compensation plans been determined based on the fair value at the grant dates for awards under those plans consistent with the method prescribed in SFAS 123, the Company's net (loss) and (loss) per share for the years ended August 31, 2004 and 2003 would have been increased to the pro forma amounts indicated below: 2004 2003 ----------- ----------- Net (loss): As reported $(1,359,354) $(5,237,613) Pro forma equity compensation expense (1,049,540) (711,165) ----------- ----------- Pro forma net loss $(2,408,894) $(5,948,778) =========== =========== Net pro forma loss per share: As reported $ (0.05) $ (0.22) =========== =========== Pro forma $ (0.09) $ (0.25) =========== =========== See Note 7 with respect to assumptions used. Gas Balancing - The Company uses the sales method of accounting for gas balancing of gas production, and would recognize a liability if the existing proven reserves were not adequate to cover the current imbalance situation. As of August 31, 2004, the Company's gas production is in balance. Fair Value - The carrying amount reported in the balance sheet for cash, prepaid expenses, accounts payable and accrued liabilities approximates fair value because of the immediate or short-term maturity of these financial instruments. In May 2002, the Company completed the sale of $6,000,000, 4.99% convertible promissory notes, due May 2009. The notes are convertible, together with accrued interest, into shares of the Company's common stock at the rate of $1.30 per share, at the option of the holder. The company considers the notes to be stated at fair value due to arms length negotiation of the transaction and the conversion feature. Concentration Of Risk - Financial instruments which potentially subject the Company to concentrations of credit risk consist of cash and receivables. The Company maintains cash accounts at one financial institution. The Company periodically evaluates the credit worthiness of financial institutions, and maintains cash accounts only in large high quality financial institutions, thereby minimizing exposure for deposits in excess of federally insured amounts. The Company believes that credit risk associated cash is remote. The Company has concentrated its United States exploration and production activities primarily in the Rocky Mountain, Texas and Gulf Coast regions. Efforts in Canada are focused on southeast Alberta. All significant activities in these segments have been with industry partners. As of August 31, 2004, there were no reserves associated with the Canadian cost center. The Company's oil and gas prospects in Canada consist of undeveloped properties of approximately $557,000, and there were neither revenues nor expenses recognized in conjunction with this cost center. The Company is pursing the exploration of its Canadian prospects, and management believes that the carrying cost of these prospects is recoverable. Should the Company be unsuccessful in its Canadian exploration activities, the carrying cost of these prospects will be charged to operations. F-11 Customers accounting for 10 percent or more of gross revenue, all representing purchasers of oil and gas, for the years ended August 31, 2004 and 2003 are as follows: 2004 2003 --------------- A 22% 100% B 20% - C 16% - D 13% - Fourth Quarter Adjustment - During the fourth quarter, the Company discovered that certain issuance of common stock and warrants for acquisition of properties and rights to oil and gas technology had inadvertently not been recorded. Therefore, in the fourth quarter, the Company increased stockholders' equity and oil and gas properties by approximately $372,000. The impact on net loss and net loss per share of this oversight was negligible. Reclassification - Certain reclassifications have been made to the 2003 financial statements to conform to 2004 presentation. Such reclassifications had no effect on net loss. Recent Accounting Pronouncements - In June 2001, the FASB issued SFAS No. 141, "Business Combinations" ("SFAS No. 141") and SFAS No. 142, "Goodwill and Intangible Assets" ("SFAS No. 142"). SFAS Nos. 141 and 142 became effective on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. One interpretation that was considered relative to these standards was that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on the Company's consolidated balance sheets. In April 2004, the Financial Accounting Standards Board amended SFAS Nos. 141 and 142 and clarified the interpretation by defining mineral rights, such as oil and gas mineral rights, as tangible assets. Accordingly, the guidelines for accounting for intangible assets as provided in SFAS No. 142 would not apply to oil and gas mineral rights. In accordance with this new guideline, the Company will continue to classify its contractual rights to extract oil and gas reserves as tangible oil and gas properties. 2. ACQUISITION OF PROPERTIES: ------------------------- In 2004, the Company acquired certain oil and gas properties from Venus Exploration for cash consideration of $3,230,000. The purchase also provides for the Company to pay a net profits interest payable to the Venus Exploration Trust ("Trust"). The net profits interest, which applies only to the exploration and exploitation projects on the Venus acreage being acquired, varies from 25% to 50% with respect to different Venus exploration and exploitation project areas, and decreases by one-half of its original amount after a total of $3,300,000 in net profits proceeds has been paid to the Trust. Venus was in Chapter 11 Bankruptcy, and the properties were acquired through public auction as approved by the United States Bankruptcy Court. This acquisition was considered a purchase transaction and the properties acquired were recorded based on the consideration paid as of the closing date of May 8, 2004. Therefore, the statement of operations includes the revenues and operating expenses of the Venus properties for the period from May 2004 to August 2004. F-12 Below is certain unaudited pro forma information based on historical financial information assuming the acquisition had occurred as of the beginning of fiscal 2004 and 2003: 2004 2003 ----------- ----------- Revenues $ 1,847,000 $ 1,977,000 Net loss before cumulative effect of accounting change $(1,055,000) $(4,411,000) Net loss $(1,055,000) $(4,752,000) Net loss per share $ (.04) $ (.17) The above, however, is not necessarily indicative of results which would have occurred if the transaction had closed as of the earlier date nor of future results of operations. To finance the purchase and to provide additional working capital, the Company issued shares of its common stock as described in Note 7. 3. PROPERTY AND EQUIPMENT: ---------------------- Oil and Gas Properties - Oil and gas properties at August 31, 2004 and 2003 consisted of the following: 2004 2003 ------------ ------------ Oil and gas properties, full cost method Unevaluated costs, not subject to amortization $ 5,494,323 $ 5,011,121 Evaluated costs 32,739,846 29,411,814 ------------ ------------ 38,234,169 34,422,935 Less accumulated depreciation, depletion, amortization and impairment (29,382,818) (29,135,097) ------------ ------------ $ 8,851,351 $ 5,287,838 ============ ============ Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property. Exploration costs include the costs of geological and geophysical activity, and drilling and equipping exploratory wells. The Company reviews and determines the cost basis of drilling prospects on a drilling location basis. For the year ended August 31, 2004, the Company did not recognize any impairment expense against the capitalized oil and gas properties in the United States., as determined by the ceiling test performed pursuant to Regulation S-X Rule 4-10(c)(2). Additionally, for the year ended August 31, 2004, the Company did not recognize any impairment expense against the capitalized oil and gas properties in Canada, based upon management's determination that no impairment of undeveloped properties had occurred. For the year ended August 31, 2003, the Company recognized impairment expense of $451,285 for the East Lost Hills project and $2,782,744 for the Company's undeveloped properties. Depreciation, depletion, and amortization of oil and gas properties for the years ended August 31, 2004 and 2003 was $159,848 and $151,284, or $6.65 and $20.50 per barrel of oil equivalent production, respectively. Depreciation of assets recognized in accordance with the Asset Retirement Obligation calculation is included in these amounts (see below). Information relating to the Company's costs incurred in its oil and gas operations during the years ended August 31, 2004 and 2003 is summarized as follows: F-13 2004 2003 ---------- ---------- Property acquisition costs $4,646,880 $ 867,276 Exploration costs 466,529 139,117 Development costs 126,684 467,644 ---------- ---------- $5,240,093 $1,474,037 ========== ========== Furniture and Equipment - Furniture and equipment at August 31, 2004 and 2003 consisted of the following: 2004 2003 --------- --------- Furniture and equipment $ 138,699 $ 128,165 Less accumulated depreciation (111,963) (98,852) --------- --------- $ 26,736 $ 29,313 ========= ========= Depreciation expense associated with capitalized office furniture and equipment during fiscal 2004 and 2003 was $13,111 and $11,191 respectively. 4. ASSET RETIREMENT OBLIGATIONS: ---------------------------- In 2001, the FASB issued SFAS 143, Accounting for Asset Retirement Obligations. SFAS 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires companies to record the present value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The liability is capitalized as part of the related long-lived asset's carrying amount. Over time, accretion of the liability is recognized as an operating expense and the capitalized cost is depreciated over the expected useful life of the related asset. The Company's asset retirement obligations relate primarily to the plugging, dismantlement, removal, site reclamation and similar activities of its oil and gas properties. Prior to adoption of this statement, such obligations were accrued ratably over the productive lives of the assets through depreciation, depletion and amortization of oil and gas properties without recording a separate liability for such amounts. The transition adjustment related to adopting SFAS 143 on September 1, 2002 was recognized as a cumulative effect of a change in accounting principle for the year ended August 31, 2003.

The cumulative effect on net loss of adopting SFAS No. 143 for the year ended August 31, 2003 was a net unfavorable effect of $341,175. At the time of adoption, total net assets increased $428,000, and total liabilities increased $769,175. The amounts recognized upon adoption are based upon numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and gas, future inflation rates and the credit-adjusted risk-free interest rate. F-14 The following table summarizes activity related to the accounting for asset retirement obligations for the fiscal years ended August 31, 2004 and August 31, 2003: 2004 2003 ----------- ----------- Asset retirement obligations, beginning of fiscal year $ 846,093 $ 769,175 Liabilities incurred 211,875 -- Liabilities settled -- -- Accretion of asset retirement obligation including revision of estimates 99,684 76,918 ----------- ----------- Asset retirement obligations, end of fiscal year 1,157,652 846,093 Less current portion (868,163) (727,231) ----------- ----------- Long-term portion $ 289,489 $ 118,862 =========== =========== 5. CONVERTIBLE NOTES PAYABLE: ------------------------- In May 2002, the Company completed the sale of $6,000,000, 4.99% convertible promissory notes, due May 2009. The notes are convertible, together with accrued interest, into shares of the Company's common stock at the rate of $1.30 per share, at the option of the holder. No beneficial interest has been accrued to the notes, as the conversion price approximates the fair market value of the common shares as of the transaction date. Interest is payable semiannually in May and November. At the option of the Company, accrued interest can be paid in cash or added to the principal amount of the notes. At November 24, 2003 and May 24, 2004 the Company elected to add accrued interest of $158,677 and $160,799, respectively, to the balance of the notes. As of August 31, 2004 the balance of the notes is $6,623,351. 6. INCOME TAXES: ------------- The Company follows the asset and liability method of accounting for deferred income taxes. Deferred tax assets and liabilities are determined based on the temporary differences between the financial statement and tax basis of assets and liabilities. At August 31, 2004, the Company had approximately $31,000,000 of net operating losses and $60,000 of statutory depletion carry forward for tax return purposes. The income tax expense recorded in the consolidated statements of operations consists of the following: Years Ended August 31, ------------------------- 2004 2003 ----------- ------------ Current $ -- $ -- Deferred -- -- ----------- ------------ $ -- $ -- =========== ============ The effective income tax rate differs from the U.S. Federal statutory income tax rate due to the following: Years Ended August 31, --------------------- 2004 2003 -------- -------- Federal statutory income tax rate (34%) (34%) Increase in valuation allowance 34% 34% -------- -------- Effective rate - - ======== ======== F-15 The principal sources of temporary differences resulting in deferred tax assets and tax liabilities at August 31, 2004 are as follows: 2004 ------------ Deferred tax assets: Property impaired for financial reporting, but capitalized for tax; offset by intangible drilling and other exploration costs capitalized for financial reporting purposes but deducted for tax purposes $ 2,500,000 Asset retirement obligation 400,000 Tax loss carryforward 11,400,000 ------------ Total deferred tax assets 14,300,000 Deferred tax liabilities -- ------------ Net deferred tax asset 14,300,000 Valuation allowance (14,300,000) ------------ Net deferred taxes $ -- ============ The valuation allowance increased by approximately $500,000 and $1,900,000 in 2004 and 2003, respectively. 7. STOCKHOLDERS' EQUITY: -------------------- Preferred Stock -In April 1999, the stockholders of the Company approved an amendment to the Certificate of Incorporation pursuant to which the company was authorized to issue 1,000,000 shares of preferred stock, with a par value of $.001 per share. Such shares of preferred stock may be issued with such preferences and rights as determined by the Board of Directors. Common Stock - During the year ended August 31, 2004, the Company completed the sale of 7,500,000 shares of common stock pursuant to a private placement at a price of $1.09 per share. The first tranche of the Placement, consisting of 4.5 million shares and $4,905,000 in gross proceeds, was received and accepted in early May 2004. The second tranche of the Placement, consisting of 3.0 million shares and $3,270,000 in gross proceeds, was received and accepted in late June 2004. Costs of the offering were $1,092,803, which included warrants valued at $352,500. During the year ended August 31, 2004, the Company issued 125,000 shares of common stock for an interest in oil and gas properties, valued as of the date of the transaction at $90,000 ($.72 per share). The Company also issued 186,403 shares of common stock for an interest in rights to oil and gas technology, valued as of the date of the transaction at $247,916 ($1.33 per share). Warrants - During the year ended August 31, 2004, the Company issued a warrant to purchase 100,000 shares of common stock at an exercise price of $.65 per share through December 1, 2006, for rights to oil and gas technology. The warrants are valued at $34,000, based on the Black-Scholes option pricing model, and this amount was included in oil and gas properties for the year ended August 31, 2004. During fiscal 2004, the Company also issued warrants in partial payment of a commission for financial advisory services performed in connection with the private placement of common stock in May and June, 2004. Included in this issuance was (i) a warrant to purchase

225,000 shares of common stock at an exercise price of $1.30 per share and (ii) a warrant to purchase 150,000 shares of common stock at an exercise price of $1.24 per share. These warrants expire on May 5, 2009 and June 11, 2009, respectively. The warrants are valued at $229,500 and $123,000, respectively, based on the Black-Scholes option pricing model, and these amounts were included as costs associated with the private placement in additional paid-in capital for the year ended August 31, 2004. F-16 At August 31, 2004, the status of outstanding warrants is as follows: Issue Shares Exercise Expiration Date Exercisable Price Date ---------------- ----------- -------- ---------------- May 9, 2002 200,000 $1.49 May 8, 2007 December 1, 2003 100,000 $0.65 December 1, 2006 May 5, 2004 225,000 $1.30 May 5, 2009 June 11, 2004 150,000 $1.24 June 11, 2009 At August 31, 2004, the weighted average remaining contractual life of outstanding warrants was 3.6 years. Stock Options - Under two stock option plans, options to purchase common stock may be granted until 2010. Stock options are granted to employees at exercise prices equal to the fair market value of the Company's stock at the dates of grants. Generally, options vest 1/3 each year for a period of three years from grant date and can have a maximum term of up to 10 years. Options are issued to key employees and other persons who contribute to the success of the Company. The Company has reserved 3,250,000 shares of common stock for these plans. At August 31, 2004 and 2003, options to purchase 731,000 and 0 shares, respectively, were available to be granted pursuant to the stock option plans. The status of outstanding options granted pursuant to the plans are as follows: Number of Weighted Avg. Weighted Avg. Shares Exercise Price Fair Value --------- ------------- ------------- Options Outstanding - September 1, 2002 (858,165 exercisable) 1,391,500 $ 3.03 Granted 940,000 $ .70 $ .22 Exercised - - Expired (115,000) $ 2.41 --------- Options Outstanding - August 31, 2003 (1,031,498 exercisable) 2,216,500 $ 2.07 Granted 843,000 $ .95 $ .61 Exercised (51,666) $ .29 Expired (824,000) $ 1.87 --------- Options Outstanding - August 31, 2004 (1,076,168 exercisable) 2,183,384 $ 1.76 ========= The calculated value of stock options granted under these plans, following calculation methods prescribed by SFAS 123, uses the Black-Scholes stock option pricing model with the following assumptions used: 2004 2003 ---------- -------- Expected option life-years 3-5 7 Risk-free interest rate 3.1 - 3.9% 3.0 % Dividend yield 0 0 Volatility 62 - 125% 107% F-17 At August 31, 2004 and 2003, the number of options exercisable was 1,076,168 and 1,031,498, respectively, and the weighted average exercise price of these options was $1.64 and $2.99, respectively. Options Outstanding ----------------------------- Remaining Options August 31, Contractual Life Exercisable at Exercise Price 2004 (years) August 31, 2004 -------------- --------- ---------------- --------------- $0.29 377,884 6 91,668 $0.49 - $0.92 490,000 4-5 190,000 $1.09 - $1.30 630,500 4 154,500 $1.65 - $1.82 240,000 3 195,000 $4.00 235,000 1 235,000 $5.43 - $5.98 210,000 1 210,000 --------- ----------- Total 2,183,384 1,076,168 ========= =========== 8. COMMITMENTS AND CONTINGENCIES: ----------------------------- Office Leases - The Company currently leases space in Denver, Colorado and San Antonio, Texas. Total minimum rental payments for non-cancelable operating leases are as follows; 2005 $ 98,521 2006 70,123 2007 70,023 2008 23,237 ---------- $ 261,904 ========== Rent expense was approximately $114,000 and $100,000 for the years ended August 31, 2004 and 2003, respectively. In September 2004, the Company renegotiated its Denver office lease, which is reflected in the table above. Delay Rentals - In conjunction with the Company's working interests in undeveloped oil and gas prospects, the Company must pay approximately $490,000 in delay rentals and other costs during the fiscal year ending August 31, 2005 to maintain the right to explore these prospects. The Company continually evaluates its leasehold interests, therefore certain leases may be abandoned by the Company in the normal course of business. Environmental - Oil and gas producing activities are subject to extensive Federal, state and local environmental laws and regulations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the costs can be reasonably estimated. Contingencies - The Company may from time to time be involved in various claims, lawsuits, disputes with third parties, actions involving allegations of discrimination, or breach of contract incidental to the operations of its business. The Company is not currently involved in any such incidental litigation which it believes could have a materially adverse effect on its financial condition or results of operations. F-18 9. UNAUDITED OIL AND GAS RESERVE INFORMATION: -- At August 31, 2004, the estimated oil and gas reserves presented herein were derived from a report prepared by Ryder Scott Company, an independent petroleum engineering firm. All reserves are located within the continental United

States. The Company had no oil and gas reserves at August 31, 2003. The Company cautions that there are many inherent uncertainties in estimating proved reserve quantities and in projecting future production rates and the timing of development expenditures. Accordingly, these estimates are likely to change as future information becomes available, and these changes could be material. The oil and gas reserve estimates presented below include all activity from the Company's oil and gas properties for 2004. Proved reserves at the end of the year are from the Company's Venus properties only. The Company had no proved reserves as of August 31, 2003. The Company realized production from its East Lost Hills prospect in 2003 and 2004, but has not recorded any proved reserves as it had been previously determined that reserves from this prospect were not economic to produce. Revisions of previous estimates for 2004 is solely the result of the current year production from the East Lost Hills prospect, and these amounts are also included in production for 2004. Proved oil and gas reserves are the estimated quantities of crude oil, condensate, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves expected to be recovered through existing wells with existing equipment and operating methods. Analysis Of Changes In Proved Reserves - Estimated quantities of proved developed and undeveloped reserves, as well as the changes during the year ended August 31, 2004, are as follows: Oil and Natural Gas Natural Liquids Gas (Bbls) (Mcf) ---------- ---------- Proved reserves at August 31, 2003 -- -- Purchase of reserves 629,573 1,064,205 Revisions of previous estimates 12,044 20,362 Extensions and discoveries 57,219 370,927 Sales of reserves in place -- -- Improved recovery -- -- Production (13,971) (62,494) ---------- ---------- Proved reserves at August 31, 2004 684,865 1,393,000 ========== ========== Proved developed reserves - end of year 559,629 842,000 ========== ========== The table below sets forth a standardized measure of the estimated discounted future net cash flows attributable to the Company's proved oil and gas reserves. Estimated future cash inflows were computed by applying year end (August 31) prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) averaging $40.97/bbl and $4.49/mcf to the estimated future production of proved oil and gas reserves at August 31, 2004. The future production and development costs represent the estimated future expenditures to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future corporate overhead expenses and interest expense have not been included. Discounting the annual net cash flows at 10% illustrates the impact of timing on these future cash flows. F-19 Standardized Measure of Estimated Discounted Future Net Cash Flows -- 2004 ------------ Future cash inflows $ 34,192,000 Future cash outflows: Production cost (13,519,000) Development cost (2,426,000) ------------ Future net cash , before income taxes 18,247,000 Future income taxes -- ------------ Future net cash flows 18,247,000 Adjustment to discount future annual net cash flows at 10% (7,203,000) ------------ Standardized measure of discounted future net cash flows $ 11,044,000 ============ The following table summarizes the principal factors comprising the changes in the standardized measure of estimated discounted net cash flows for the year ended August 31, 2004. Changes in Standardized Measure of Estimated Discounted Net Cash Flows -- 2004 ------------ Standardized measure, beginning of period $ -- Purchase of reserves 6,942,000 Sales of oil and gas, net of production cost (528,000) Net change in sales prices, net of production cost 2,725,000 Discoveries, extensions and improved recoveries, net of future development cost 1,464,000 Development costs incurred -- Change in future development costs (692,000) Sales of reserves in place -- Revisions of quantity estimates 314,000 Accretion of discount -- Other 819,000 ------------ Standardized measure, end of period $ 11,044,000 ============ F-20