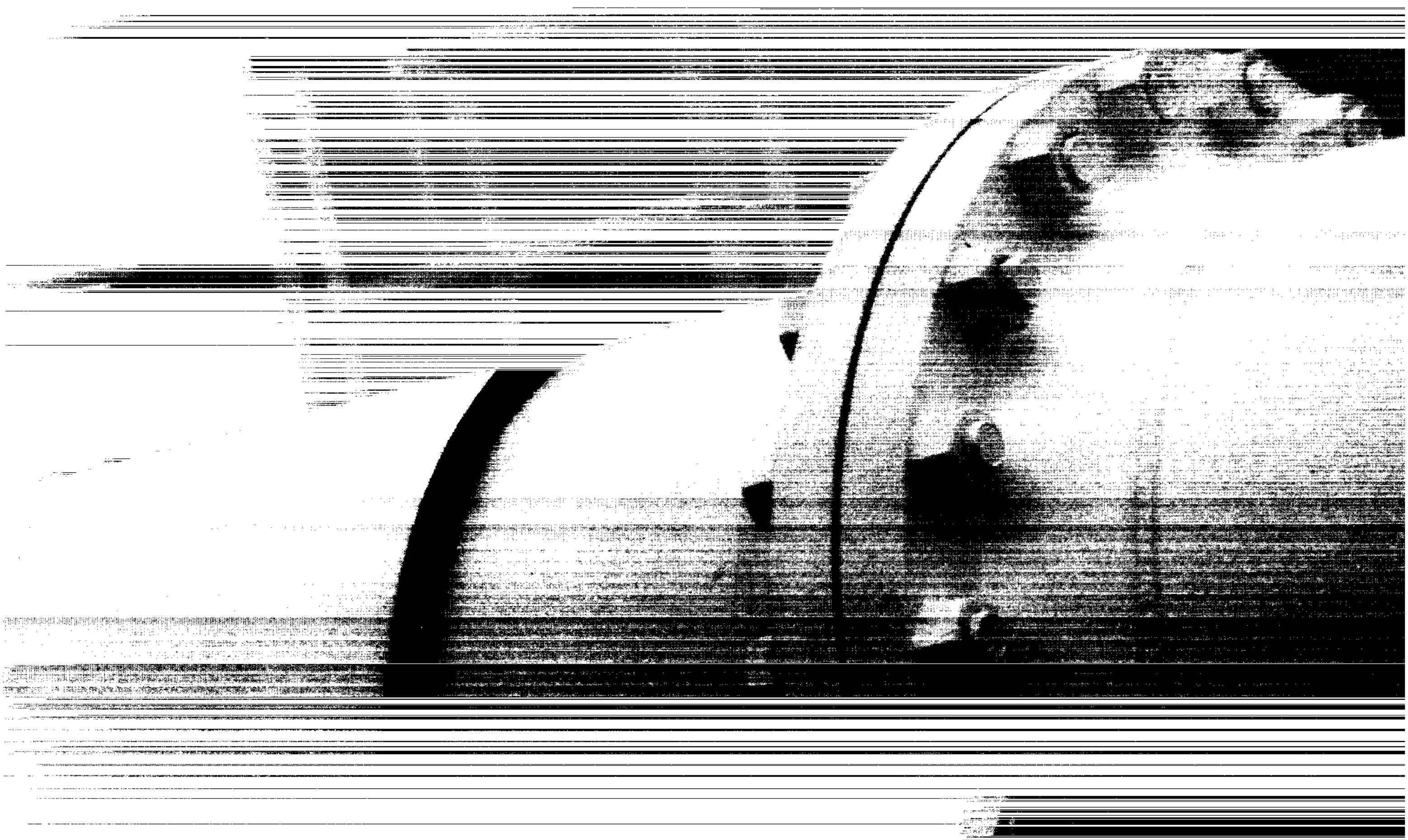
PLAINS RESOURCES

Annual Report 2002

CORPORATE PROFILE

Plains Resources Inc. (NYSE:PLX), headquartered in Houston, Texas, is a unique energy company actively involved in the midstream and upstream sectors of the energy industry. PLX is engaged principally in the midstream activities of marketing, gathering, transporting, terminaling, and storage of crude oil through its significant equity ownership in Plains All American Pipeline, L.P. (NYSE:PAA). PAA is a publicly traded master limited partnership actively engaged in the midstream energy markets. Currently, PLX owns 44% of the general partner of PAA and 12.4MM limited partnership units of PAA, which currently represents approximately 24% aggregate ownership interest in PAA. PLX also participates in the production of oil in Florida through its wholly-owned subsidiary, Calumet Florida L.L.C.

Plains Resources has been in existence for 25 years and its management team has over 100 years of combined experience in the energy sector. The Company is led by Chairman of the Board Jim Flores and Chief Executive Officer and President John Raymond. We believe Plains Resources is well-positioned with its midstream and upstream platforms to capitalize on future energy opportunities given its strong liquidity position and free cash flow.



TO OUR FELLOW SHAREHOLDERS:

In 2002, your company delivered a solid operational and financial performance against the backdrop of uncertain times on many fronts. Additionally, through the course of the year several strategic initiatives were successfully executed that culminated in the December 18, 2002 separation of Plains Exploration & Production Company (PXP) from Plains Resources Inc. (PLX) via a tax free share for share distribution of PXP shares. Henceforth, at the end of 2002, PLX no longer owned the vast majority of the upstream assets that it owned for the first 351 days of the year. The accomplishments of 2002 set the stage for the future of both companies as the two distinct platforms allow each company to pursue objectives in different segments of the energy business that have equally distinct characteristics without giving effect to each other.

From a strategic perspective, the separation transformed PLX into a company that generates relatively substantial amounts of cash flow when measured against the minimal cash requirements needed to run the business. Additionally, the vast majority of the inflows are generated by the Company's continuing interests in Plains All American Pipeline, L.P. (PAA) which employs, through its Master Limited Partnership status, a business strategy in the highly secular midstream segment of the energy business that manifests a ratable, predictable cash flow profile. In order to satisfy the five year active business test for IRS purposes related to the PXP spin off, PLX also retained the upstream operations in Florida. We manage these operations in an effort to provide for as stable a cash flow profile as practicable. While more volatile than the midstream interests, the income from these assets is relatively small when viewed in the context of the total.

The challenge for management encompasses several dimensions. As mentioned above, given PLX's ownership structure in PAA, significant cash flow is generated with minimal cash requirements resulting in a durable free cash flow stream at PLX that grows over time as PAA grows. This growth requires very modest cash outlays at the PLX level which manifests exceptional rates of return in both an absolute and per share sense. The resulting discussion revolves around the most prudent use of the cash flow when ranked against a capital allocation hierarchy. While we scour the landscape for compelling opportunities, historically we have found that PLX represents our best opportunity. We therefore continue to invest in ourselves via an active share repurchase program thereby increasing per share leverage to absolute performance. Consistent with our long-term objective, this also represents the most tax efficient manner to return dollars to our shareholders. Given what we know today, we would expect the treasury share program to be enduring for years to come and henceforth very meaningful when viewed in the context of the current share base.

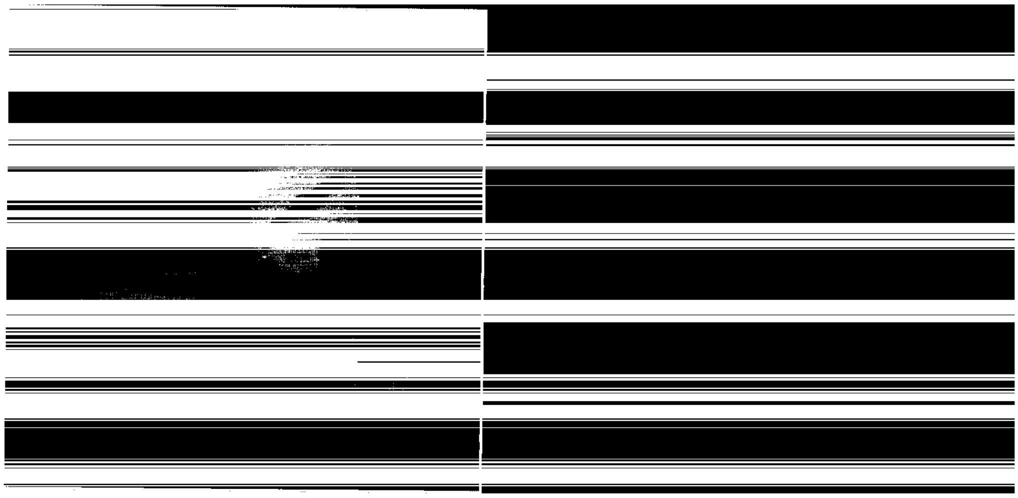
Beyond the capital allocation discussion associated with the ever changing external opportunity set, the company has several other key internal initiatives under evaluation to further enhance value. The company has the benefit of a substantial tax asset that defers a portion of current taxes for several years. The optimization of this asset coupled with alternative tax strategies for future years will be a focus issue in an attempt to minimize tax friction as we move forward in time. Additionally, the company is progressing on discussions to explore other potential projects in the gas storage arena utilizing some of our existing assets in Florida. These projects could be large in scale with several years of lead time required between inception and the actual recognition of cash flow. Such projects must be structured accordingly to provide for a balance between the needs of the corporation and the maximization of project specific economics. As with most organizations, there will always be more to do and we as a management team look forward to these challenges within the confines of a self-imposed strict focus and discipline on overhead.

While we by no means of the word belittle accounting conventions and the associated methodologies for closing the books, at the risk of reducing this to a technical accounting discussion, there are two accounting dynamics that are of paramount importance to understanding the value of your company over time. First, as a result of the spin-off our historical financials will include a discontinued operations line item that reflects the operations and associated financials of the "spun" assets, namely PXP. To that end, while the company reported $37.5 million of net income for the year, net income from continuing operations was $9.7 million. Of course, our interests in PAA are accounted for under the equity method of accounting and reflect only our proportionate share of PAA's net income as opposed to the cash distributions. To put this in perspective, in 2002 we recognized $18.8 million of equity income and received $29.1 million of cash distributions. Non-cash items can effect the income statement of the partnership and in turn the equity income we recognize from PAA yet have no effect on cash distributions. Secondly, at year end the company carried $70 million of book value for its interest in PAA on the balance sheet. This is clearly an extremely conservative booking given that the current market value greatly exceeds the carrying value. Over time as distributions exceed income at PAA, our carrying value will be reduced. If and when there are further equity issuances at PAA, our carrying value increases per GAAP accounting principles. However, with all else being equal, the actual fair value of the units stays virtually constant notwithstanding the gyrations in the carrying value per accounting conventions. The result is a year end long-term debt to book capitalization of 21% with the denominator being a function of the low carrying value of our PAA interests. Stated differently, to the extent we monetized our interest, we would book a significant gain that would increase the equity account and thereby reduce the gearing to substantially lower levels. Of course the numerator will continue to work in our favor as well given the amortizing feature in the debt facility.

From an operational perspective, produced volumes in Florida once again surpassed expectations at 970,000 barrels. This trend has continued into the first quarter and, barring any unfortunate occurrences, we expect Florida to generate another very solid year in 2003 as outlined in the guidance we have publicly provided. Field optimization coupled with improved run times are the catalysts behind the steady performance of this business unit. The credit for this clearly lies with the operations personnel who have done an excellent job of constantly seeking a better, more efficient means to accomplish the desired ends. It is the hard work and dedication of all of our employees that once again produces the solid results outlined in this report. Finally, we would be remiss not to recognize the loyal support of all of our shareholders, partners and customers. While the uncertainties of the current business climate can often times test these loyalties, we are deeply grateful for your enduring support.

We optimistically look to the future and believe that your company is well positioned to again deliver solid results in 2003 and beyond.

John T. Raymond
Chief Executive Officer and President



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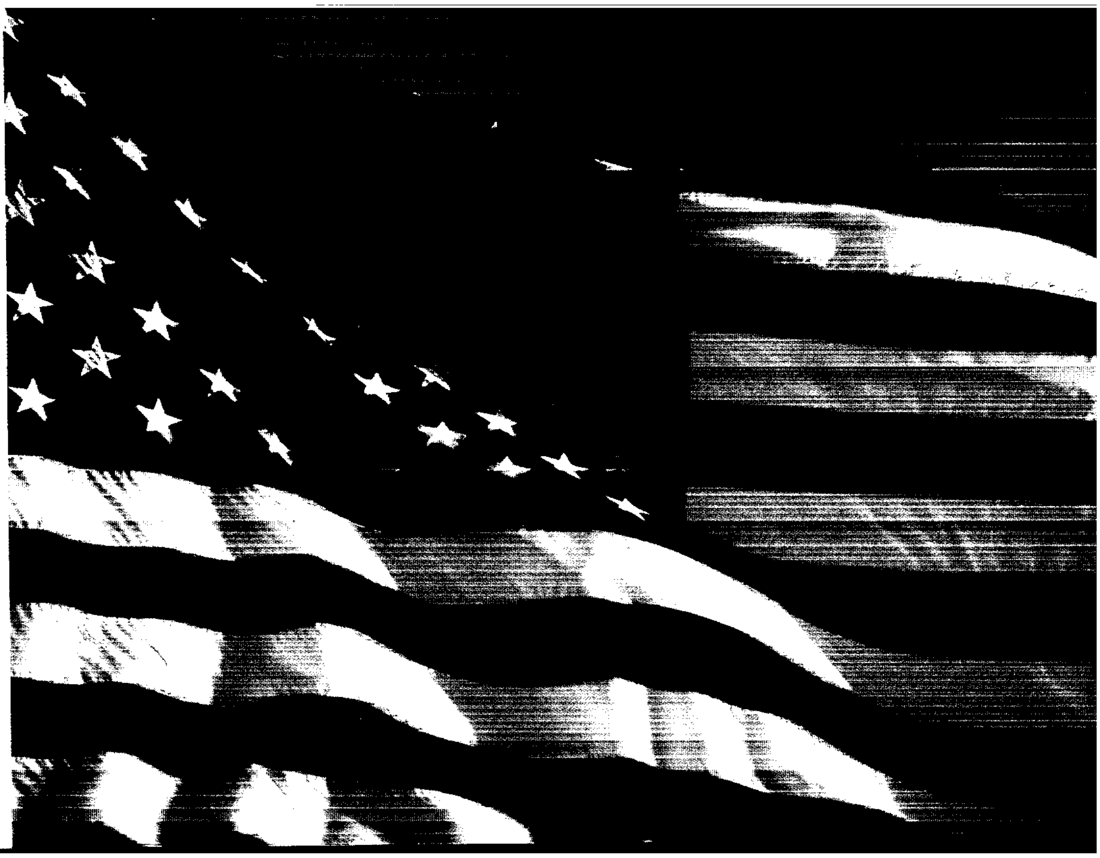

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

FOR ANNUAL AND TRANSITION REPORTS PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2002

or

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

Commission file number 0-9808

Plains Resources Inc.
(Exact name of registrant as specified in its charter)

Delaware	**13-2898764**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

500 Dallas Street, Suite 700
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)

(713) 739-6700
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☑ No ☐

On February 28, 2003, there were 24,167,935 shares of the registrant's Common Stock outstanding. The aggregate market value of the Common Stock held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $592,221,000 on June 28, 2002 (based on $26.75 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date). On December 18, 2002 we completed the spin-off of Plains Exploration & Production Company ("PXP"). At the close of business on such date, our closing price per share as reported on the NYSE (on a "with dividend" basis) was $23.05. The closing price per share of PXP on such date as reported on the NYSE (on a "when issued" basis) was $9.10. Our closing price on December 19, 2002 and February 28, 2003, as reported on the NYSE, was $12.51 and $11.39, respectively. The aggregate market value of the common stock held by non-affiliates of the registrant was approximately $252,165,000 on February 28, 2003 (based on the closing price on that date).

DOCUMENTS INCORPORATED BY REFERENCE: The information required in Part III of the Annual Report on Form 10-K is incorporated by reference to the registrant's definitive proxy statement to be filed pursuant to Regulation 14A for the registrant's 2003 Annual Meeting of Stockholders.

PLAINS RESOURCES INC.

2002 ANNUAL REPORT ON FORM 10-K

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STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements based on our current expectations and projections about future events. Statements that are predictive in nature, that depend upon or refer to future events or conditions, or that include words such as "will", "would", "should", "plans", "likely", "expects", "anticipates", "intends", "believes", "estimates", "thinks", "may", and similar expressions, are forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause our actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. These factors include, among other things:

- the consequences of any potential change in the relationship between us and Plains Exploration & Production Company;
- the consequences of our and Plains Exploration's officers and employees providing services to both us and Plains Exploration and not being required to spend any specified percentage or amount of time on our business;
- risks, uncertainties and other factors that could have an impact on Plains All American Pipeline, L.P., or PAA, which could in turn impact the value of our holdings in PAA (for a discussion of these risks, uncertainties and other factors, see PAA's filings with the SEC);
- the effects of our indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt, and could have other adverse consequences;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations;
- the effects of competition;
- the success of our risk management activities;
- the availability (or lack thereof) of acquisition or combination opportunities;
- the impact of current and future laws and governmental regulations;
- environmental liabilities that are not covered by an effective indemnity or insurance, and
- general economic, market, industry or business conditions.

All forward-looking statements in this report are made as of the date hereof, and you should not place undue certainty on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report. Moreover, although we believe the expectations reflected in the forward-looking statements are based upon reasonable assumptions, we can give no assurance that we will attain these expectations or that any deviations will not be material. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information. See Items 1 & 2. — "Business and Properties — Risk Factors" and Item 7. — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Factors That May Affect Future Results" in this report for additional discussions of risks and uncertainties.

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the SEC's Public Reference Room. Our SEC filings are also available to the public at the SEC's web site at *www.sec.gov*. No information from such web site is incorporated by reference herein. Our web site is *www.plainsresources.com*. You may also obtain copies of our annual, quarterly and current reports, proxy statements and certain other information filed with the SEC, as well as amendments thereto, free of charge from our web site. These documents are posted to our web site as soon as reasonably practicable after we have filed or furnished these documents with the SEC.

GLOSSARY OF OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and this Form 10-K:

API gravity. A system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

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

BOE. One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil volumes based on relative heat content, at a ratio of 6 Mcf to 1 Bbl of oil.

Developed acreage. The number of acres which 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 gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil from an established spot market price to reflect differences in the quality and/or location of oil.

Exploratory well. A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Farm-in. An agreement between a participant who brings a property into the venture and another participant who agrees to spend an agreed amount to explore and develop the property and has no right of reimbursement but may gain a vested interest in the venture. A "farm-in" describes the position of the participant who agrees to spend the agreed-upon sum of money to gain a vested interest in the venture.

Gas. Natural gas.

Gross acres. The total acres in which a person or entity has a working interest.

Gross oil and gas wells. The total wells in which a person or entity owns a working interest.

Infill drilling. A drilling operation in which one or more development wells is drilled within the proven boundaries of a field.

LPG. Liquefied petroleum gas.

MBbl. One thousand barrels of oil or other liquid hydrocarbons.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of gas.

Midstream. The portion of the oil and gas industry focused on marketing, gathering, transporting and storing oil.

MMBbl. One million barrels of oil or other liquid hydrocarbons.

MMBOE. One million BOE.

MMcf. One million cubic feet of gas.

Net acres. Gross acres multiplied by the percentage working interest.

Net oil and gas wells. Gross wells multiplied by the percentage working interest.

Net production. Production that is owned, less royalties and production due others.

Net revenue interest. Our share of petroleum after satisfaction of all royalty and other non-cost-bearing interests.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil, condensate and natural gas liquids.

Operator. The individual or company responsible for the exploration and/or exploitation and/or production of an oil or gas well or lease.

PV-10. The pre-tax present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions).

Proved developed reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Per Article 4-10(a)(2) of Regulation S-X, the SEC defines proved oil and gas reserves as the estimated quantities of oil, gas and 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, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes: (i) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (ii) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved reserves do not include: (i) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (ii) oil, gas, and gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (iii) oil, gas, and gas liquids, that may occur in undrilled prospects; and (iv) oil, gas, and gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

Proved reserve additions. The sum of additions to proved reserves from extensions, discoveries, improved recovery, acquisitions and revisions of previous estimates.

Proved undeveloped reserves. Proved undeveloped oil and gas reserves are 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. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Reserve life. A measure of the productive life of an oil and gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year-end by production for that year.

Reserve replacement cost. The cost per BOE of reserves added during a period calculated by using a fraction, the numerator of which equals the costs incurred for the relevant property acquisition, exploration, exploitation and development and the denominator of which equals changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

Reserve replacement ratio. The proved reserve additions for the period divided by the production for the period.

Royalty. An interest in an oil and 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.

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of price changes to the extent provided by contractual arrangements), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on current costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations.

Undeveloped acreage. Acreage held under lease, permit, contract or option that is not in a spacing unit for a producing well.

Upstream. The portion of the oil and gas industry focused on acquiring, exploiting, developing, exploring for and producing oil and gas.

Waterflood. A secondary recovery operation in which water is injected into the producing formation to maintain reservoir pressure and force oil toward and into the producing wells.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for 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.

References herein to "Plains Resources", "Plains", the "Company", "we", "us" and "our" mean Plains Resources Inc.

PART I

Items 1 and 2. *Business and Properties.*

General

We are an independent energy company. We are principally engaged in the "midstream" activities of marketing, gathering, transporting, terminaling, and storage of oil through our equity ownership in Plains All American Pipeline, L.P., or PAA. PAA is a publicly traded master limited partnership actively engaged in the midstream energy markets. As of March 15, 2003 we owned 44% of the general partner of PAA and 12.4 million, or 24%, of the limited partner units of PAA, which represented approximately 24% aggregate ownership interest in PAA. See "— Plains All American Pipeline, L.P.". We also participate in the "upstream" activities of acquiring, exploiting, developing, exploring for and producing oil through our wholly-owned subsidiary, Calumet Florida L.L.C., which has producing properties in the Sunniland Trend in south Florida.

The book value of our investment in PAA represents 43% of our total assets as of December 31, 2002 and the book value of our Florida oil properties represents 31%. As of December 31, 2002, the present value of our proved oil reserves was approximately $87.9 million (see " — Oil Production Operations"). We own 6.6 million common units, 1.3 million Class B common units and 4.5 million subordinated units of PAA. The closing price of publicly traded PAA common units, as reported on the New York Stock Exchange, was $24.40 on December 31, 2002. The Class B common units and the subordinated units are not publicly traded but do receive cash distributions from PAA. PAA's partnership agreement contains provisions which, upon the occurrence of certain future events, will result in the conversion of the subordinated units to common units. See — "Plains All American Pipeline, L.P. — PAA Cash Distributions". PAA's financial performance directly impacts our financial performance and the market value performance of PAA's limited partner interests directly impacts the value of our assets. As a result, we encourage you to review PAA's SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2002, to review and assess, among other things, PAA's financial performance and financial condition, PAA's business, operations, and competition, and risk factors associated with PAA's business.

We also have an active treasury share repurchase program. Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. Through December 31, 2001, we had repurchased a total of 4.1 million shares at a total cost of approximately $91.3 million. No shares were repurchased in 2002. We have resumed making purchases under the treasury share program and through March 15, 2003 we have repurchased an additional 142,700 shares at a total cost of $1.6 million. We intend to make additional repurchases in 2003 and expect to fund the purchases from cash flows.

Spin-off of Plains Exploration & Production Company

Prior to December 18, 2002 Plains Exploration & Production Company, or PXP, was our wholly owned subsidiary. On December 18, 2002 we distributed the issued and outstanding shares of PXP common stock to the holders of record of our common stock as of the close of business on December 11, 2002. Each of our stockholders received one share of PXP common stock for each share of our common stock held. Prior to the spin-off, we made an aggregate of $52.2 million in cash contributions to PXP and transferred certain assets and liabilities to PXP, primarily related to land, unproved oil and gas properties, office equipment and pension obligations.

In contemplation of the spin-off, under the terms of a Master Separation Agreement between us and PXP, on July 3, 2002 we contributed to PXP 100% of the capital stock of our wholly owned subsidiaries that own oil and gas properties in offshore California and Illinois. As a result, PXP indirectly owned our offshore California and Illinois properties and directly owned our onshore California properties. We also contributed $256.0 million of intercompany receivables that PXP and its subsidiaries owed to us. On July 3, 2002 PXP issued $200 million of 8.75% Senior Subordinated

Notes due 2012, or the 8.75% notes, and entered into a $300 million revolving credit facility. PXP distributed to us the net proceeds of $195.3 million from the 8.75% notes and $116.7 million of initial borrowings under the credit facility. We used such amounts to redeem our 10.25% senior subordinated notes on August 3, 2002 ($287.0 million) and to repay amounts outstanding under our credit facility ($25.0 million).

We received a letter ruling from the IRS on May 22, 2002, as supplemented on November 5, 2002, to the effect that the spin-off will qualify as a tax-free distribution. A letter ruling from the IRS, while generally binding on the IRS, may under certain circumstances be retroactively revoked or modified by the IRS. A letter ruling is based on the facts and representations presented in the request for that ruling. Generally, an IRS letter ruling will not be revoked or modified retroactively if there has been no misstatement or omission of material facts, the facts at the time of the transaction are not materially different from the facts upon which the IRS letter ruling was based, and there has been no change in the applicable law. We are not aware of any facts or circumstances that would cause the representations in the ruling request to be untrue or incomplete in any material respect.

As a result of the spin-off the historical results of the operations of PXP are reflected in our financial statements as "discontinued operations". Except as noted, discussions in this Form 10-K with respect to oil and gas operations relate to our activities other than the discontinued operations of PXP. In connection with the spin-off, we entered into certain agreements with PXP, see "— Spin-off Agreements" and "— Discontinued Operations".

Plains All American Pipeline, L.P.

As of March 15, 2003, our aggregate ownership interest in PAA was approximately 24%, which was comprised of (1) a 44% interest in the general partner of PAA, (2) 45%, or approximately 4.5 million, of the subordinated units and (3) 24%, or approximately 7.9 million, of the common units, including approximately 1.3 million class B common units.

As a result of our June 2001 strategic restructuring (see "— Our June 2001 Strategic Restructuring"), our minority interest in PAA is accounted for using the equity method of accounting effective January 1, 2001. Under this method, we no longer consolidate the assets, liabilities and operating activities of PAA. Rather, our ownership interest in PAA is reflected as an investment in the balance sheet and we record our share of PAA's results of operations.

Operations

PAA is a publicly traded master limited partnership that is engaged in the marketing, transportation and terminalling of oil and the marketing of liquefied petroleum gas. Terminals are facilities where oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling". PAA is the exclusive purchaser/marketer of all of our equity oil production.

PAA's operations are concentrated in Texas, Oklahoma, California and Louisiana and in the Canadian provinces of Alberta and Saskatchewan, and can be categorized into two primary business activities:

- *Oil Pipeline Transportation Operations.* PAA owns and operates over 5,600 miles of gathering and mainline oil pipelines located throughout the United States and Canada. Its activities from pipeline operations generally consist of transporting oil for a fee, third party leases of pipeline capacity, barrel exchanges and buy/sell arrangements.
- *Gathering, Marketing, Terminalling and Storage Operations.* PAA owns and operates approximately 22.7 million barrels of above-ground oil terminalling and storage facilities, including tankage associated with its pipeline systems. These facilities include an oil terminalling and storage facility at Cushing, Oklahoma. Cushing is one of the largest oil market hubs in the United States and the designated delivery point for NYMEX oil futures

contracts. PAA's terminalling and storage operations generate revenue through a combination of storage and throughput charges to third parties. PAA also utilizes its storage tanks to counter-cyclically balance its gathering and marketing operations and to execute different hedging strategies to stabilize profits and reduce the negative impact of oil market volatility. PAA's gathering and marketing operations include:

- the purchase of oil at the wellhead and the bulk purchase of oil at pipeline and terminal facilities;
- the transportation of oil on trucks, barges and pipelines;
- the subsequent resale or exchange of oil at various points along the oil distribution chain; and
- the purchase of LPG from producers, refiners and other marketers, and the sale of LPG to wholesalers, retailers and industrial end users.

PAA Cash Distributions

PAA's partnership agreement requires that it distribute 100% of available cash within 45 days after the end of each quarter to unitholders of record and to its general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of each quarter less reserves established by PAA's general partner for future requirements.

Distributions to holders of subordinated units are subject to the rights of holders of common units to receive the minimum quarterly distribution, or MQD, of $0.45 per unit ($1.80 per unit on an annual basis). Common units accrue arrearages with respect to distributions for any quarter during the subordination period and subordinated units do not accrue any arrearages. The subordination period will end if PAA meets certain financial tests for three consecutive four-quarter periods. If PAA meets certain financial requirements, 25% of the subordinated units will convert in the fourth quarter of 2003 and the remainder will convert in the first quarter of 2004.

Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. If we request that PAA call a meeting of common unitholders to consider approval of the conversion of Class B units into common units and the approval is not obtained within 120 days, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

PAA's general partner is entitled to receive incentive distributions if the amount distributed with respect to any quarter exceeds levels specified in its partnership agreement. Generally the general partner is entitled, without duplication, to 15% of amounts PAA distributes in excess of $0.450 per unit, 25% of the amounts PAA distributes in excess of $0.495 per unit and 50% of amounts PAA distributes in excess of $0.675 per unit.

Based on PAA's current annual distribution rate of $2.15 per unit, we would receive for 2003 an annual distribution from PAA of approximately $30.1 million, including $2.8 million for our general partner distribution (including $1.8 million for the general partner incentive distribution).

Our June 2001 Strategic Restructuring

On June 8, 2001, we sold a portion of our interests in PAA to a group of investors and management of PAA for approximately $155.2 million. The assets we sold in this restructuring included 52%, or approximately 5.2 million, of the subordinated units of PAA, at $22 per unit, and an aggregate 54% ownership interest in the general partner of PAA. We received approximately $110 million in cash and 23,108 shares of our series F preferred stock valued at $45.2 million as consideration for the sale. We recognized a pre-tax gain of $128.3 million in connection with this sale. In connection with our strategic restructuring, the holders of the remaining shares of our series F preferred stock converted their shares into 2.2 million shares of our common stock and received from us a cash payment of approximately $2.5 million, equal to, with respect to each share of our series F preferred stock converted, the accrued dividends on each share from June 8, 2001 until the first date on which we could cause conversion of the shares, plus a 20% premium on the amount of the accrued dividends. Also, in connection with our strategic restructuring, holders of our series H preferred stock converted an aggregate of 132,022 shares into approximately 4.4 million shares of our common stock. We also granted management of PAA an option to acquire an additional 2% ownership interest in the general partner of PAA, which PAA management exercised in September 2001 by paying us $1.5 million in cash and notes. As a result of this exercise we recognized a gain of $1.1 million.

As a result of our strategic restructuring, all of our series F preferred stock and all but approximately 36,000 shares of our series H preferred stock were retired or converted. The remaining outstanding shares of our series H preferred stock were converted into 1.2 million shares of our common stock during the third quarter of 2001.

The excess of the fair value of our Series F preferred stock redeemed as consideration over the carrying value of such series F preferred stock ($21.4 million) was deemed for accounting purposes to be a dividend to our preferred stockholders. As a result, for purposes of determining our basic and diluted earnings per share, we deducted this amount in determining our income available to our common stockholders.

In exchange for the significant value we received for the subordinated units (which are subordinated in right to distributions from PAA and are not publicly traded) relative to the then current market price of the publicly traded common units, we entered into a value assurance agreement with each of the purchasers of the subordinated units. The value assurance agreements require us to pay to the holders an amount per fiscal year, payable on a quarterly basis, equal to the difference between $1.85 per unit and the actual amount distributed during that period. The value assurance agreements will expire upon the earlier of the conversion of the subordinated units to common units, or June 8, 2006.

Also in connection with our strategic restructuring:

- we appointed James C. Flores as our Chairman of the Board and Chief Executive Officer and we appointed a new Chief Operating Officer, Chief Financial Officer, and General Counsel and Secretary;
- certain of our employees received transaction-related bonuses and other payments and vested in benefits in accordance with the terms of our employee benefit plans;
- we entered into a separation agreement with PAA whereby, among other things, (1) we agreed to indemnify PAA, its general partner, and its subsidiaries against (a) any claims related to the upstream business, whenever arising, and (b) any claims related to federal or state securities laws or the regulations of any self-regulatory authority, or other similar claims, resulting from alleged acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries occurring on or before June 8, 2001, and (2) PAA agreed to indemnify us and our subsidiaries against any claims related to the midstream business, whenever arising;
- we entered into a pension and employee benefits assumption and transition agreement pursuant to which we and the general partner of PAA agreed to the transition of certain employees to the general partner, our provision of certain benefits with respect to the transfer, and our provision of transition-related services; and
- we agreed to contribute 287,500 subordinated units to the general partner of PAA to be used for performance option grants to officers and key employees of the general partner.

Oil Production Operations

We have a 100% working interest in five producing fields in the Sunniland Trend in south Florida. We acquired 50% of our interest in these fields in 1993 and the remaining 50% in 1994. At the time of our initial acquisition, production net to the 100% working interest averaged approximately 1,800 barrels of oil per day and proved reserves were approximately 10 MMBbls. In 2002 net production from these properties averaged 2,658 barrels of oil per day and proved reserves were 16.3 MMBbls at December 31, 2002. In 2002 we spent $3.4 million on capital projects, primarily facility enhancements and abandonment of inactive wells. In 2003 we expect to spend $3.7 million on artificial lift projects, facility upgrades and idle well abandonments.

The following tables set forth certain information with respect to the reserves of our Florida properties based upon reserve reports prepared by the independent petroleum consulting firm of Netherland, Sewell & Associates, Inc. The reserve volumes and values were determined under the method prescribed by the Securities and Exchange Commission, or SEC, which requires the application of year-end prices for each year, held constant throughout the projected reserve life. The amounts presented exclude reserves attributable to discontinued operations (see Note 20 to the consolidated financial statements).

	As of or for the Year Ended December 31,		
	2002	2001	2000
		Oil (MBbls)	
Proved Reserves			
Beginning balance	17,343	18,775	23,709
Revision of previous estimates	(60)	(2,470)	(4,092)
Extensions, discoveries, improved recovery and other additions	—	1,992	—
Production	(970)	(954)	(842)
Ending balance	16,313	17,343	18,775
Proved Developed Reserves			
Beginning balance	15,456	17,853	19,383
Ending balance	14,499	15,456	17,853
PV-10 ($/000s)(1)			
Proved developed	$73,656	$21,124	$37,271
Proved undeveloped	14,258	5,421	3,939
Total Proved	$87,914	$26,545	$41,210
Standardized measure	$73,339	$26,545	$41,210
Average year-end realized oil price, per Bbl(2)	$ 20.25	$ 9.82	$ 11.03
December 31 NYMEX WTI spot price, per Bbl	$ 31.20	$ 19.84	$ 26.80

(1) The PV-10 and standardized measure have been reduced to reflect applicable abandonment costs. PV-10 represents the standardized measure before deducting estimated future income taxes.

(2) Price in effect at year end with adjustments based on location and quality of oil.

There are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reservoir engineering is a subjective process of estimating the recovery from underground accumulations of oil that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the Present Value of Proved Reserves shown above represents estimates only and should not be construed as the current market value of the estimated oil reserves attributable to our properties. The information set forth in the preceding tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. See Item 7. — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Factors That May Affect Future Results".

In accordance with the SEC guidelines, the reserve engineers' estimates of future net revenues from our properties and the present value thereof are made using oil sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. The oil price in effect at December 31, 2002 is based on the year-end oil price with variations based on location and quality of oil. The overall average year-end price used in the reserve report as of December 31, 2002 was $20.25 per barrel of oil. See "Product Markets and Major Customers". Historically, the prices for oil have been volatile and are likely to continue to be volatile in the future. See Item 7. — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Factors That May Affect Future Results".

Since December 31, 2001, we have not filed any estimates of total proved net oil reserves with any federal authority or agency other than the SEC.

Productive Wells and Acreage

As of December 31, 2002, we had working interests in 16 gross (16 net) active producing oil wells. At December 31, 2002 we had working interests in 12,025 gross, 12,025 net, developed acres and 73,842 gross, 71,627 net, undeveloped acres, all located in the state of Florida. Less than 10% of total net undeveloped acres are covered by leases that expire in the next five years.

Drilling Activities

No wells were drilled in 2002. In 2001 we participated in 1 gross (0.5 net) dry exploratory well on a property outside Florida. In 2000 we drilled 2 gross (2 net) productive oil development wells on our Florida properties.

Production and Sales

The following table presents certain information with respect to oil production and sales attributable to our properties, the revenue derived from the sale of such production, average sales prices received and average production costs during the three years ended December 31, 2002, 2001 and 2000.

	Year Ended December 31,		
	2002	2001	2000
Production (MBbls)	970	954	842
Sales (MBbls)	869	1,060	701
Average NYMEX price per Bbl	$26.15	$26.01	$30.25
Average hedge cost per Bbl	(0.71)	(1.11)	(9.37)
Average differential per Bbl(1)			
Quality	(3.97)	(9.77)	(5.70)
Transportation costs	(4.34)	(4.20)	(5.35)
Average realized price per Bbl	17.13	10.93	9.83
Production expenses per Bbl	(7.52)	(6.98)	(8.43)
Gross margin per Bbl	$ 9.61	$ 3.95	$ 1.40

(1) Oil transportation costs are included in costs and expenses in the consolidated statement of income.

PAA is the exclusive purchaser of all of our equity oil production. We are currently negotiating a new oil marketing agreement with PAA to, among other things, add a definitive term to the agreement and provide that PAA will use its reasonable best efforts to obtain the best price for our oil production. There can be no assurance, however, that we will enter into a new oil marketing agreement with PAA.

Product Markets and Major Customers

Our revenues are highly dependent upon the prices of, and demand for, oil. Historically, the markets for oil have been volatile, and are likely to continue to be volatile in the future. The prices we receive for our oil production and the levels of such production are subject to wide fluctuations and depend on numerous factors beyond our control, including the condition of the United States and world economies (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic government regulation, legislation and policies. Decreases in the prices of oil have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow. See "Item 7. — "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Factors That May Affect Future Results".

To manage our exposure to commodity price risks, we utilize various derivative instruments to hedge our exposure to price fluctuations on oil sales. Our hedging arrangements provide us protection on the hedged volumes if oil prices decline below the prices at which these hedges are set, however, ceiling prices in our hedges may cause us to receive less revenue on the hedged volumes than we would receive in the absence of hedges. See Item 7A — "Quantitative and Qualitative Disclosures about Market Risks".

Substantially all of our production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil production.

PAA is the exclusive purchaser of all of our equity oil production. The following table reflects for the year ended December 31, 2000, during which period PAA was consolidated in our financial statements, customers accounting for more than 10% of consolidated sales (excluding hedging effects):

	Percentage of Consolidated Sales(1)
Marathon Ashland Petroleum	12%
	Percentage of Oil Sales(2)
Conoco Inc.	55%
ExxonMobil	33%

(1) Pertains to operations of PAA. Represents percent of oil and gas sales revenues plus marketing, transportation, storage and terminalling revenues.

(2) Represents entities that purchased our equity oil production from PAA.

If we were to lose PAA as the exclusive purchaser of our equity production, we believe such loss would not have a material adverse effect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions.

We recommend you review PAA's Annual Report on Form 10-K for the year ended December 31, 2002, and other applicable SEC filings by PAA, for a discussion of PAA's major customers.

Competition

Competitors of our upstream activities include major integrated oil and gas companies, and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our larger upstream competitors possess and employ financial and personnel resources substantially greater than those available to us. Such companies are able to pay more for productive oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for capital available for investment in the oil and gas industry.

We recommend you review PAA's Annual Report on Form 10-K for the year ended December 31, 2002, and other applicable SEC filings by PAA, for a discussion of PAA's competition.

Regulation

We recommend you review PAA's Annual Report on Form 10-K for the year ended December 31, 2002, and other applicable SEC filings by PAA, for a discussion of regulations related to the midstream business. Our discussion on regulation below relates primarily to our upstream business.

Our upstream operations are subject to extensive regulations. Many federal, state and local departments and agencies are authorized by statute to issue and have issued laws and regulations binding on the oil and gas industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the oil industry increases our cost of doing business and, consequently, affects our profitability. However, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors. Due to the myriad of complex federal, state and local regulations that may affect us, directly or indirectly, you should not rely on the following discussion of certain laws and regulations as an exhaustive review of all regulatory considerations affecting our operations.

OSHA

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard, the U.S. Environmental Protection Agency, or EPA, community-right-to-know regulations, and similar state statutes require that we maintain certain information about hazardous materials used or produced in our operations and that we provide this information to our employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

Regulation of Production

The production of oil and gas is subject to regulation under a wide range of federal and state statutes, rules, orders and regulations. State and federal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The State of Florida has regulations governing conservation matters, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from oil and gas wells and the regulation of the spacing, plugging and abandonment of wells. Florida also has the right to restrict production to the market demand for oil and gas. Moreover, Florida imposes an ad valorem, production or severance tax with respect to production and sale of oil and gas within its jurisdiction.

Pipeline Regulation

In our upstream business, we have pipelines to deliver our production to sales points. Our pipelines are subject to certain regulations of the U.S. Department of Transportation, or DOT. In addition, we must permit access to and copying of records, and must make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable requirements.

Environmental

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to safety, health and environmental protection, including the generation, storage, handling, emission, and transportation of materials and discharge of materials into the environment. Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas; and impose substantial liabilities for pollution resulting from our operations. The permits required for various of our operations are subject to revocation, modification and renewal by issuing authorities.

As with the oil and gas industry generally, our compliance with existing and anticipated laws and regulations increases our overall cost of business, including our capital costs to construct, maintain, upgrade and close equipment and facilities. Although these regulations affect our capital expenditures and earnings, we believe that they do not affect our competitive position because our competitors that comply with such laws and regulations are similarly affected. Environmental laws and regulations have historically been subject to change, and we are unable to predict the ongoing cost to us of complying with these laws and regulations or the future impact of such laws and regulations on our operations. If a person violates these environmental laws and regulations and any related permits, they may be subject to significant administrative, civil and criminal penalties, injunctions and construction bans or delays. If we were to discharge hydrocarbons or hazardous substances into the environment, we could, to the extent the event is not insured, incur substantial expense, including both the cost to comply with applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

Although we obtained environmental studies on our properties in Florida, and we believe that such properties have been operated in accordance with standard oil field practices, current or future local, state and federal environmental laws and regulations may require substantial expenditures to remediate the properties or to otherwise comply with such rules and regulations.

A portion of our Florida properties are located within the Big Cypress National Preserve and our operations therein are subject to regulations administered by the National Park Service, or NPS. Under such regulations, a master plan of operations has been approved by the Regional Director of the NPS. The master plan of operations is a comprehensive plan of practices and procedures for our drilling and production operations designed to minimize the effect of such operations on the environment. We must modify the master plan of operations and secure permits from the NPS for new wells that require the use of additional land for drilling operations. The master plan of operations also requires that we restore the surface property affected by drilling and production operations upon cessation of these activities. We do not anticipate that expenditures required to comply with such regulations will have a material adverse effect on our operations.

Other Business Matters

Without successful drilling, acquisition or exploitation operations, our oil and gas reserves and revenues will decline. Drilling activities are subject to numerous risks, including the risk that no commercially viable oil or gas production will be obtained. Our decision to purchase, explore, exploit or develop an interest or property will depend in part on the evaluation of data obtained through geophysical and geological analyses and engineering studies, the results of which are often inconclusive or subject to varying interpretations. See "— Oil and Gas Reserves". The cost of drilling, completing and operating wells is often uncertain. Drilling may be curtailed, delayed or canceled as a result of many factors, including title problems, weather conditions, compliance with government permitting requirements, shortages of or delays in obtaining equipment, reductions in product prices or limitations in the market for products. The availability of a ready market for our oil production also depends on a number of factors, including the demand for and supply of oil and the proximity of reserves to pipelines or trucking and terminal facilities. See "— Product Markets and Major Customers".

Substantially all of our oil production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could cause us to seek transportation alternatives, which in turn could result in increased transportation costs to us or involuntary curtailment of a significant portion of our oil and gas production.

Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including blowouts, cratering, oil spills and fires, each of which could result in damage to or destruction of oil and gas wells, production facilities or other property, or injury to persons. The relatively deep drilling conducted by us from time to time involves increased drilling risks of high pressures and mechanical difficulties, including stuck pipe, collapsed casing and separated cable.

Our upstream properties may experience damage as a result of an accident or other natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damages and suspension of operations. We maintain insurance of various types that we consider to be adequate to cover our upstream operations and properties. The insurance covers all of our upstream assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with our operations. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences.

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interferes with the use of such properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. Title investigation is made and title opinions of local counsel are generally obtained only before commencement of drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to such properties are subject to encumbrances in certain cases, such as customary interests generally retained in connection with acquisition of real property, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens and minor easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition by us, we believe that none of such burdens will materially detract from the value of such properties or from our interest therein or will materially interfere with their use in the operation of our business.

Spin-off Agreements

In connection with the spin-off of PXP, we entered into the following agreements:

Master Separation Agreement

Overview. We entered into a master separation agreement on July 3, 2002 with PXP. The master separation agreement provides for the separation of substantially all of our upstream assets and liabilities, other than our Florida operations. The master separation agreement provides for, among other things:

- the separation;
- cross-indemnification provisions;
- allocation of fees related to these transactions between us and PXP;
- other provisions governing our relationship with PXP, including mandatory dispute arbitration, sharing information, confidentiality and other covenants;
- a noncompetition provision; and
- us entering into the ancillary agreements discussed below with PXP.

Separation. To effect the separation, on July 3, 2002, we transferred to PXP assets and liabilities related to our upstream business other than our Florida operations, including the capital stock of Arguello Inc., Plains Illinois Inc., PMCT, Inc. and Plains Resources International Inc., miscellaneous upstream assets and related hedging agreements. PXP assumed the liabilities associated with the transferred assets and businesses. We also transferred to PXP additional assets and liabilities, including remaining upstream agreements and permits that require consent to transfer and office furniture and equipment, and PXP will sublease a portion of our office space. Except as set forth in the master separation agreement, no party is making any representation or warranty as to the assets or liabilities transferred as a part of the separation, and all assets are being transferred on an "as is, where is" basis.

We agreed to take such further actions as PXP may reasonably request to more effectively complete the transfers of assets and liabilities described above, to protect and enjoy all rights and benefits we had with respect thereto and as otherwise appropriate to carry out the transactions contemplated by the master separation agreement.

Indemnification. The master separation agreement provides for cross-indemnities intended to place sole financial responsibility on PXP for all liabilities associated with the current and historical businesses and operations PXP conducts after giving effect to the separation, regardless of the time those liabilities arise, and to place sole financial responsibility for liabilities associated with our other businesses with us and our other subsidiaries. The master separation agreement also contains indemnification provisions under which we and PXP each indemnify the other with respect to breaches by the indemnifying party of the master separation agreement or any of the ancillary agreements described below. We agree to indemnify PXP against liabilities arising from misstatements or omissions in the various offering documents for the exchange offer related to PXP's 8.75% notes or the spin-off, including related prospecti or in documents to be filed with the SEC in connection therewith if such information was provided by us. PXP agrees to indemnify us and our other subsidiaries against liabilities arising from misstatements or omissions in the various offering documents for the exchange offer related to PXP's 8.75% notes or the spin-off including related prospecti or in documents to be filed with the SEC in connection therewith, except for information regarding and provided by us for inclusion in such documents.

The master separation agreement contains a general release under which we released PXP, and PXP released us and our subsidiaries, affiliates, successors and assigns from any liabilities arising from events between us or our subsidiaries on the one hand, and PXP on the other hand, occurring on or before the separation, including events in connection with activities to implement the separation and the spin-off. The general release does not apply to obligations under the master separation agreement or any ancillary agreement, to liabilities transferred to PXP, to future transactions between us and PXP, or to specified contractual arrangements.

Other provisions. The master separation agreement also provides for: (1) mandatory arbitration to settle disputes between us, and our subsidiaries, and PXP; (2) exchange of information between PXP and us for purposes of conducting our operations, meeting regulatory requirements, responding to regulatory or judicial proceedings, meeting SEC filing requirements, and other reasons; (3) coordination of the conduct of our annual audits and quarterly reviews so that we may both file our annual and quarterly reports in a timely manner; (4) preservation of legal privileges and (5) maintaining confidentiality of each other's information.

In addition, we and PXP agree to use reasonable efforts to amend the omnibus agreement with PAA to terminate the noncompetition provisions therein and to enter into a new oil marketing agreement with PAA so that the agreement only applies to PXP and to add a definite term to the agreement, and other amendments.

Non-competition. The master separation agreement provides that for a period of three years, (1) we and our subsidiaries will be prohibited from engaging in or acquiring any business engaged in any of the "upstream" activities of acquiring, exploiting, developing, exploring for and producing oil and gas in any state in the United States (except Florida), and (2) PXP will be prohibited from engaging in any of the "midstream" activities of marketing, gathering, transporting, terminalling and storing oil and gas (except to the extent any such activities are ancillary to, or in support of, any of PXP's upstream activities.)

Employee Matters Agreement

The employee matters agreement provided that those employees who work for PXP after the spin-off were transferred to PXP immediately before the spin-off. Neither their transfer nor the spin-off was treated as a termination of their employment for purposes of any benefits under any plans.

Stock options and restricted stock awards. Under the employee matters agreement, as a result of the spin-off, all outstanding options to acquire our common stock at the time of the spin-off were "split" into (1) an equal number of options to acquire our common stock and (2) an equal number of stock appreciation rights, or SARs, with respect to PXP common stock.

The exercise price for our original stock options was also "split" between our new stock options and the SARs based on the relationship of the closing price (with dividend) of our common stock on the spin-off date ($23.05 per share) less the closing price (on a "when-issued" basis) of PXP common stock on the spin-off date ($9.10 per share), both as reported on the NYSE, and such closing price of PXP common stock ($9.10 per share).

Also, unless otherwise provided for in the agreement governing the restricted stock award, at the time of the spin-off all restricted stock awards for our common stock were "split" into (1) restricted stock awards for an equal number of shares of our common stock and (2) restricted stock awards for an equal number of shares of PXP common stock. An employee's or a director's service with PXP counts towards the vesting of their "split" Plains Resources stock options and restricted stock awards even though the employee is no longer employed by us or the director no longer serves on our board of directors. With respect to employees and directors who stay with us, their service at Plains Resources counts towards the vesting of their SARs even though they are not employed by PXP or do not serve on PXP board of directors.

Unless a person is employed by or serves as a director for both PXP and us, termination of employment or service as a director for any reason at either company will count as termination for the same reason at the other company for purposes of vesting and termination of options, SARs, and restricted stock awards. If a person is employed by or serves as a director for both PXP and us, termination for any reason at one company will not count as termination at the other company.

Other plans. Under the employee matters agreement (1) PXP established a nonqualified deferred compensation plan for certain executive officers and, to the extent that any of the executives are participants in our deferred compensation plan, the related assets and liabilities under our plan were transferred to the PXP plan, (2) we transferred our 401(k) plan and welfare benefit plans to PXP and formed a similar 401(k) plan and similar welfare benefit plans, and (3) PXP established plans that mirror our fringe benefits and company policies.

Other. Under the employee matters agreement, we retained liability for all incurred but not reported claims occurring before the spin-off, and PXP is liable for all claims incurred on or after the spin-off related to its employees.

Tax Allocation Agreement

On July 3, 2002, we entered into the tax allocation agreement, which we and PXP amended and restated on November 20, 2002. This agreement provides that, until the spin-off, PXP continued to be included in our consolidated federal income tax group, and PXP's federal income tax liability was included in our consolidated federal income tax liability. The amount of taxes that PXP pays or receives with respect to our consolidated or combined returns in which PXP is included generally are to be determined by multiplying PXP's net taxable income included in our consolidated tax return by the highest marginal tax rate applicable to the income. We are not required to pay PXP for the use of its tax attributes that come into existence before the spin-off until such time as PXP would otherwise be able to utilize such attributes.

In general, the agreement provides that PXP is included in our consolidated group for federal income tax purposes until the time of the spin-off. Each member of a consolidated group is jointly and severally liable for the federal income tax liability of each other member of the consolidated group. Accordingly, although this agreement allocates tax liabilities between us and PXP during the period in which PXP is included in our consolidated group, PXP could be liable if any federal tax liability is incurred, but not discharged, by any other member of our consolidated group. In addition, to the extent our net operating losses are used in the consolidated return to offset PXP's taxable income from operations during the period January 1, 2002 through the spin-off, PXP will reimburse us for the reduction in PXP's federal income tax liability resulting from the utilization of such net operating losses, but such reimbursement shall not exceed $3 million exclusive of any interest accruing under the agreement. A receivable from PXP for $3.0 million is reflected in Other Assets in our consolidated balance sheet at December 31, 2002 for the use of our net operating losses.

Under the terms of this agreement, PXP agrees to indemnify us if the spin-off is not tax-free to us as a result of various actions taken by PXP or with respect to PXP's failure to take various actions.

In addition, PXP agrees that, during the three-year period following the spin-off, without our prior written consent, PXP will not engage in transactions that could adversely affect the tax treatment of the spin-off unless it obtains a supplemental tax ruling from the IRS or a tax opinion acceptable to us of nationally recognized tax counsel to the effect that the proposed transaction would not adversely affect the tax treatment of the spin-off or provide adequate economic security to us to ensure PXP would be able to comply with its obligation under this agreement.

PXP also agrees to be liable for transfer taxes associated with the transfer of assets and liabilities in connection with the separation and the spin-off.

Intellectual Property Agreement

On July 3, 2002 we entered into the intellectual property agreement, which provides that we will transfer to PXP ownership and all rights associated with certain trade names, trademarks, service marks and associated goodwill, including Arguello, Plains, Plains Energy, Plains E&P, Plains Exploration & Production, Plains Illinois, Plains Petroleum, Plains Resources, Plains Resources International, PLX, PMCT, Stocker Resources and the Plains logo. In addition, PXP will grant to us a full license to use certain trade names including Plains Energy and Plains Resources, referred to as the Plains Marks, subject to certain limitations. These licenses are not transferable or assignable without PXP's written consent, except that we may grant our subsidiaries sublicenses to use the Plains Marks.

We will not attempt to register a trade name or trademark that incorporates or is confusingly similar to the Plains Marks. Also, if we develop new trademarks using the name "Plains," we must first obtain PXP's written approval. PXP will own such new trademarks and they will be considered subject to the terms of this agreement.

The intellectual property agreement provides that we will conform the nature and quality of our products and services offered in connection with the Plains Marks to PXP's reasonable design and quality standards. Further, we will use the Plains Marks only in connection with our business.

Plains Exploration & Production Transition Services Agreement

On July 3, 2002 we entered into the Plains Exploration & Production transition services agreement, which provides that we will provide PXP the following services, on an interim basis:

- management services, including managing PXP's operations, evaluating investment opportunities for PXP, overseeing PXP's upstream activities, and staffing;
- tax services, including preparing tax returns and preparing financial statement disclosures;
- accounting services, including maintaining general ledgers, preparing financial statements and working with PXP's auditors;
- payroll services, including payment processing and complying with regulations relating to payroll services;
- insurance services, including maintaining for the interim period the existing insurance that we provide for PXP;
- employee benefits services, including administering and maintaining the employee benefit plans that cover PXP's employees;
- legal services, including typical and customary legal services; and
- financial services, including helping PXP raise capital, preparing budgets and executing hedges.

Through December 31, 2002 we have charged PXP $10.8 million of the $30.0 million allowed under this agreement to reimburse us for our costs of providing such services. We will continue to provide services under this agreement until June 16, 2003, unless we and PXP decide to terminate the agreement earlier. We do not expect to make significant additional charges to PXP under this agreement.

This transition services agreement provides that we will not be liable to PXP with respect to the performance of the services, except in the case of gross negligence or willful misconduct in providing the services. We will indemnify PXP for any liabilities arising from such gross negligence or misconduct. PXP will indemnify us for any liabilities arising directly from the performance of the services by us, except for liabilities caused by our gross negligence or willful misconduct. We disclaim all warranties and make no representations as to the quality, suitability or adequacy of the services provided.

Plains Resources Transition Services Agreement

On July 3, 2002 we entered into the Plains Resources transition services agreement, under which PXP will provide us the following services on an interim basis beginning on a date to be determined by both us and PXP upon the transfer by us of substantially all of our employees to PXP:

- tax services, including preparing tax returns and preparing financial statement disclosures;
- accounting services, including maintaining general ledgers, preparing financial statements and working with our auditors;
- payroll services, including payment processing and complying with regulations relating to payroll services;
- employee benefits services, including administering and maintaining the employee benefit plans that cover our employees;

- legal services, including typical and customary legal services; and
- financial services, including helping us raise capital, preparing budgets and executing hedges.

The services provided by PXP under the Plains Resources transition services agreement and the services provided by us under the Plains Exploration & Production transition services agreement are substantially similar, except that:

- the Plains Resources transition services agreement does not cover management services, insurance services or operational services;
- the tax services provided under the Plains Resources transition services agreement are not subject to the tax allocation agreement; and
- the legal services provided under the Plains Exploration & Production transition services agreement include legal services that we have historically provided for us and our subsidiaries.

PXP will charge us on a monthly basis its costs of providing such services. No amounts had been charged under this agreement through December 31, 2002.

In addition, we and PXP may identify additional services that PXP will provide to us under this agreement in the future. The terms and costs of these additional services will be mutually agreed upon by us and Plains Resources. PXP may allow one of its subsidiaries or a qualified third party to provide the services under this agreement, but PXP will be responsible for the performance of the services.

PXP will be obligated to provide the services with substantially the same degree of care as it employs for its own operations. PXP may change the manner in which it provides the services so long as it deems such change to be necessary or desirable for its own operations.

This transition services agreement provides that PXP will not be liable to us with respect to the performance of the services, except in the case of gross negligence or willful misconduct in providing the services. PXP will indemnify us for any liabilities arising from such gross negligence or misconduct. We will indemnify PXP for any liabilities arising directly from PXP's performance of the services, except for liabilities caused by PXP's gross negligence or willful misconduct. PXP disclaims all warranties and makes no representations as to the quality, suitability or adequacy of the services provided.

The term of this agreement expires on June 8, 2003 unless we and PXP decide to terminate the agreement earlier. We and PXP may agree to extend the term if necessary or desirable.

Technical Services Agreement

On July 3, 2002 we entered into the technical services agreement, which provides that, beginning on a date to be determined by us and PXP, PXP will provide Calumet Florida certain engineering and technical support services required to support operation and maintenance of the oil and gas properties owned by Calumet, including geological, geophysical, surveying, drilling and operations services, environmental and other governmental or regulatory compliance related to oil and gas activities and other oil and gas engineering services as requested, and accounting services.

We will reimburse PXP for its costs to provide these services. No amounts had been charged under this agreement through December 31, 2002.

In addition, we and PXP may identify additional services that PXP will provide to us under this agreement in the future. The terms and costs of these additional services will be mutually agreed upon by us and PXP. PXP may allow one of its subsidiaries or a qualified third party to provide the services under this agreement, but PXP will be responsible for the performance of the services.

We and PXP may agree to specific performance metrics that it must meet. Where no metrics are provided, PXP will (1) perform the services in accordance with the policies and procedures in effect before this agreement, (2) exercise the same care and skill as it exercises in performing similar services for its subsidiaries, and (3) in cases where there is common personnel, equipment or facilities for services provided to PXP's subsidiaries and us, not favor us or PXP's subsidiaries over the other. PXP may change the manner in which it provides the services so long as it is making similar changes to the services it provides to its subsidiaries. PXP is not obligated to provide any service to the extent it is impracticable as a result of causes outside of its control.

The technical services agreement provides that PXP will not be liable to us or Calumet with respect to the performance of the services, except in the case of gross negligence or willful misconduct in providing the services. PXP will indemnify us and Calumet for any liabilities arising from such gross negligence or misconduct. We will indemnify PXP for any liabilities arising directly from the performance of the services, except for liabilities caused by PXP's gross negligence or willful misconduct. PXP disclaims all warranties and makes no representations as to the quality, suitability or adequacy of the services provided.

PXP will provide the services until (1) Calumet is no longer our subsidiary, (2) Calumet transfers substantially all of its assets to a person that is not a subsidiary of us, (3) the third anniversary of the date of this agreement or (4) when all the services are terminated as provided in the agreement. We may terminate the agreement as to some or all of the services at any time by giving PXP at least 90 days' written notice.

Employees

As of February 28, 2003, we had 14 full-time employees (not including our Chief Executive Officer and Chief Financial Officer, who also devote a portion of their time and efforts to PXP), none of whom is represented by any labor union. Of such full-time employees, 12 are field personnel involved in oil and gas producing activities.

Risk Factors

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results ad financial condition, as well as adversely affect the value of an investment in our common stock.

We are highly dependent upon the earnings and distributions of PAA.

As of December 31, 2002, the present value of our proved oil reserves was approximately $87.9 million. We own 6.6 million common units, 1.3 million Class B common units and 4.5 million subordinated units of PAA. The closing price of publicly traded PAA common units, as reported on the New York Stock Exchange, was $24.40 on December 31, 2002. The Class B common units and the subordinated units are not publicly traded but do receive cash distributions from PAA. PAA's partnership agreement contains provisions which, upon the occurrence of certain future events, will result in the conversion of the subordinated units to common units. In 2002, we had oil revenues of $18.7 million while distributions received from PAA attributable to our general and limited partner interests totaled $29.1 million.

PAA's financial performance will directly affect our financial performance and the market value performance of PAA's limited partner interests will directly impact the value of our assets. A significant decline in PAA's earnings would have a corresponding negative impact on our earnings. Likewise, a significant decline in the value of PAA's common units would have a corresponding negative impact on the value of our assets.

In addition, cash from PAA distributions on its general partner and limited partner interests is one of our primary sources of liquidity. If PAA could not, for any reason, make its minimum quarterly distribution payments on its limited partner and general partner interests, this would impair our ability to meet our short and long-term cash needs, including normal recurring operating needs, debt service obligations, contingencies and capital expenditures. Further, PAA's inability to make its minimum quarterly distribution payments would trigger our payment obligations under the value assurance agreements, which would compound the negative impact on our ability to meet our short and long-term capital needs.

We have also entered into an oil marketing agreement with PAA under which PAA is the exclusive purchaser of all of our net oil production. We generally do not require letters of credit or other collateral form PAA to support our trade receivables. Accordingly, a material adverse change in PAA's financial condition could adversely impact our ability to collect our receivables from PAA and thereby affect our financial condition.

We urge you to review PAA's SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2002, for risks associated with PAA's business.

Our levels of indebtedness may limit our financial and operating flexibility.

We have a substantial amount of debt and the ability to incur substantially more debt. We have a $45.0 million secured term loan facility, which is collateralized by a pledge of the equity of our subsidiaries and 4,950,000 of our PAA common units. The term loan is repayable in 10 quarterly installments of $4.5 million each commencing on February 28, 2003 with a final maturity on May 31, 2005.

We and all of our subsidiaries must comply with various covenants contained in our secured term loan facility, which, among other things, limit the ability of us and our subsidiaries to:

- incur additional debt or liens;
- enter into leases;
- sell assets;
- make loans or investments;
- change the nature of our business or operations;
- guarantee other indebtedness;
- enter into certain types of hedge agreements;
- enter into take-or-pay arrangements;
- merge or consolidate; and
- enter into transactions with affiliates.

In addition, if an event of default exists, the term loan prohibits us from paying dividends or repurchasing or redeeming shares of any class of our capital stock.

Our substantial debt could have important consequences to you. For example, it could:

- increase our vulnerability to general adverse economic and industry conditions;
- limit our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise realize the value of our assets and opportunities fully because of the need to dedicate a substantial portion of our cash flow to payments on our debt or to comply with any restrictive terms of our debt;

- limit our flexibility in planning for, or reacting to, changes in the industry in which we operate; and
- place us at a competitive disadvantage as compared to our competitors that have less debt.

In addition, if we fail to comply with the terms of our debt, our lenders will have the right to accelerate the maturity of that debt and foreclose upon the collateral securing that debt. Realization of any of these factors could adversely affect our financial condition.

Volatile oil and gas prices could adversely affect our financial condition and results of operations.

Our success is largely dependent on oil prices, which are extremely volatile. Any substantial or extended decline in the price of oil below current levels will have a material adverse effect on our business operations and future revenues. Moreover, oil prices depend on factors we cannot control, such as:

- supply and demand for oil and expectations regarding supply and demand;
- weather;
- actions by the Organization of Petroleum Exporting Countries, or OPEC;
- political conditions in other oil-producing countries including the possibility of insurgency or war in such areas;
- general economic conditions in the United States and worldwide; and
- governmental regulations.

With respect to our business, prices of oil will affect:

- our revenues, cash flows and earnings;
- our ability to attract capital to finance our operations and the cost of such capital;
- the amount that we are allowed to borrow; and
- the value of our oil and gas properties.

Any prolonged, substantial reduction in the demand for oil, or distribution problems in meeting this demand, could adversely affect our business.

Our success is materially dependent upon the demand for oil. The availability of a ready market for our oil production depends on a number of factors beyond our control, including the demand for and supply of oil and gas, the availability of alternative energy sources, the proximity of reserves to, and the capacity of, oil and gas gathering systems, pipelines or trucking and terminal facilities. We may also have to shut-in some of our wells temporarily due to a lack of market or adverse weather conditions including hurricanes. If the demand for oil diminishes, our financial results would be negatively impacted.

In addition, there are limitations related to the methods of transportation for our production. Substantially all of our oil production is transported by pipelines and trucks owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil production, any of which could have a negative impact on our results of operation and cash flows.

The war in Iraq, recent terrorist activities and the potential for other global events could adversely affect our business.

The United States is at war with Iraq. Additionally, on September 11, 2001, the United States was the target of terrorist attacks of unprecedented scope, and the United States and other countries instituted military action in response. These conditions have caused instability in the world financial markets and may generate global economic instability. The continued threat of terrorism and the impact of military or other action have led to and will likely lead to increased volatility in prices for oil and gas and could affect the markets for our operations. In particular, it appears the price of oil has become increasingly volatile since commencement of war in Iraq. Further, the United States government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on the ultimate magnitude, could have a material adverse affect on our business.

If we are unable to replace the reserves that we have produced, our reserves and revenues will decline.

Our future success depends in part on our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable which, in itself, is dependent on oil and gas prices. Without continued successful exploitation, acquisition or exploration activities, our reserves and revenues will decline as a result of our current reserves being depleted by production. We may not be able to find or acquire additional reserves at acceptable costs.

We may not be successful in acquiring, exploiting, developing or exploring for oil and gas properties.

The successful acquisition, exploitation or development of, or exploration for, oil and gas properties requires an assessment of recoverable reserves, future oil and gas prices and operating costs, potential environmental and other liabilities, and other factors. These assessments are necessarily inexact. As a result, we may not recover the purchase price of a property from the sale of production from the property, or may not recognize an acceptable return from properties we do acquire. In addition, our exploitation and development and exploration operations may not result in any increases in reserves. Our operations may be curtailed, delayed or canceled as a result of:

- inadequate capital or other factors, such as title problems;
- weather;
- compliance with governmental regulations or price controls;
- mechanical difficulties; or
- shortages or delays in the delivery of equipment.

In addition, exploitation and development costs may greatly exceed initial estimates. In that case, we would be required to make unanticipated expenditures of additional funds to develop these projects, which could materially adversely affect our business, financial condition and results of operations.

Furthermore, exploration for oil and gas has inherent and historically higher risk than exploitation and development activities. Future reserve increases and production may be dependent on our success in our exploration efforts, which may be unsuccessful.

Estimates of oil and gas reserves depend on many assumptions that may be inaccurate. Any material inaccuracies could adversely affect the quantity and value of our oil and gas reserves.

The proved oil reserve information included in this document represents only estimates. These estimates are based on reports prepared by independent petroleum engineers. The estimates were calculated using oil prices in effect on the date indicated in the reports. Any significant price changes will have a material effect on the quantity and present value of our reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including:

- historical production from the area compared with production from other comparable producing areas;
- the assumed effects of regulations by governmental agencies;
- assumptions concerning future oil and gas prices; and
- assumptions concerning future operating costs, severance and excise taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities of oil and gas that are ultimately recovered;
- the timing of the recovery of oil and gas reserves;
- the production and operating costs incurred; and
- the amount and timing of future development expenditures.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves will vary from estimates and the variances may be material.

The discounted future net revenues included in this document should not be considered as the market value of the reserves attributable to our properties. As required by the SEC, the estimated discounted future net revenues from proved reserves are generally based on prices and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net revenues will also be affected by factors such as:

- the amount and timing of actual production;
- supply and demand for oil and gas; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor, which the SEC requires to be used to calculate discounted future net revenues for reporting purposes, is not necessarily the most appropriate discount factor based on the cost of capital in effect from time to time and risks associated with our business and the oil and gas industry in general.

The geographic concentration and lack of marketable characteristics of our oil reserves may have a greater effect on our ability to sell our oil compared to other companies.

All of our oil reserves are located in Florida. Because our reserves are not as diversified geographically as many of our competitors, our business is more subject to local conditions than other, more diversified companies. Any regional events, including price fluctuations, natural disasters, and restrictive regulations, that increase costs, reduce availability of equipment or supplies, reduce demand or limit our production may impact our operations more than if our reserves were more geographically diversified.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and gas business involves certain operating hazards such as:

- well blowouts;
- cratering;
- explosions;
- uncontrollable flows of oil, gas or well fluids;
- fires;
- pollution; and
- releases of toxic gas.

Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition, or could result in a loss of our properties.

Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Upon renewal in June 2002, our cost of insurance increased substantially over the prior year's amount. In addition, we increased deductibles and decreased or eliminated certain types of coverages to mitigate the cost increase. Insurance costs are expected to continue to increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

Governmental agencies and other bodies, including those in Florida, might impose regulations that increase our costs and may terminate or suspend our operations.

Our business is subject to federal, state and local laws and regulations as interpreted by governmental agencies and other bodies, including those in Florida, vested with much authority relating to the exploration for, and the development, production and transportation of, oil and gas, as well as environmental and safety matters. Existing laws and regulations could be changed, and any changes could increase costs of compliance and costs of operating drilling equipment or significantly limit drilling activity.

Environmental liabilities could adversely affect our financial condition.

The oil and gas business is subject to environmental hazards, such as oil spills, gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These environmental hazards could expose us to material liabilities for property damages, personal injuries or other environmental harm, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things:

- well drilling or workover, operation and abandonment;
- waste management;
- land reclamation;
- financial assurance under the Oil Pollution Act of 1990; and
- controlling air, water and waste emissions.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production, and may affect our costs of acquisitions.

In addition, environmental laws may, in the future, cause a decrease in our production or cause an increase in our costs of production, development or exploration. Pollution and similar environmental risks generally are not fully insurable.

Our acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make acquisitions or realize anticipated benefits of those acquisitions.

Our growth strategy may include acquiring midstream and upstream businesses and properties. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully. Furthermore, acquisitions involve a number of risks and challenges, including:

- diversion of management's attention;
- the need to integrate acquired operations;
- potential loss of key employees of the acquired companies;
- potential lack of operating experience in a geographic market of the acquired business; and
- an increase in our expenses and working capital requirements.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses or realize other anticipated benefits of those acquisitions.

In addition, under the spin-off agreements, until July 3, 2005, we are prohibited from acquiring any upstream business or properties in the United States outside of Florida. Thus, until after July 3, 2005, our upstream acquisition prospects are limited to Florida and outside of the United States.

We intend to continue hedging a portion of our production, which may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas.

We reduce our exposure to the volatility of oil prices by actively hedging a portion of our production. Hedging also prevents us from receiving the full advantage of increases in oil prices above the fixed amount specified in the hedge agreement. In a typical hedge transaction, we have the right to receive from the hedge counterparty the excess of the fixed price specified in the hedge agreement over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we must pay the counterparty this difference multiplied by the quantity hedged even if we had insufficient production to cover the quantities specified in the hedge agreement. Accordingly, if we have less production than we have hedged when the floating price exceeds the fixed price, we must make payments against which there are no offsetting sales of production. If these payments become too large, the remainder of our business may be adversely affected. In addition, our hedging agreements expose us to risk of financial loss if the counterparty to a hedging contract defaults on its contract obligations.

Loss of key executives and failure to attract qualified management could limit our growth and negatively impact our operations.

Successfully implementing our strategies will depend, in part, on our management team. The loss of members of our management team could have an adverse effect on our business. Our exploration and exploitation success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced engineers, geoscientists and other professionals. Competition for experienced professionals is extremely intense. If we cannot attract or retain experienced technical personnel, our ability to compete could be harmed.

We and PXP share and, therefore will compete for, the time and effort of our personnel who provide services to PXP, including directors and officers.

Because certain of our officers and directors provide services to PXP, conflicts of interest could arise between PXP, on the one hand, and us, on the other. Additionally, some of these officers and directors own and are awarded from time to time shares, or options to purchase shares, or stock appreciation rights of PXP. Accordingly, their financial interests may not always be aligned with ours and could create, or appear to create, potential conflicts of interest when these officers and directors are faced with decisions that could have different implications for us and PXP.

To preserve the tax-free status of the spin off, we may be limited in taking future actions.

If we experience a change of control, fail to continue the active conduct of our trade or business or fail to comply with the representations underlying our tax ruling or supplemental tax ruling relating to the spin-off, the tax-free treatment of the spin off might be lost. If there are any corporate level taxes incurred by us as a result of the spin-off for any other reason, we would be responsible for 50% of any such liability and PXP would be responsible for the remaining 50%. The amount of any tax payments would be substantial and may result in events of default under our loan facility. As a result, we likely would not have sufficient financial resources to achieve our growth strategy or, possibly, repay our indebtedness after making these payments.

As a result of the tax principles discussed above, we may be highly limited in our ability to take the following steps in the future:

- issue equity in public or private offerings;
- issue equity as part of the consideration in acquisitions of additional assets; or
- undergo a change of control.

Item 3. *Legal Proceedings*

On September 18, 2002 Stocker Resources Inc., or Stocker, which was the general partner of PXP before it was converted from a limited partnership to a corporation, filed a declaratory judgment action against Commonwealth Energy Corporation, or Commonwealth, in the Superior Court of Orange County, California relating to the termination of an electric service contract. Stocker filed seeking a declaratory judgment that it was entitled to terminate the contract and that Commonwealth has no basis for proceeding against Stocker's related $1.5 million performance bond. Also on September 18, 2002, Stocker was named a defendant in an action brought by Commonwealth in the Superior Court of Orange County, California for breach of the electric service contract. Commonwealth is seeking unspecified damages. Stocker was merged into us in December 2002. Under our master separation agreement with PXP, we are indemnified for damages we incur as a result of this action. We intend to defend our rights vigorously in this matter.

In the ordinary course of our business, we are a claimant or defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

Item 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to a vote of the security holders, through solicitation of proxies or otherwise, during the fourth quarter of the fiscal year covered by this report.

Directors and Executive Officers of Plains Resources

Listed below are our directors and executive officers, their age as of February 28, 2003, and their business experience for the last five years.

Directors

James C. Flores, age 43, Executive Chairman of the Board since December 2002. He was our Chairman of the Board and Chief Executive Officer from May 2001 to December 2002. He was President and Chief Executive Officer of Ocean Energy, Inc., an oil and gas company, from July 1995 until March 1999, and a director of Ocean Energy, Inc. from 1992 until March 1999. In March 1999 Ocean Energy, Inc. was merged into Seagull Energy Corporation, which was the surviving corporation of the merger, and which was renamed Ocean Energy, Inc. Mr. Flores served as Chairman of the Board of the new Ocean Energy, Inc. from March 1999 until January 2000, and as Vice Chairman from January 2000 until January 2001. From January 2001 to May 2001 Mr. Flores managed various private investments. Mr. Flores has been Chairman of the Board, Chief Executive Officer and a Director of PXP since September 2002.

William M. Hitchcock, age 63, Director since 1977. Mr. Hitchcock is a partner and has been President, since December 1996, of Pembroke Capital LLC, an investment firm. In addition, he is Chief Executive Officer of Camelot Oil & Gas, a private oil and gas company. He is also a director of Maxx Petroleum, Ltd., an oil and gas company, Thoratec Laboratories Corporation, a medical device company, and Luna Imaging, Inc., a digital imaging company. From 1992 to 1995, Mr. Hitchcock served as President of Plains Resources International Inc., which was formerly one of our wholly-owned subsidiaries. In addition, he was our Chairman of the Board from August 1981 to October 1992, except for the period from April 1987 to October 1987, when he served as our Vice Chairman.

D. Martin Phillips, age 49, Director since June 2001. Mr. Phillips has been a Managing Director and principal of EnCap Investments L.L.C., or EnCap, a funds management and investment banking firm that focuses exclusively on the oil and gas industry, since November 1989. From 1978 to when he joined EnCap, Mr. Phillips served as Senior Vice President in the Energy Banking Group of NCNB Texas National Bank in Dallas, Texas. Mr. Phillips also serves as a director of Mission Resources Corporation, Breitburn Energy Company LLC, 3TEC Energy Corporation and the Houston Producers' Forum, of which he formerly served as president.

Robert V. Sinnott, age 53, Director since 1994. Mr. Sinnott has been Senior Vice President of Kayne Anderson Investment Management, Inc., an investment management firm, since 1992. He is also a director of Glacier Water Services, Inc., a vended water company, and Plains All American GP LLC, which is the general partner of Plains AAP, L.P., which is in turn the general partner of Plains All American Pipeline, L.P., or PAA. Mr. Sinnott was Vice President and Senior Securities Officer of the Investment Banking Division of Citibank from 1986 to 1992.

J. Taft Symonds, age 63, Director since 1987. Mr. Symonds has been Chairman of the Board of Symonds Trust Co. Ltd., an investment firm, and Chairman of the Board of Maurice Pincoffs Company, Inc., an international marketing firm, since 1978. He is also Chairman of the Board of Tetra Technologies, Inc., a specialty chemical and chemical process company, and a director of

Denali, Inc., a manufacturer of storage tanks and a product and service provider for handling of industrial fluids. Mr. Symonds is also a director of Plains All American GP LLC.

Executive Officers

John T. Raymond, age 32, Chief Executive Officer and President since December 2002. Mr. Raymond served as our President and Chief Operating Officer from November 2001 to December 2002 and as Executive Vice President and Chief Operating Officer from May 2001 to November 2001. In addition, Mr. Raymond served as Director of Corporate Development of Kinder Morgan, Inc. from January 2000 to May 2001, and as Vice President of Corporate Development of Ocean Energy, Inc. from April 1998 to January 2000. Mr. Raymond also served as Vice President of Howard Weil Labouisse Friedrichs, Inc., an energy investment company, from 1992 to April 1998. In addition, Mr. Raymond is a director of Plains All American GP LLC, which is the general partner of Plains AAP LP, which is the general partner of PAA. Mr. Raymond has also been President and Chief Operating Officer of PXP since September 2002.

Stephen A. Thorington, age 47, Executive Vice President and Chief Financial Officer since February 2003. He served as Acting Executive Vice President and Chief Financial Officer from December 2002 to February 2003 when he was appointed to his current position. Mr. Thorington has also been Executive Vice President and Chief Financial Officer of PXP since September 2002. Mr. Thorington was Senior Vice President — Finance and Corporate Development of Ocean Energy, Inc. from July 2001 to September 2002 and Senior Vice President — Finance, Treasury and Corporate Development of Ocean Energy, Inc. from March 1999 to July 2001. He also served as Vice President, Finance and Treasurer of Seagull Energy Corporation from May 1996 to March 1999.

Franklin R. Bay, age 45, is our Senior Vice President of Corporate Development, Chief Legal Officer and Secretary. Mr. Bay has been our Senior Vice President of Corporate Development since February 2002, and he was appointed as Chief Legal Officer and Secretary in December 2002. Pursuant to a transaction services agreement between us and PXP, Mr. Bay also provides some corporate development services to PXP. Prior to joining Plains, Mr. Bay served in various capacities with Enron Corp. for approximately five years, including Vice President of Commercial Operations for Northern Natural Gas Pipeline Company, General Counsel of the Gas Pipeline Group and Head of Broadband Services Emerging Business Group. His previous experience also includes serving in the first Bush Administration as the Deputy General Counsel at the Department of Energy and Deputy Legal Adviser at the State Department. Additionally, he practiced law for nine years with Fulbright & Jaworski and Hutcheson & Grundy and he previously served as a second lieutenant in the United States Marine Corps.

PART II

Item 5. *Market for Registrant's Common Stock and Related Stockholder Matters*

Price Range of Common Stock

Our common stock is listed and traded on the New York Stock Exchange under the symbol "PLX". Prior to December 21, 2001 our common stock was traded on the American Stock Exchange. The number of stockholders of record of our common stock as of February 28, 2003 was 1,046.

The following table sets forth the range of high and low closing sales prices for our common stock as reported on the applicable Stock Exchange Composite Tapes for the periods indicated below.

	High	Low
2002		
Before Spin-off		
1st Quarter	$24.99	$22.35
2nd Quarter	27.75	24.60
3rd Quarter	26.95	21.92
4th Quarter	25.88	20.18
After Spin-off		
4th Quarter	12.51	11.85
2001		
1st Quarter	$23.65	$19.44
2nd Quarter	26.80	19.89
3rd Quarter	29.50	22.76
4th Quarter	27.70	22.20

Dividend Policy

We have not paid cash dividends on shares of our common stock since our inception and do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the amount of dividends we can pay is restricted by provisions of our loan facility.

Series D Cumulative Convertible Preferred Stock

We have outstanding 46,600 shares of Series D Cumulative Convertible Preferred Stock, or Series D Preferred, that have an aggregate stated value of $23.3 million and are redeemable at our option at 140% of stated value. If not previously redeemed or converted, the Series D Preferred will automatically convert into shares of common stock in 2012. Each share of Series D Preferred has a stated value of $500 and bears an annual dividend of $30.00 per share, paid on a quarterly basis.

As a result of the spin-off, the number of shares of our common stock into which the Series D Preferred is convertible increased from 932,000 shares to 1,671,416 shares as a result of the reduction in the conversion price from $25.00 per share of common stock to $13.94 per share. The reduction in the conversion price of the Series D Preferred was determined by multiplying the former conversion price of the Series D Preferred ($25.00) by a fraction, the denominator of which was $22.27 (the closing price per share of our common stock as of the record date for the spin-off), and the numerator of which was $12.42 (the closing price per share of our common stock as of the record date for the spin-off less the agreed on fair market value per share of the PXP common stock distributed in the spin-off). The holder of the Series D Preferred did not receive any PXP securities as a result of the spin off.

Item 6. *Selected Financial Data*

The following selected financial information was derived from, and is qualified by reference to, our consolidated financial statements, including the notes thereto, appearing elsewhere in this report. As a result of the reduction in our ownership interest in PAA in 2001, our investment in PAA is accounted for using the equity method of accounting effective January 1, 2001. In prior periods, PAA is included on a consolidated basis. As a result of the spin-off the historical results of the operations of PXP are reflected in our financial statements as "discontinued operations". This selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and "Item 7. — Management's Discussion and Analysis of Financial Condition and Results of Operations" (in thousands, except per share information).

	Year Ended December 31,				
	2002	2001	2000	1999	1998
Revenues					
Oil sales to PAA	$ 18,662	$ 16,030	$ 10,643	$ 12,478	$ 22,488
Marketing, transportation, storage and terminalling	—	—	6,425,644	10,796,998	3,454,635
Gain on sale of assets(1)	—	—	48,188	16,457	—
	18,662	16,030	6,484,475	10,825,933	3,477,123
Costs and Expenses					
Production expenses	6,536	7,397	5,912	5,118	8,004
Oil transportation expenses	3,775	4,449	3,752	3,740	5,241
General and administrative	5,747	11,083	44,468	27,035	7,560
Marketing, transportation, storage and terminalling	—	—	6,292,615	10,689,308	3,416,274
Unauthorized trading losses and related expenses(2)	—	—	7,963	166,440	7,100
Depreciation, depletion and amortization	4,139	4,816	28,362	23,669	17,119
Reduction in carrying cost of oil and gas properties	—	—	—	—	130,954
	20,197	27,745	6,383,072	10,915,310	3,592,252
Other Income (Expense)					
Equity in earnings of PAA	18,807	18,540	—	—	—
Gains on PAA unit transactions and public offerings(3)	14,512	170,157	—	9,787	60,815
Loss on debt extinguishment	(10,319)	—	(15,148)	(1,545)	—
Interest expense	(5,866)	(8,974)	(39,943)	(31,466)	(26,902)
Interest and other income	239	(312)	7,068	1,150	760
Minority interest in PAA	—	—	(35,565)	40,911	(786)
Income tax expense	(6,106)	(67,072)	(5,628)	26,104	37,930
Income (Loss) From Continuing Operations	9,732	100,624	12,187	(44,436)	(43,312)
Income (loss) from discontinued operations, net of tax	27,800	54,693	28,749	19,105	(19,034)
Cumulative effect of accounting changes, net of tax	—	(1,986)	(121)	—	—
Net Income	37,532	153,331	40,815	(25,331)	(62,346)
Cumulative preferred dividends(4)	(1,400)	(27,245)	(14,725)	(10,026)	(4,762)
Income Available to Common Stockholders	$ 36,132	$126,086	$ 26,090	$ (35,357)	$ (67,108)
Income From Continuing Operations Per Share					
Basic	$ 0.35	$ 3.48	$ (0.14)	$ (3.16)	$ (2.86)
Diluted	$ 0.34	$ 2.81	$ (0.14)	$ (3.16)	$ (2.86)

(table and footnotes continued on following page)

	At or Year Ended December 31,				
	2002	2001	2000	1999	1998
Balance Sheet Data					
Working capital (deficit)	$(11,971)	$ (9,969)	$ 20,289	$ 115,867	$ (21,041)
Investment in PAA	70,042	64,626	—	—	—
Total assets	161,412	648,788	1,394,329	1,689,560	972,838
Long-term debt	27,000	282,061	626,376	676,703	431,983
Redeemable preferred stock	—	—	50,000	138,813	88,487
Stockholders' equity	105,509	254,852	137,140	40,619	69,170
Distributions from PAA(5)	29,063	31,553	30,134	29,472	—

(1) Relates to the sale of assets by PAA.

(2) Relates to losses resulting from unauthorized trading activity by a former employee of PAA.

(3) Amounts in 2002 and 1999 relate to public offerings by PAA. Amount in 2001 relates to sale of a portion of our interest in PAA and public offering by PAA. Amount in 1998 relates to formation of PAA.

(4) Amount for 2001 includes a $21.4 million deemed dividend and a $2.5 million cash payment related to the redemption and conversion of series F preferred stock in connection with our strategic restructuring. See Items 1 and 2 — "Business and Properties — Our June 2001 Strategic Restructuring".

(5) PAA was formed in 1998 and its first distributions were paid in 1999.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

The following information should be read in connection with the information contained in the consolidated financial statements and notes thereto included elsewhere in this report.

We are an independent energy company. We are principally engaged in the "midstream" activities of marketing, gathering, transporting, terminalling, and storage of oil through our equity ownership in PAA. PAA is a publicly traded master limited partnership actively engaged in the midstream energy markets. As of March 15, 2003 we owned 44% of the general partner of PAA and 12.4 million limited partner units of PAA, which represented approximately 24% aggregate ownership interest in PAA. We also participate in the "upstream" activities of acquiring, exploiting, developing, exploring for and producing oil through our wholly-owned subsidiary, Calumet Florida L.L.C., which has producing properties in the Sunniland Trend in south Florida.

The book value of our investment in PAA represents 43% of our total assets as of December 31, 2002 and the book value of our Florida oil properties represents 31%. As of December 31, 2002, the present value of our proved oil reserves was approximately $87.9 million (see "— Oil Production Operations"). We own 6.6 million common units, 1.3 million Class B common units and 4.5 million subordinated units of PAA. The closing price of publicly traded PAA common units, as reported on the New York Stock Exchange, was $24.40 on December 31, 2002. The Class B common units and the subordinated units are not publicly traded but do receive cash distributions from PAA. PAA's partnership agreement contains provisions which, upon the occurrence of certain future events, will result in the conversion of the subordinated units to common units. See — "Plains All American Pipeline, L.P. — PAA Cash Distributions". PAA's financial performance directly impacts our financial performance and the market value performance of PAA's limited partner interests directly impacts the value of our assets. As a result, we encourage you to review PAA's SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2002, to review and assess, among other things, PAA's financial performance and financial condition, PAA's business, operations, and competition, and risk factors associated with PAA's business.

Spin-off of Plains Exploration & Production Company

On December 18, 2002 we distributed 100% of the issued and outstanding shares of common stock of PXP, to the holders of record of our common stock as of the close of business on December 11, 2002. Each stockholder received one share of PXP common stock for each share of our common stock held. Prior to the spin-off, we borrowed $45 million under a new term loan facility and used a portion of the proceeds to make a $40 million cash capital contribution to PXP. In addition, prior to the spin-off we made a $7.2 million cash contribution to PXP and transferred to PXP certain assets and PXP assumed certain liabilities, primarily related to land, unproved oil and gas properties, office equipment and pension obligations.

We received a favorable private letter ruling from the IRS stating that, for United States federal income tax purposes, the distribution of our common stock qualified as a tax-free distribution under Section 355 of the Internal Revenue Code. The spin-off was completed to, among other things:

- allow us to obtain cost savings through improved access to capital markets for our midstream affiliate, PAA;
- allow PXP and us to focus corporate strategies and management teams for each business; and
- simplify our corporate structure.

In contemplation of the spin-off, under the terms of a Master Separation Agreement between us and PXP, on July 3, 2002 we contributed to PXP 100% of the capital stock of our wholly owned subsidiaries that own oil and gas properties in offshore California and Illinois. We also contributed to PXP $5.0 million in cash and $256.0 million of intercompany payables that PXP or its subsidiaries owed to us. On July 3, 2002 PXP issued $200 million of 8.75% Senior Subordinated Notes due 2012, or the 8.75% Notes, and entered into a $300 million revolving credit facility. PXP distributed the net proceeds of $195.3 million from the 8.75% notes and $116.7 million of initial borrowings under its credit facility to us. Of such distribution, we used:

- $287.0 million to redeem our 10.25% senior subordinated notes; and
- $25 million to repay and terminate our revolving credit facility.

As a result of the spin-off, the number of shares of our common stock into which shares of our Series D Preferred Stock, or Series D Preferred, is convertible increased from 932,000 shares to 1,671,416 shares as a result of the reduction in the conversion price from $25.00 per share of common stock to $13.94 per share. We have 46,600 shares of Series D Preferred outstanding with a stated value per share of $500 ($23.3 million aggregate stated value) that bears an annual dividend of $30.00 per share.

As a result of the spin-off the historical results of the operations of PXP are reflected in our financial statements as "discontinued operations". Except where noted, discussions in this Form 10-K with respect to oil and gas operations relate to our activities other than the discontinued operations.

General

Upstream Operations

We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration, exploitation and development activities are capitalized. Our revenues are derived from the sale of oil. We recognize revenues when our production is sold and title is transferred. Our revenues are highly dependent upon the prices of, and demand for oil. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and our levels of production are subject to wide fluctuations and depend on numerous factors beyond our control, including supply and demand, economic conditions, foreign imports, the actions of OPEC, political conditions in other oil-producing countries, and governmental regulation, legislation and policies. Under the SEC's full cost accounting rules, we review the carrying value of our proved oil and gas properties each quarter. These rules generally require that we price our future oil and gas production at the oil and gas prices in effect at the end of each fiscal quarter to determine a ceiling value of our properties. The rules require a write-down if our capitalized costs exceed the allowed "ceiling." We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will fluctuate in the near term. If oil prices decline in the future, write-downs of our oil and gas properties could occur. Write-downs required by these rules do not directly impact our cash flows from operating activities. Decreases in oil and gas prices have had, and will likely have in the future, an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow.

To manage our exposure to commodity price risks, we use various derivative instruments to hedge our exposure to oil sales price fluctuations. Our hedging arrangements provide us protection on the hedged volumes if oil prices decline below the prices at which these hedges are set. However, if oil prices increase, ceiling prices in our hedges may cause us to receive lower revenues on the hedged volumes than we would receive in the absence of hedges. Gains and losses from hedging transactions are recognized as revenues when the associated production is sold.

Our oil production expenses include salaries and benefits of personnel involved in production activities, electric costs, maintenance costs, production, ad valorem and severance taxes, and other costs necessary to operate our producing properties. Depletion of capitalized costs of producing oil and gas properties is provided using the units of production method based upon proved reserves. For the purposes of computing depletion, proved reserves are redetermined as of the end of each year and on an interim basis when deemed necessary. General and administrative expenses consist primarily of salaries and related benefits of administrative personnel, office rent, systems costs and other administrative costs.

Midstream Operations

We account for our investment in PAA using the equity method of accounting. We record equity in earnings of PAA based on our aggregate ownership interest, as adjusted for general partner incentive distributions. Equity in earnings for our general partner interest is based on our 44% share of 2% of PAA's net income plus the amount of the general partner incentive distribution. Equity in earnings for our limited partner units is based on our ownership percentage of limited partner units (25% at December 31, 2002) multiplied by 98% of PAA's net income less the general partner incentive distribution. Increased earnings attributable to the general partner incentive distributions will be somewhat offset because of our ownership of limited partner units. Cash distributions received from PAA are not reflected in earnings, but reduce our investment in PAA.

When PAA sells additional limited partner units and we do not purchase additional units, our ownership interest in PAA is reduced, creating an "implied sale" of a portion of our investment. We have recognized gains from PAA equity issuances representing the difference between our carrying cost and the fair value of the interest deemed sold.

Results of Operations

Our 2001 and 2000 income statements reflect the results of operations of PXP as discontinued operations. Also, as a result of the sale of a portion of our interest in PAA and the resulting change to the equity method of accounting for our investment in PAA in 2001, our income statement presentation for 2000 is not comparable to our income statement presentations for subsequent periods. The following table reflects our 2002 and 2001 income statements compared to a proforma income statement for 2000 adjusted to reflect PAA on the equity method of accounting. Our discussion of the results of operations will be based on the income statement presentation reflected herein.

	Year Ended December 31,		
	2002	2001	2000 ProForma
		(in thousands)	
Revenues			
Oil sales to Plains All American Pipeline, L.P.(1)	$ 18,662	$ 16,030	$ 8,990
Costs and Expenses			
Production expenses	6,536	7,397	5,912
Oil transportation costs	3,775	4,449	3,752
General and administrative	5,747	11,083	4,647
Depreciation, depletion and amortization	4,139	4,816	3,840
	20,197	27,745	18,151
Other Income (Expense)			
Equity in earnings of Plains All American Pipeline, L.P.	18,807	18,540	41,937
Gains on Plains All American Pipeline, L.P. unit transactions and public offerings	14,512	170,157	—
Loss on debt extinguishment	(10,319)	—	—
Interest expense	(5,866)	(8,974)	(14,523)
Interest and other income	239	(312)	(438)
	17,373	179,411	26,976
Income From Continuing Operations Before Income Taxes	15,838	167,696	17,815
Income tax expense	(6,106)	(67,072)	(5,628)
Income From Continuing Operations	9,732	100,624	12,187
Income from discontinued operations, net of tax	27,800	54,693	28,749
Income Before Cumulative Effect of Accounting Changes	37,532	155,317	40,936
Cumulative effect of accounting changes, net of tax benefit	—	(1,986)	(121)
Net Income	37,532	153,331	40,815
Cumulative preferred dividends	(1,400)	(27,245)	(14,725)
Income Available to Common Stockholders	$ 36,132	$126,086	$ 26,090

(1) Revenues for 2000 are pro forma to reflect the $0.20/Bbl marketing fee paid to PAA that was eliminated in consolidation.

The following table reflects the components of our oil and gas revenues from continuing operations and sets forth our revenues and costs and expenses from continuing operations on a BOE basis:

	Year Ended December 31,		
	2002	2001	2000 Proforma
Production (MBbls)	970	954	842
Sales (MBbls)	869	1,060	701
Average NYMEX price per Bbl	$26.15	$26.01	$30.25
Average hedge cost per Bbl	(0.71)	(1.11)	(9.37)
Average differential per Bbl(1)			
Quality	(3.97)	(9.77)	(5.70)
Transportation costs	(4.34)	(4.20)	(5.35)
Average realized price per Bbl	17.13	10.93	9.83
Production expenses per Bbl	(7.52)	(6.98)	(8.43)
Gross margin per Bbl	$ 9.61	$ 3.95	$ 1.40
DD&A per Bbl (oil & gas properties)	$ 3.73	$ 2.74	$ 1.56

(1) Oil transportation costs are included in costs and expenses in the consolidated statement of income.

(2) Prices in 2000 are proforma to include the $0.20/Bbl marketing fee paid to PAA that was eliminated in consolidation

Comparison of Year Ended December 31, 2002 to Year Ended December 31, 2001

In 2002, we reported net income of $37.5 million compared to net income of $153.3 million in 2001. Income from continuing operations was $9.7 million in 2002 compared to $100.6 million for 2001. Results for 2001 were affected by special items including $170.2 million of pre-tax gains related to the sale of a portion of our investment in PAA and PAA's equity offerings.

Oil revenues. Our oil revenues increased 17%, or $2.7 million, to $18.7 million for the year ended December 31, 2002 from $16.0 million for the year ended December 31, 2001. The increase was primarily due to higher realized oil prices that increased revenues by $6.8 million in 2002 versus 2001. This increase was offset by lower sales volumes that decreased revenues by $4.1 million in 2002.

We reported sales volumes from our Florida properties of 869 MBbls in 2002 compared to 1,060 MBbls in 2001. In accordance with SEC Staff Accounting Bulletin 101, or SAB 101, we reflect revenue from oil production in the period it is sold as opposed to when it is produced. Oil volumes increased 2% on an "as produced" basis, with production volumes of 970 MBbls in 2002 compared to 954 MBbls in 2001. The location of our Florida properties and the timing of the barges that transport the oil to market cause reported sales volumes to differ from production volumes. Actual timing of sales volumes is difficult to predict. The Florida oil is typically sold in shipments that range from approximately 110 MBbls to 140 MBbls and typically occurs every 30-50 days. In addition, our Florida properties consist of a relatively low number of higher volume wells and downtime due to equipment failures and other operational issues can cause production from this area to be volatile.

Our average realized price for oil excluding transportation costs increased 42%, or $6.34, to $21.47 per Bbl for the year ended December 31, 2002 from $15.13 per Bbl for the prior year. The increase is primarily attributable to an improvement in the location and quality differential to NYMEX, which was $3.97 per Bbl in 2002 versus $9.77 per Bbl in 2001. The average NYMEX oil price increased slightly to $26.15 per Bbl in 2002 compared to $26.01 per Bbl in 2001. Hedging had the effect of decreasing our average price per Bbl by $0.71 in 2002 and $1.11 in 2001.

Production expenses .Our production expenses decreased 12%, or $0.9 million, to $6.5 million for the year ended December 31, 2002 from $7.4 million for 2001 due to lower reported sales volumes. Unit production expenses for 2002 were $7.52 per Bbl compared to $6.98 in 2001. The per Bbl increase is primarily attributable to increased severance taxes due to higher oil prices in 2002 as well as the expiration of severance tax exemptions for several wells during the second quarter of 2002.

Oil Transportation Costs. Our oil transportation costs decreased 14% to $3.8 million in 2002 from $4.4 million in 2001 primarily reflecting lower sales volumes.

General and administrative expense. Our general and administrative, or G&A expense, decreased 49%, or $5.4 million, to $5.7 million for the year ended December 31, 2002 from $11.1 million for the prior year. The decrease primarily reflects the nonrecurring costs in 2001 related to our June 2001 strategic restructuring.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization, or DD&A expense decreased 15%, or $0.7 million, to $4.1 million for the year ended December 31, 2002 from $4.8 million for 2001. The decrease is primarily due to lower sales volumes in 2002 versus 2001. Our average DD&A rate for 2001 was $3.73 per Bbl compared to $2.74 per Bbl in 2001.

Equity in earnings of Plains All American Pipeline, L.P. Our equity in earnings of PAA increased slightly to $18.8 million for the year ended December 31, 2002 from $18.5 million for the 2001. Although PAA's net income increased from $44.2 million in 2001 to $65.3 million in 2002, our overall effective ownership was reduced to approximately 25% as of December 31, 2002 from 54% in January 2001. The reduced ownership interest is a result of the sale of a portion of our interest in June 2001 and PAA's subsequent equity offerings.

Gain on PAA units. In 2002 we recognized a noncash gain of $14.5 million due to the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from PAA's public equity offering.

The 2001 gain on PAA units of $170.2 million reflects: (i) $129.4 million in gains related to the sale of a portion of our investment in PAA in connection with our June 2001 strategic restructuring; (ii) $38.8 million of gains resulting from the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from PAA's 2001 public equity offerings, in which we did not participate; and (iii) a $2.0 million gain related to the vesting of certain unit grants.

Loss on debt extinguishment. We incurred a $10.3 million loss on debt extinguishment in 2002 primarily from the early retirement of $267.5 million of outstanding 10.25% senior subordinated notes. The loss consisted of a call premium of 3.4167% on the outstanding principal amount of the 10.25% notes, or $9.1 million, and $3.1 million of unamortized issue costs on the 10.25% notes and our revolving credit facility, net of $1.9 million of unamortized issue premium on the 10.25% notes.

Interest expense. Our interest expense decreased $3.1 million, to $5.9 million for the year ended December 31, 2002 from $9.0 million for 2001. The decrease is primarily due to the redemption of the 10.25% notes and the repayment of amounts outstanding under our revolving credit facility on July 3, 2002. From this date through early December 2002, when we borrowed $45 million under our term loan facility, we had no outstanding debt. Outstanding debt during this period was debt of PXP and accordingly, interest expense for this period is reflected in discontinued operations.

Income tax expense. Our income tax expense decreased $61.0 million to $6.1 million for the year ended December 31, 2002. The decrease was primarily due to lower pre-tax income from continuing operations. Pre-tax income from continuing operations was significantly higher in 2002 as a result of the gains related to the sale of the PAA interest.

Income from discontinued operations. Income from discontinued operations decreased from $54.7 million in 2001 to $27.8 million in 2002, primarily reflecting lower revenues due to lower realized prices partially offset by higher sales volumes, higher costs and expenses, and expenses related to a terminated public equity offering.

Comparison of Year Ended December 31, 2001 to Year Ended December 31, 2000

We reported net income of $155.3 million for the year ended December 31, 2001, compared to net income of $40.8 million for 2000. Income from continuing operations was $100.6 million in 2001 compared to $12.2 million for 2000. Results for 2001 were affected by special items including $170.2 million of pre-tax gains related to the sale of a portion of our investment in PAA in connection with our June 2001 strategic restructuring and PAA's equity offerings.

Oil revenues. Our revenues from oil sales increased by $7.0 million, from $9.0 million in 2000 to $16.0 million in 2001. The increase primarily reflects higher sales volumes that increased revenues by $5.4 million in 2001 versus 2000. Higher prices increased revenues by $1.6 million in 2001. Our oil sales volumes increased 51%, from 701 MBbls in 2000 to 1,060 MBbls in 2001. On an "as produced" basis, our oil volumes increased 13% from 842 MBbls in 2000 to 954 MBbls in 2001.

Our average realized price for oil excluding transportation costs decreased slightly, from $15.18 per Bbl. in 2000 to $15.13 per Bbl. in 2001. Hedges that we put into place in the latter part of 1999, when oil prices were considerably lower, reduced the 2000 realized price by $9.37 per Bbl.

Production expenses. Our production costs increased by $1.5 million, from $5.9 million for the year ended December 31, 2000 to $7.4 million for 2001. The 2001 increase was primarily attributable to increased volumes. Unit production expenses for 2001 were $6.98 per Bbl compared to $8.43 per Bbl in 2000. The decrease in unit costs was primarily attributable to lower repair and maintenance expense.

Oil Transportation Costs. Our oil transportation costs increased 16% to $4.4 million in 2001 from $3.8 million in 2000 primarily reflecting higher sales volumes, partially offset by lower costs.

General and administrative expense. Our G&A expense increased $6.5 million, from $4.6 million for the year ended December 31, 2000 to $11.1 million for 2001. Our 2001 G&A expense includes nonrecurring costs associated with our June 2001 strategic restructuring including noncash compensation cost primarily associated with the vesting of performance-based stock options in connection with our restructuring. G&A Expense for 2000 includes $1.1 million related to PAA's unauthorized trading loss.

Depreciation, depletion and amortization. Our DD&A expense increased $1.0 million, from $3.8 million for the year ended December 31, 2000 to $4.8 million for 2001. The increase reflects higher sales volumes and an increase in the per unit DD&A rate. Our average DD&A rate for 2000 was $1.56 per Bbl compared to $2.74 per Bbl in 2001.

Equity in earnings of PAA. Our equity in the earnings of PAA was $18.5 million for the year ended December 31, 2001 as compared to $41.9 million in 2000. The decrease was primarily attributable to the decrease in our ownership interest in 2001 as well as nonrecurring gains included in PAA's 2000 earnings. At December 31, 2000 our ownership interest in PAA was approximately 54%. Primarily as a result of PAA's two public unit offerings during 2001, and our June 2001 strategic restructuring, our ownership interest decreased to approximately 29% at December 31, 2001.

Gain on PAA units. The gain on PAA units reflects: (i) $129.4 million in gains related to the sale of a portion of our investment in PAA in connection with our June 2001 strategic restructuring; (ii) $38.8 million of gains resulting from the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from PAA's

2001 public equity offerings, in which we did not participate; and (iii) a $2.0 million gain related to the vesting of certain unit grants. No similar transactions occurred in 2000.

Interest expense. Our interest expense decreased by $5.5 million, from $14.5 million to $9.0 million for the year ended December 31, 2001 compared to 2000, reflecting lower bank debt and lower interest rates on borrowings under our revolving credit facility.

Income tax expense. Our income tax expense increased to $67.1 million for the year ended December 31, 2001 as compared to $5.6 million for 2000. The increase was primarily attributable to the gains on PAA units discussed above.

Income from discontinued operations. Income from discontinued operations increased from $28.7 million in 2000 to $54.7 million in 2001, primarily due to higher revenues, reflecting higher prices and sales volumes, partially offset by higher costs and expenses.

Cumulative effect of accounting change. The cumulative effect of accounting change recognized for the year ended December 31, 2001 is for the adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended. The amount in 2000 is for the adoption of SEC Staff Accounting Bulletin 101 "Revenue Recognition in Financial Statements".

Liquidity and Capital Resources

General

At December 31, 2002 we had negative working capital of $12.0 million. Cash generated from our upstream operations and PAA distributions are our primary sources of liquidity. We believe that we have sufficient liquid assets and cash from operations and PAA distributions to meet our short term and long-term normal recurring operating needs, debt service obligations, contingencies and anticipated capital expenditures.

If PAA could not, for any reason, make its minimum quarterly distribution payments on its limited partnership interests, this would impair our cash flows and our ability to meet our short and long-term cash needs. In addition, this would trigger our payment obligations under the value assurance agreements (for a description of the value assurance agreements, see "— Contingencies — Value Assurance Agreements"), which would compound the negative impact on our cash flows and our ability to meet our short and long-term cash needs. Thus, PAA's financial and operational performance directly affects our financial and operational performance. We encourage you to review PAA's SEC filings, including its Annual Report on Form 10-K for the year ended December 31, 2002.

PAA Cash Distributions

PAA's partnership agreement requires that it distribute 100% of available cash within 45 days after the end of each quarter to unitholders of record and to its general partner. Available cash is generally defined as all cash and cash equivalents on hand at the end of each quarter less reserves established by PAA's general partner for future requirements.

Distributions to holders of subordinated units are subject to the rights of holders of common units to receive minimum quarterly distribution, or MQD, of $0.45 per unit ($1.80 per unit on an annual basis). Common units accrue arrearages with respect to distributions for any quarter during the subordination period and subordinated units do not accrue any arrearages. The subordination period will end if PAA meets certain financial tests for three consecutive four-quarter periods. If PAA meets certain financial requirements, 25% of the subordinated units will convert in the fourth quarter of 2003 and the remainder will convert in the first quarter of 2004.

Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. If we request that PAA call a meeting of common unitholders to consider approval of the conversion of

Class B units into common units and the approval is not obtained within 120 days, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the common units.

PAA's general partner is entitled to receive incentive distributions if the amount distributed with respect to any quarter exceeds levels specified in its partnership agreement. Generally the general partner is entitled, without duplication, to 15% of amounts PAA distributes in excess of $0.450 per unit, 25% of the amounts PAA distributes in excess of $0.495 per unit and 50% of amounts PAA distributes in excess of $0.675 per unit.

Based on PAA's current annual distribution rate of $2.15 per unit, we would receive for 2003 an annual distribution from PAA of approximately $30.1 million, including $2.8 million for our general partner distribution (including $1.8 million for the general partner incentive distribution).

Cash distributions on PAA's outstanding common units, Class B common units and subordinated units and the portion of the distributions representing an excess over the MQD for 2002, 2001 and 2000 were as follows:

	Year					
	2002		2001		2000	
	Distribution	Excess over MQD	Distribution	Excess over MQD	Distribution	Excess over MQD
First Quarter	$0.5250	$0.0750	$0.4750	$0.0250	$0.4500 (1)	$ —
Second Quarter	0.5375	0.0875	0.5000	0.0500	0.4625	0.0125
Third Quarter	0.5375	0.0875	0.5125	0.0625	0.4625	0.0125
Fourth Quarter	0.5375	0.0875	0.5125	0.0625	0.4625	0.0125

(1) Reflects distributions to common and Class B common unitholders only. No distribution was declared or paid on the subordinated units owned by us in this period.

Financing Activities

In December 2002 we entered into a $45 million secured term loan facility with a group of banks. We used proceeds from the term loan and cash on hand to make a $40 million capital contribution and repay a $7.2 million note payable to PXP. The term loan is repayable in 10 quarterly installments of $4.5 million each commencing on February 28, 2003 with a final maturity of May 31, 2005. Amounts outstanding under the term loan bear an annual interest rate, at our election, equal to either the Base Rate (as defined in the agreement) plus 1.5%, or LIBOR plus 3%. The term loan requires that we maintain $5.0 million on deposit in a debt service reserve account with one of the lending banks.

To secure the term loan, we pledged 100% of the shares of stock of our subsidiaries and pledged 4,950,000 of our PAA common units. To the extent that the outstanding principal under the term loan exceeds the balance in the debt reserve account (as defined in the agreement) plus 50% of the fair market value of the pledged common units, we are required to repay the excess. The fair market value of the pledged units is determined based on the closing price of PAA common units on the New York Stock Exchange.

The term loan contains covenants that limit our ability, as well as the ability of our subsidiaries, to incur additional debt, make investments, create liens, enter into leases, sell assets, change the nature of our business or operations, guarantee other indebtedness, enter into certain types of hedge agreements, enter into take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, if an event of default exists, the term loan prohibits us from paying dividends or repurchasing or redeeming shares of any class of capital stock. The term loan requires us to maintain a minimum consolidated tangible net worth ($80 million at December 31, 2002) and a consolidated debt service coverage ratio (as defined in the agreement) of 1.0 to 1.0.

On July 3, 2002 PXP issued $200 million of 8.75% Senior Subordinated Notes due 2012, or the 8.75% Notes, and entered into a $300 million revolving credit facility. PXP distributed the net proceeds of $195.3 million from the 8.75% notes and $116.7 million of initial borrowings under its credit facility to us. Of such distribution, we used:

- $287.0 million to redeem our 10.25% senior subordinated notes; and
- $25 million to repay and terminate our revolving credit facility.

The $287.0 million used to redeem the 10.25% notes consisted of:

- $267.5 million principal amount outstanding;
- a $9.1 million call premium due as a result of the early redemption of the 10.25% notes; and
- $10.4 million in interest accrued and payable on the redemption date.

All of the outstanding 10.25% notes were redeemed and all guarantees with respect to the 10.25% notes were terminated. In connection with the redemption of the 10.25% notes and the termination of our credit facility, in the third quarter of 2002 we recognized a $10.3 million loss for debt extinguishment.

Cash Flows from Continuing Operations

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 7.6	$ 3.3	$ (43.6)
Investing activities	(7.3)	96.5	201.1
Financing activities	(235.4)	(90.7)	(228.7)

Operating Activities. Net cash provided by operating activities in 2002 totaled $7.6 million compared to $3.3 million in 2001. The net increase is primarily attributable to higher realized oil prices and increased sales volumes. Net cash provided by operating activities in 2001 totaled $3.3 million compared to net cash used in operating activities of $43.6 million in 2000. Net cash used in operating activities in 2000 is attributable to PAA's unauthorized trading losses.

Investing Activities. In 2002 net cash used in investing activities totaled $7.3 million. Additions to oil and gas properties and equipment used $5.9 million in cash, and we made capital contributions to PAA of $1.3 million to maintain our proportionate general partner share interest as a result of equity offerings by PAA. To maintain its 2% general partner interest, the general partner of PAA is required to make a capital contribution each time PAA has a new equity offering. In 2001 net cash provided by investing activities was $96.5 million. Additions to oil and gas properties and equipment used $6.0 million in cash, and we made capital contributions to PAA of $4.0 million to maintain our proportionate general partner share of equity offerings by PAA. These uses of cash were offset by $106.9 million in cash proceeds received as a result of our June 2001 strategic restructuring. During 2000 investing activities provided cash of $201.1 million. Proceeds from PAA asset sales of $224.3 million were offset primarily by expenditures of $12.2 million for oil pipeline, gathering and terminal costs and $8.2 million for upstream acquisition, exploration and development costs.

Financing activities. Cash used in financing activities in 2002 included a net reduction in long-term debt of $234.0 million, $5.2 million in proceeds from issuances of our common stock, and $1.4 million in preferred stock dividends. Cash used in financing activities in 2001 included a net reduction in long-term debt of $23.4 million, expenditures of $67.7 million for our repurchase of 2.8 million shares of our common stock, $9.2 million in proceeds from issuances of our common stock, and $8.7 million in preferred stock dividends. Cash used in financing activities in 2000 included a net reduction in long and short term debt of $157.5 million, expenditures of $23.6 million for our repurchase of 1.3 million shares of our common stock, $13.4 million in preferred stock dividends and $29.4 million in distributions to PAA unitholders.

Capital Expenditures

We have made and will continue to make capital expenditures with respect to our oil properties. We intend to make aggregate capital expenditures of approximately $3.7 million in 2003 for exploitation of our existing properties.

When PAA issues equity, the general partner is required to contribute cash to maintain its 2% general partner interest. In March 2003, PAA issued 2.6 million shares in a public equity offering. We were required to make a cash capital contribution to the general partner of PAA in the amount of $0.6 million for our 44% interest in the general partner. If PAA issues equity in the future, we will be required to make additional cash capital contributions.

We also have an active treasury share repurchase program. Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. Through December 31, 2001, we had repurchased a total of 4.1 million shares at a total cost of approximately $91.3 million. No shares were repurchased in 2002. We have resumed making purchases under the treasury share program and through March 15, 2003 we have repurchased an additional 142,700 shares at a total cost of $1.6 million. We intend to make additional repurchases in 2003 and expect to fund the purchases from cash flows.

Contractual Obligations

At December 31, 2002, the aggregate amounts of contractually obligated payment commitments for the next five years are as follows (in thousands):

	2003	2004	2005	2006	2007	Thereafter
Long-term debt	$18,000	$18,000	$9,000	$—	$—	$ —
Operating leases	22	23	23	6	—	—
	$18,022	$18,023	$9,023	$ 6	$—	$ —

Contingencies

In connection with our June 2001 strategic restructuring, we entered into value assurance agreements with the purchasers of the subordinated units, under the terms of which we will pay the purchasers an amount per fiscal year, payable on a quarterly basis, equal to $1.85 per unit less the actual amount distributed during that year. The value assurance agreements will expire upon the earlier of (a) the conversion of all of the subordinated units to common units or (b) June 8, 2006. In the first quarter of 2002 PAA paid a quarterly distribution of $0.5125 per unit ($2.05 annualized).

Also in connection with the June 2001 sale of a portion of our interest in PAA, we entered into a separation agreement with PAA whereby, among other things, (1) we agreed to indemnify PAA, its general partner, and its subsidiaries against (a) any claims related to the upstream business, whenever arising, and (b) any claims related to federal or state securities laws or the regulations of any self-regulatory authority, or other similar claims, resulting from alleged acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries occurring on or before June 8, 2001, and (2) PAA agreed to indemnify us and our subsidiaries against any claims related to the midstream business, whenever arising.

In connection with the reorganization and the spin-off we entered into certain agreements with PXP, including a master separation agreement; an intellectual property agreement; the Plains Exploration & Production transition services agreement; the Plains Resources transition services agreement; and a technical services agreement. See — Items 1 and 2. "Business and Properties — Spin-off Agreements".

Environmental Matters. As discussed in Items 1 and 2. "Business & Properties — Regulation — Environmental." as an owner or lessee and operator of oil and gas properties, we are subject to various federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. Typically when producing oil and gas assets are purchased, one assumes the obligation to plug and abandon wells that are part of such assets. We have established policies for continuing compliance with environmental laws and regulations. Also, we maintain insurance coverage for environmental matters, which we believe is customary in the industry, but we are not fully insured against all environmental risks. There can be no assurance that current or future local, state or federal rules and regulations will not require us to spend material amounts to comply with such rules and regulations.

Plugging, Abandonment and Remediation Obligations. Consistent with normal industry practices, our oil and gas leases require that, upon termination of economic production, the working interest owners plug and abandon non-producing wellbores, remove tanks, production equipment and flow lines and restore the wellsite. Typically when producing oil and gas assets are purchased, one assumes the obligation to plug and abandon wells that are part of such assets.

We have estimated that at December 31, 2002 the costs to perform these tasks will be approximately $9.0 million, net of salvage value. Effective January 1, 2003, upon adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations", we will record the fair value of the liabilities associated with our asset retirement obligations, See "Recent Accounting Pronouncements".

Other commitments and contingencies. As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and gas properties and the marketing, transportation, terminalling and storage of oil. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

As discussed in Item 3. "Legal Proceedings," in the ordinary course of business, we are a claimant and/or defendant in various legal proceedings. In particular, we are a party to a lawsuit (as a result of Stocker Resources, Inc.'s merger into us) regarding an electric services contract with Commonwealth Energy Corporation. In this lawsuit, we are seeking a declaratory judgment that we are entitled to terminate the contract and that Commonwealth has no basis for proceeding against a related $1.5 million performance bond. In a countersuit against us, Commonwealth is seeking unspecified damages. We intend to defend our rights vigorously in this matter. Under the spin-off agreements, PXP will indemnify us against this lawsuit. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

Operating risks and insurance coverage. Our operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including well blowouts, cratering, explosions, spills of oil, gas or well fluids, fires, pollution and releases of toxic gas, each of which could result in damage to or destruction of oil and gas wells, production facilities or other property, or injury to persons. Although we maintain insurance coverage considered to be customary in the industry, we are not fully insured against all risks, either because insurance is not available or because of high premium costs. The occurrence of a significant event that is not fully insured against could have a material adverse effect on our financial position. Our insurance does not cover every potential risk associated with operating our pipelines, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences.

PAA's Commitments and Contingencies

For a discussion of PAA's commitments and contingencies, we recommend you review PAA's Annual Report on Form 10-K for the year ended December 31, 2002, and other applicable SEC filings by PAA.

Material Related Party Transactions

Governance of PAA

We, along with Sable Investments, L.P. (which is owned by Mr. Flores, our Executive Chairman, and Mr. Raymond, our Chief Executive Officer), Kafu Holdings, L.P. (which is controlled by Kayne Anderson Capital Advisors, L.P. and Kayne Anderson Investment Management, Inc., of which Mr. Sinnott is Senior Vice President), and E-Holdings III, L.P. (which is controlled by EnCap Investments L.L.C. and of which Mr. Phillips is a managing director and principal) are parties to agreements governing Plains All American GP LLC, which is the general partner of Plains AAP, L.P., and Plains AAP, L.P., which is the general partner of PAA. These agreements govern the ongoing management of PAA.

In addition, the general partner of PAA is owned as follows:

Plains Resources	44.00%
Sable Investments, L.P.	20.00%
Kafu Holdings, L.P.	16.42%
E-Holdings, L.P.	9.00%
Others	10.58%
	100.00%

Also, each of we, Sable Investments, Kafu Holdings, and E-Holdings may appoint one member of the Plains All American GP LLC board of directors.

Value Assurance Agreements

We entered into a value assurance agreement with each of Sable Investments, Kafu Holdings and E-Holdings with respect to the subordinated units they acquired from us in our June 2001 strategic restructuring. The value assurance agreements require us to pay to them an amount per fiscal year, payable on a quarterly basis, equal to the difference between $1.85 per unit and the actual amount distributed during that period. The value assurance agreements will expire upon the earlier of the conversion of the subordinated units to common units, or June 8, 2006.

Our Relationship with PAA

We have ongoing relationships with PAA, including:

- a marketing agreement that provides that PAA will purchase all of our equity oil production at market prices for a fee of $.20 per barrel. In 2002, PAA paid us $22.7 million for such equity production and we paid PAA $0.2 million in marketing fees; and
- a separation agreement whereby, among other things, (1) we agreed to indemnify PAA, its general partner, and its subsidiaries against (a) any claims related to the upstream business, whenever arising, and (b) any claims related to federal or state securities laws or the regulations of any self-regulatory authority, or other similar claims, resulting from alleged acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries occurring on or before

June 8, 2001, and (2) PAA agreed to indemnify us and our subsidiaries against any claims related to the midstream business, whenever arising.

We are currently negotiating a new marketing agreement with PAA to, among other things, add a definitive term to the agreement and provide that PAA will use its reasonable best efforts to obtain the best price for our oil production. There can be no assurance, however, that we will enter into a new marketing agreement with PAA.

Spin-off Agreements

In connection with the spin-off of PXP, we entered into various agreements with PXP. For a discussion of these agreements, see Items 1 and 2. "Business and Properties — Spin-off Agreements".

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil operations and derivative instruments related to our hedging activities. PAA is the exclusive marketer/purchaser for all of our equity oil production. This concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that PAA may be affected by changes in economic, industry or other conditions. We do not believe the loss of PAA as the exclusive purchaser of our equity production would have a material adverse affect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions.

There are a limited number of alternative methods of transportation for our production. Substantially all of our oil production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil production which could have a negative impact on future results of operations or cash flows.

The contract counterparties for our derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better.

Critical Accounting Policies and Factors That May Affect Future Results

Based on the accounting policies which we have in place, certain factors may impact our future financial results. The most significant of these factors and their effect on certain of our accounting policies are discussed below.

Commodity pricing and risk management activities. Prices for oil have historically been volatile. Decreases in oil prices from current levels will adversely affect our revenues, results of operations, cash flows and proved reserves. If the industry experiences significant prolonged future price decreases, this could be materially adverse to our operations and our ability to fund planned capital expenditures.

Periodically, we enter into hedging arrangements relating to a portion of our oil production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations. Hedging instruments used are typically fixed price swaps and collars and purchased puts and calls. While the use of these types of hedging instruments limits our downside risk to adverse price movements, we are subject to a number of risks, including instances in which the benefit to revenues is limited when commodity prices increase. For a further discussion concerning our risks related to oil prices and our hedging programs, see "— Quantitative and Qualitative Disclosures about Market Risks".

Write-downs under full cost ceiling test rules. Under the SEC's full cost accounting rules we review the carrying value of our proved oil and gas properties each quarter. Under these rules, capitalized costs of proved oil and gas properties (net of accumulated depreciation, depletion and amortization, and deferred income taxes) may not exceed a "ceiling" equal to:

- the standardized measure (including, for this test only, the effect of any related hedging activities); plus
- the lower of cost or fair value of unproved properties not included in the costs being amortized (net of related tax effects).

These rules generally require that we price our future oil production at the prices in effect at the end of each fiscal quarter and require a write-down if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil prices, it is likely that our estimate of discounted future net revenues from proved oil reserves will change in the near term. If oil prices decline in the future, even if only for a short period of time, write-downs of our oil and gas properties could occur. Write-downs required by these rules do not directly impact our cash flows from operating activities.

Based on the book value of our proved oil and gas properties (including related deferred income taxes) and our proved reserve reports as of December 31, 2002, we believe that we would have a write-down under the full cost ceiling test rules at a net realized price for our oil production of approximately $17.50 per barrel. Based on an estimated oil differential for 2003 of $9.00 — $9.50 per barrel, we would have a write-down at a NYMEX oil index price of $26.50 — $27.00 per barrel.

Oil and gas reserves. The proved reserve information included herein were based on estimates prepared by outside engineering firms. Estimates prepared by others may be higher or lower than these estimates.

Estimates of proved reserves may be different from the actual quantities of oil and gas recovered because such estimates depend on many assumptions and are based on operating conditions and results at the time the estimate is made. The actual results of drilling and testing, as well as changes in production rates and recovery factors, can vary significantly from those assumed in the preparation of reserve estimates. As a result, such factors have historically, and can in the future, cause significant upward and downward revisions to proved reserve estimates.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with SEC requirements, we base the estimated discounted future net revenues from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

All of our reserve base is comprised of oil properties that are sensitive to oil price volatility. Historically, we have experienced significant upward and downward revisions to our reserves volumes and values as a result of changes in year-end oil and gas prices and the corresponding adjustment to the projected economic life of such properties. Prices for oil and gas are likely to continue to be volatile, resulting in future downward and upward revisions to our reserve base.

Our rate of recording DD&A is dependent upon our estimate of proved reserves including future development and abandonment costs as well as our level of capital spending. If the estimates of proved reserves decline, the rate at which we record DD&A expense increases, reducing our net income. This decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the "ceiling" test discussed above. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expense. We are unable to predict changes in future development costs as such costs are dependent on the success of our exploitation and development program, as well as future economic conditions.

PAA's Critical Accounting Policies. For a discussion of PAA's critical accounting policies, we recommend you review PAA's Annual Report on Form 10-K for the year ended December 31, 2002, and other applicable SEC filings by PAA.

Recent Accounting Pronouncements

Statement of Accounting Standards, or SFAS, No. 143, "Accounting for Asset Retirement Obligations" becomes effective January 1, 2003. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Each period the liability is accreted to its then present value, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all historical periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and these costs have been amortized as a component of our depletion expense.

We have completed our assessment of SFAS No. 143 and we estimate that at January 1, 2003 the present value of our future Asset Retirement Obligation ("ARO") for oil and gas properties and equipment is approximately $2.6 million. We estimate that the cumulative effect of our adoption of SFAS No. 143 and the change in accounting principle will result in an increase in net income during the first quarter of 2003 of $1.5 million (reflecting a $2.9 million decrease in accumulated DD&A, partially offset by $1.3 million in accretion expense), $0.9 million net of taxes. We estimate that we will record a liability of $2.6 million and an asset of $1.2 million in connection with the adoption of SFAS 143. There will be no impact on our cash flows as a result of adopting SFAS No. 143.

In April 2002, SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections," was issued. SFAS 145 rescinds SFAS 4 and SFAS 64 related to classification of gains and losses on debt extinguishment such that most debt extinguishment gains and losses will no longer be classified as extraordinary. SFAS 145 also amends SFAS 13 with respect to sales-leaseback transactions. The provisions of SFAS 145 with respect to sales-leaseback transactions have no effect on our financial statements. As a result of the provisions of SFAS 145 with respect to debt extinguishments, the $15.1 million of debt extinguishment costs related to the refinancing of certain of PAA's debt instruments in 2000 are not classified as an extraordinary item in our statement of income.

In July 2002 SFAS No. 146, "Accounting For Costs Associated with Exit or Disposal Activities" was issued. SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002 and does not require previously issued financial statements to be restated. We will account for exit or disposal activities initiated after December 31, 2002 in accordance with the provisions of SFAS 146.

In December 2002, SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FASB Statement No. 123" was issued. SFAS 148 amends SFAS 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The provisions of SFAS 148 are effective for financial statements for fiscal years ending after December 15, 2002. SFAS 148 does not change the provisions of SFAS 123 that permit entities to continue to apply the intrinsic value method of Accounting Principles Bulletin No. 25, "Accounting for Stock Issued to Employees". We will continue to account for stock-based compensation on accordance with the provisions of APB No. 25. We will provide the disclosures required by SFAS 148 in our financial statements.

In November 2002 FASB interpretation 45, or FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others" was issued. FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of FIN 45. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. The disclosures required by FIN 45 are included in this Form 10-K.

In January 2003 FASB Interpretation 46, or FIN 46, "Consolidation of Variable Interest Entities" was issued. FIN 46 identifies certain off-balance sheet arrangements that meet the definition of a variable interest entity (VIE). The primary beneficiary of a VIE is the party that is exposed to the majority of the risks and/or returns of the VIE. In future accounting periods, the primary beneficiary will be required to consolidate the VIE. In addition, more extensive disclosure requirements apply to the primary beneficiary, as well as other significant investors. We do not believe we participate in any arrangement that would be subject to the provisions of FIN 46.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risks*

We are exposed to various market risks, including volatility in oil commodity prices and interest rates. To manage our exposure, we monitor current economic conditions and our expectations of future commodity prices and interest rates when making decisions with respect to risk management. We do not enter into derivative transactions for speculative trading purposes.

Derivative instruments are accounted for in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138, or SFAS 133. All derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a fair value hedge, cash flow hedge or foreign currency hedge. Currently, we use only cash flow hedges and the remaining discussion will relate exclusively to this type of derivative instrument. If the derivative qualifies for hedge accounting, the gain or loss on the derivative is deferred in accumulated Other Comprehensive Income, or OCI, a component of our stockholders' equity, to the extent the hedge is effective.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. Hedge accounting is discontinued prospectively when a hedge instrument becomes ineffective. Gains and losses deferred in OCI related to cash flow hedges that become ineffective remain unchanged until the related product is delivered. If it is determined that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. Hedge effectiveness is measured on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items. No amounts were excluded from the computation of hedge effectiveness. At December 31, 2002, all open positions qualified for hedge accounting.

We utilize various derivative instruments to hedge our exposure to price fluctuations on oil sales. The derivative instruments consist primarily of cash-settled oil option and swap contracts entered into with financial institutions.

At December 31, 2002 OCI consisted of unrealized losses of: (i) $0.4 million ($0.3 million, net of tax) on our oil hedging instruments, (ii) $3.7 million ($2.3 million, net of tax) related to our equity in the OCI loss of PAA, and (iii) $0.5 million ($0.3 million, net of tax) related to pension liabilities. At December 31, 2002, the liability related to our open oil hedging instruments was included in current liabilities ($0.4 million), and deferred income taxes (a tax benefit of $0.2 million)

During 2002 oil sales revenues were reduced by $0.6 million for non-cash expense related to the amortization of option premiums. As of December 31, 2002, $0.4 million ($0.2 million, net of tax) of deferred net losses on our oil hedging instruments recorded in OCI are expected to be reclassified to earnings during 2003.

Commodity Price Risk. At March 1, 2003, we had the following open oil hedge positions:

	Barrels Per Day	
	2003	*2004*
Swaps		
Average price $26.10/bbl	1,500	—
Average price $24.07/bbl	—	1,000

Assuming our fourth quarter 2002 sales volumes are held constant in subsequent periods, these positions result in our hedging approximately 61% and 41% of oil sales in 2003 and 2004, respectively. Location and quality differentials attributable to our properties are not included in the foregoing prices. Because of the quality and location of our oil production, these adjustments will reduce our net price per barrel.

The agreements provide for monthly cash settlement based on the differential between the agreement price and the actual NYMEX price. Gains or losses are recognized in the month of related production and are included in oil sales revenues. Such contracts resulted in a reduction of revenues of $0.6 million, $1.2 million and $6.6 million for the years ended December 31, 2002, 2001 and 2000, respectively.

The fair value of outstanding oil derivative commodity instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	December 31,			
	2002		2001	
	Fair Value	Effect of 10% Price Decrease	Fair Value	Effect of 10% Price Decrease
Swaps and options contracts	$(0.4)	$1.9	$1.5	$0.7

The fair value of the swaps and option contracts are estimated based on quoted prices from independent reporting services compared to the contract price of the swap and approximate the gain or loss that would have been realized if the contracts had been closed out at year end. All hedge positions offset physical positions exposed to the cash market. None of these offsetting physical positions are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month oil prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

In the fourth quarter of 2001 we terminated our open oil put options with Enron Risk Management Corp. and charged earnings for $0.9 million, representing unamortized premiums for such options. The contract counterparties for our current derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better.

Our management intends to continue to maintain hedging arrangements for a significant portion of our production. These contracts may expose us to the risk of financial loss in certain circumstances. Our hedging arrangements provide us protection on the hedged volumes if oil prices decline below the prices at which these hedges are set, but ceiling prices in our hedges may cause us to receive less revenue on the hedged volumes than we would receive in the absence of hedges.

Interest Rate Risk. Our debt instruments are sensitive to market fluctuations in interest rates. At December 31, 2002 we had $45.0 million outstanding under our credit facility, repayable $18.0 million in 2003, $18.0 million in 2004 and $9.0 million in 2005. Our credit facility bears interest at a base rate (as defined) or LIBOR plus the applicable margin (4.4% at December 31, 2002). The carrying value of our credit facility debt approximates fair value because interest rates are variable, based on prevailing market rates.

Item 8. *Financial Statements and Supplementary Data*

The information required here is included in this report as set forth in the "Index to Financial Statements" on page F-1.

The financial statements, including the notes thereto, of PAA are incorporated herein by reference to pages F-1 through F-37 of PAA's Annual Report on Form 10-K for the year ended December 31, 2002 (as may be amended from time to time). The PAA financial statements were prepared by PAA.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

Information regarding our directors and executive officers will be included in the proxy statement for the 2003 annual meeting of stockholders to be filed within 120 days after December 31, 2002, and is incorporated by reference to this report.

We have provided summary information with respect to our directors and executive officers following Item 4 in Part I of this report.

Item 11. *Executive Compensation*

Information regarding executive compensation will be included in the proxy statement and is incorporated by reference to this report.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Information regarding beneficial ownership and related stockholder matters will be included in the proxy statement and is incorporated by reference to this report.

Item 13. *Certain Relationships and Related Transactions*

Information regarding certain relationships and related transactions will be included in the proxy statement and is incorporated by reference to this report.

Item 14. ***Controls and Procedures***

Within 90 days before the date of this report on Form 10-K, under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-14(c) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information we are required to disclose in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of such evaluation.

PART IV

Item 15. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

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

See "Index to Consolidated Financial Statements" set forth on Page F-1.

The financial statements, including the notes thereto, of PAA are incorporated herein by reference to pages F-1 through F-37 of PAA's Annual Report on Form 10-K for the year ended December 31, 2002 (as may be amended from time to time). The PAA financial statements were prepared by PAA.

(a) (3) Exhibits

2.1	Stock Purchase Agreement dated as of March 15, 1998, among Plains Resources Inc., Plains All American Inc. and Wingfoot Ventures Seven Inc. (incorporated by reference to Exhibit 2(b) to the Company's Annual Report on Form 10-K for the year ended December 31, 1997).
3.1	Second Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3(a) to the Company's Annual Report on Form 10-K for the year ended December 31, 1995).
3.2	Bylaws of the Company
3.3	Certificate of Designation, Preference and Rights of Series D Cumulative Convertible Preferred Stock (incorporated by reference to Exhibit 3(c) to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 1997).
3.4	First Amendment to the Plains Resources Inc. Bylaws (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4 to the Company's Form S-1 Registration Statement (Reg. No. 33-33986)).
10.1	The Company's 1992 Stock Incentive Plan (incorporated by reference to Exhibit 4.3 to the Company's Form S-8 Registration Statement (Reg. No. 33-48610)).
10.2	First Amendment to the Company's 1992 Stock Incentive Plan (incorporated by reference to Exhibit 10(n) to the Company's Annual Report on Form 10-K for the year ended December 31, 1996).
10.3	Second Amendment to the Company's 1992 Stock Incentive Plan (incorporated by reference to Exhibit 10(b) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1997).
10.4	Third Amendment to Plains Resources Inc. 1992 Stock Incentive Plan dated May 21, 1998 (incorporated by reference to Exhibit 10(aa) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998).
10.5	The Company's 1996 Stock Incentive Plan (incorporated by reference to Exhibit 4 to the Company's Form S-8 Registration Statement (Reg. No. 333-06191)).
10.6	First Amendment to Plains Resources Inc. 1996 Stock Incentive Plan dated May 21, 1998 (incorporated by reference to Exhibit 10(z) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 1998)
10.7	Second Amendment to Plains Resources 1996 Stock Incentive Plan dated May 20, 1999 (incorporated by reference to Exhibit 10(q) to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 1999).
10.8	Third Amendment to Plains Resources 1996 Stock Incentive Plan dated June 7, 2000(incorporated by reference to Exhibit 10.23 to the Company's Annual Report on Form 10-K for the Year Ended December 31, 2000).
10.9	Forms of Officer Stock Option Agreement (incorporated by reference to Exhibits 4.1 and 4.2 to the Company's Form S-8 Registration Statement (Registration No. 333-45562).

10.10 Contribution, Conveyance and Assumption Agreement among Plains All American Pipeline, L.P. and certain other parties dated as of November 23, 1998 (incorporated by reference to Exhibit 10.03 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.11 Crude Oil Marketing Agreement among Plains Resources Inc., Plains Illinois Inc., Stocker Resources, L.P., Calumet Florida, Inc. and Plains Marketing, L.P. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.07 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.12 First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the Year Ended December 31, 1998 for Plains All American Pipeline, L.P.).

10.13 Performance Stock Option Agreement dated as of May 8, 2001 between Plains Resources Inc. and James C. Flores (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.14 Separation Agreement dated as of June 8, 2001 by and among Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.), Plains All American GP LLC, Plains AAP, LP and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.15 Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001, by and between Plains Resources Inc., Plains Holdings Inc. (formerly known as Plains All American Inc.) and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.16 Value Assurance Agreement dated as of June 8, 2001 by and among Plains Resources Inc. and Sable Holdings L.P. and schedule of other Value Assurance Agreements substantially identical thereto (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.17 Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, between Plains Holdings Inc. (formerly known as Plains All American Inc.), Plains AAP, LP and Plains All American GP LLC. (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.18 Registration Rights Agreement dated as of May 8, 2001, among Plains Resources Inc. and James C. Flores. (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.19 Registration Rights Agreement dated as of June 8, 2001, among Plains Resources Inc., Strome Hedgecap Fund L.P., Strome Series Fund 1, Strome Series Fund 2 and Mark E. Strome. (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.20 Registration Rights Agreement dated as of June 8, 2001, among Plains All American Pipeline, L.P., Sable Holdings, L.P., E-Holdings III, L.P., KAFU Holdings, LP, PAA Management, L.P., Mark E. Strome, Strome Hedgecap Fund, L.P., John T. Raymond, and Plains Holdings Inc. (formerly known as Plains All American Inc.) (incorporated by reference to Exhibit 10.9 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.21 Registration Rights Agreement dated as of June 8, 2001, among Plains Resources Inc. and EnCap Energy Capital Fund III, L.P., EnCap Energy Capital Fund III-B, L.P., BOCP Energy Partners, L.P. and Energy Capital Investment Company PLC. (incorporated by reference to Exhibit 10.10 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.22 Registration Rights Agreement dated as of June 8, 2001, among Plains Resources Inc. and Kayne Anderson Capital Advisors, L.P. (incorporated by reference to Exhibit 10.11 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.23 Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated as of June 8, 2001. (incorporated by reference to Exhibit 10.12 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.24 Amended and Restated Limited Partnership Agreement of Plains AAP, L.P, dated June 8, 2001. (incorporated by reference to Exhibit 10.13 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.25 Plains Resources Inc. 2001 Stock Incentive Plan. (incorporated by reference to Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q for the three months ended June 30, 2001).

10.26 Value Assurance Agreement, dated as of August 17, 2001, by and among Plains Resources Inc. and First Union Investors, Inc. (incorporated by reference to Exhibit 10.34 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

10.27 Combination Incentive Stock Option and Nonqualified Stock Option Agreement, dated as of June 7, 2001, between John T. Raymond and Plains Resources Inc. (incorporated by reference to Exhibit 10.36 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

10.28 Performance Stock Option Agreement, dated as of June 7, 2001, between John T. Raymond and Plains Resources Inc. (incorporated by reference to Exhibit 10.37 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001).

10.29 Secured Term Loan Agreement dated as of December 6, 2002, by and among the Company, Bank of Montreal as Administrative Agent, Bank One, NA, as Syndication Agent, Wells Fargo Bank Texas, NA, as Collateral Agent and Documentation Agent, and the Lenders named therein (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on January 2, 2003).

10.30 Amended and Restated Employment Agreement, dated as of September 19, 2002, by and between James C. Flores and the Company (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 2002).

10.31 Amended and Restated Employment Agreement, dated as of September 19, 2002, by and between John T. Raymond and the Company (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 2002).

10.32* Form of Officer Restricted Stock Award Agreement.

10.33* Form of Restricted Stock Unit Agreement.

10.34* Form of Incentive Stock Option Agreement.

10.35* Form of Non-Qualified Stock Option Agreement.

10.36 Master Separation Agreement dated July 3, 2002 between PXP and the Company (incorporated by reference to Exhibit 10.1 to PXP's Amendment No. 1 to Form S-1 filed on August 28, 2002).

10.37 Plains Exploration & Production Company Transition Services Agreement dated July 3, 2002 between PXP and the Company (incorporated by reference to Exhibit 10.2 to PXP's Amendment No. 1 to Form S-1 filed on August 28, 2002).

10.38 Extension of Term of Plains Exploration & Production Company Transition Services Agreement, dated as of December 18, 2002, between PXP and the Company (incorporated by reference to Exhibit 10.3 to PXP's Registration Statement on Form S-4 filed on February 12, 2003).

10.39 Plains Resources Inc. Transition Services Agreement dated July 3, 2002 between the Company and PXP (incorporated by reference to Exhibit 10.3 to PXP's Amendment No. 1 to Form S-1 filed on August 28, 2002).

10.40 Second Amended and Restated Tax Allocation Agreement dated November 20, 2002 between PXP and the Company (incorporated by reference to Exhibit 10.4 to PXP's Amendment No. 1 to Form 10 filed on November 21, 2002).

10.41	Technical Services Agreement dated July 3, 2002 between PXP and the Company (incorporated by reference to Exhibit 10.5 to PXP's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.42	Intellectual Property Agreement dated July 3, 2002 between PXP and the Company (incorporated by reference to Exhibit 10.6 to PXP's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.43	Employee Matters Agreement dated July 3, 2002 between PXP and the Company (incorporated by reference to Exhibit 10.7 to PXP's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.44	Amendment No. 1 to Employee Matters Agreement, dated as of September 18, 2002, between the Company and PXP (incorporated by reference to Exhibit 10.22 to PXP's Amendment No. 2 to Form S-1 filed on October 4, 2002).
10.45	Amendment No. 1 to Master Separation Agreement, dated as of November 20, 2002, between the Company and PXP (incorporated by reference to Exhibit 10.24 to PXP's Amendment No. 1 to Form 10 filed on November 21, 2002).
10.46	Amendment No. 2 to Employee Matters Agreement, dated as of November 20, 2002, between the Company and PXP (incorporated by reference to Exhibit 10.25 to PXP's Amendment No. 1 to Form 10 filed on November 21, 2002).
10.47	Amendment No. 3 to Employee Matters Agreement, dated as of December 2, 2002, between PXP and the Company (incorporated by reference to Exhibit 10.23 to PXP's Registration Statement on Form S-4 filed on February 12, 2003).
10.48	First Amendment to Plains Resources Inc. 2001 Stock Incentive Plan (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the three months ended September 30, 2002).
10.49*	Second Amendment to Plains Resources Inc. 2001 Stock Incentive Plan.
21.1*	Subsidiaries of the Company
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of PricewaterhouseCoopers LLP.
23.3*	Consent of Netherland, Sewell and Associates, Inc.
99.1	The financial statements of Plains All American Pipeline, L.P. included on pages F-1 through F-37 of PAA's Annual Report on Form 10-K for the year ended December 31, 2002.
99.2*	Chief Executive Officer Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.3*	Chief Financial Officer Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

(b) Reports on Form 8-K

A Current Report on Form 8-K was filed on February 27, 2003 with respect to the Company's press release reporting 2002 earnings and December 31, 2002 oil and gas reserve information.

A Current Report on Form 8-K was filed on February 27, 2003 with respect to current estimates of certain results for 2003.

A Current Report on Form 8-K was filed on January 2, 2003 with respect to the completion of the spin off and the Company's new term loan facility.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS RESOURCES INC.

By: /s/ STEPHEN A. THORINGTON

Stephen A. Thorington
Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)

Date: March 28, 2003

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
By: /s/ JOHN T. RAYMOND John T. Raymond	Chief Executive Officer and President (Principal Executive Officer)	March 28, 2003
By: /s/ JAMES C. FLORES James C. Flores	Executive Chairman of the Board	March 28, 2003
By: /s/ WILLIAM M. HITCHCOCK William M. Hitchcock	Director	March 28, 2003
By: /s/ D. MARTIN PHILLIPS D. Martin Phillips	Director	March 28, 2003
By: Robert V. Sinnott	Director	
By: /s/ J. TAFT SYMONDS J. Taft Symonds	Director	March 28, 2003
By: /s/ STEPHEN A. THORINGTON Stephen A. Thorington	Executive Vice President and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	March 28, 2003

CERTIFICATION

I, John T. Raymond, Chief Executive Officer of Plains Resources Inc., certify that:

1. I have reviewed this annual report on Form 10-K of Plains Resources Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a. designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b. evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a. all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ John T. Raymond

Name: John T. Raymond
Title: Chief Executive Officer and President

Date: March 28, 2003

CERTIFICATION

I, Stephen A. Thorington, Chief Financial Officer of Plains Resources Inc., certify that:

1. I have reviewed this annual report on Form 10-K of Plains Resources Inc.;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and have:

a. designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

b. evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c. presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

a. all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

/s/ Stephen A. Thorington

Name: Stephen A. Thorington
Title: Executive Vice President and
Chief Financial Officer

Date: March 28, 2003

PLAINS RESOURCES INC.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Financial statements of our equity investment, Plains All American Pipeline, L.P., are included in this report as Exhibit 99.1.

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and
Stockholders of Plains Resources Inc.

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Plains Resources Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 4 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities in connection with its adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
March 24, 2003

PLAINS RESOURCES INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	(in thousands)	
ASSETS		
Current Assets		
Cash and cash equivalents	$ 8,807	$ 1,179
Accounts receivable — Plains All American Pipeline, L.P.	—	13,726
Other accounts receivable	1,589	6,313
Commodity hedging contracts and other derivatives	—	23,257
Inventory	2,305	6,721
Other current assets	1,515	1,527
	14,216	52,723
Property and Equipment, at cost		
Oil and gas properties — full cost method		
Subject to amortization	349,517	900,898
Not subject to amortization	—	40,506
Other property and equipment	27	4,003
	349,544	945,407
Less allowance for depreciation, depletion and amortization	(299,214)	(437,982)
	50,330	507,425
Investment in Plains All American Pipeline, L.P.	70,042	64,626
Other Assets		
Deferred income taxes	16,957	—
Other	9,867	24,014
	26,824	24,014
	$ 161,412	$ 648,788
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and other current liabilities	$ 1,361	$ 30,136
Taxes payable	1,878	4,196
Royalties payable	348	9,042
Interest payable	78	8,286
Current maturities of long-term debt	18,000	511
Other current liabilities	4,522	10,521
	26,187	62,692
Long-Term Debt		
Bank debt	27,000	11,500
Subordinated debt	—	269,539
Other	—	1,022
	27,000	282,061
Other Long-Term Liabilities	2,716	4,889
Deferred Income Taxes	—	44,294
Commitments and Contingencies (Notes 16 and 17)		
Stockholders' Equity		
Series D Cumulative Convertible Preferred Stock, $1.00 par value, 46,600 shares authorized, issued and outstanding, at stated value	23,300	23,300
Common Stock, $0.10 par value, 50,000,000 shares authorized; 28,048,378 and 27,677,411 shares issued at December 31, 2002 and 2001, respectively	2,806	2,768
Additional paid-in capital	273,162	268,520
Retained earnings (deficit)	(103,882)	37,676
Accumulated other comprehensive income	(2,862)	13,930
Treasury stock, at cost	(87,015)	(91,342)
	105,509	254,852
	$ 161,412	$ 648,788

See notes to consolidated financial statements.

PLAINS RESOURCES INC.

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2002	2001	2000
	(in thousands, except per share data)		
Revenues			
Oil sales to Plains All American Pipeline, L.P.	$ 18,662	$ 16,030	$ 10,643
Marketing, transportation, storage and terminalling	—	—	6,425,644
Gain on sale of assets	—	—	48,188
	18,662	16,030	6,484,475
Costs and Expenses			
Production expenses	6,536	7,397	5,912
Oil transportation expenses	3,775	4,449	3,752
General and administrative	5,747	11,083	44,468
Marketing, transportation, storage and terminalling	—	—	6,292,615
Unauthorized trading losses and related expenses	—	—	7,963
Depreciation, depletion and amortization	4,139	4,816	28,362
	20,197	27,745	6,383,072
Other Income (Expense)			
Equity in earnings of Plains All American Pipeline, L.P.	18,807	18,540	—
Gains on Plains All American Pipeline, L.P. unit transactions and public offerings	14,512	170,157	—
Loss on debt extinguishment	(10,319)	—	(15,148)
Interest expense	(5,866)	(8,974)	(39,943)
Interest and other income (expense)	239	(312)	7,068
	17,373	179,411	(48,023)
Income From Continuing Operations Before Income Taxes and Minority Interest	15,838	167,696	53,380
Minority interest in Plains All American Pipeline, L.P.	—	—	(35,565)
Income tax expense	(6,106)	(67,072)	(5,628)
Income From Continuing Operations	9,732	100,624	12,187
Income from discontinued operations, net of tax	27,800	54,693	28,749
Income Before Cumulative Effect of Accounting Changes	37,532	155,317	40,936
Cumulative effect of accounting changes, net of tax benefit	—	(1,986)	(121)
Net Income	37,532	153,331	40,815
Cumulative preferred dividends	(1,400)	(27,245)	(14,725)
Net Income Available to Common Stockholders	$ 36,132	$126,086	$ 26,090
Basic Earnings Per Share			
Continuing operations	$ 0.35	$ 3.48	$ (0.14)
Discontinued operations	1.16	2.59	$ 1.61
Change in accounting policy	—	(0.09)	$ (0.01)
	$ 1.51	$ 5.98	$ 1.46
Diluted Earnings Per Share			
Continuing operations	$ 0.34	$ 2.81	$ (0.14)
Discontinued operations	1.14	2.01	1.54
Change in accounting policy	—	(0.07)	(0.01)
	$ 1.48	$ 4.75	$ 1.39

See notes to consolidated financial statements.

PLAINS RESOURCES INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
Cash Flows from Operating Activities			
Net income	$ 37,532	$ 153,331	$ 40,815
Items not affecting cash flows from continuing operating activities			
Earnings from discontinued operations, net of taxes	(27,800)	(54,693)	(28,749)
Depreciation, depletion and amortization	4,139	4,816	28,362
Equity in earnings of Plains All American Pipeline, L.P.	(18,807)	(18,540)	—
Distributions received from Plains All American Pipeline, L.P.	29,063	31,553	—
Noncash gains	(14,512)	(170,157)	(48,188)
Minority interest in Plains All American Pipeline, L.P.	—	—	35,566
Deferred income taxes	7,069	63,139	6,963
Cumulative effect of adoption of SFAS 133	—	1,986	—
Change in derivative fair value	—	172	—
Noncash compensation expense	1,778	4,514	2,682
Allowance for doubtful accounts	—	—	5,000
Other noncash items	1,585	630	10,925
Change in assets and liabilities from operating activities			
Accounts receivable and other	2,338	11,826	95,054
Inventory	240	1,724	(13,782)
Accounts payable and other	(14,987)	(26,981)	(161,573)
Pipeline linefill	—	—	(16,679)
Net cash provided by (used in) continuing activities	7,638	3,320	(43,604)
Net cash provided by (used in) discontinued activities	82,097	116,808	79,464
Net cash provided by (used in) operating activities	89,735	120,128	35,860
Cash Flows from Investing Activities			
Acquisition, exploration and developments costs	(5,860)	(6,032)	(8,221)
Additions to other property and assets	(64)	(434)	(2,767)
Plains All American Pipeline, L.P. acquisitions and assets	—	—	(12,219)
Proceeds from the sale of Plains All American Pipeline, L.P. units	—	106,941	—
Investment in Plains All American Pipeline, L.P.	(1,334)	(3,978)	—
Proceeds from asset sales	—	—	224,261
Net cash provided by (used in) continuing activities	(7,258)	96,497	201,054
Net cash provided by (used in) discontinued activities	(64,158)	(125,880)	(70,871)
Net cash provided by (used in) investing activities	(71,416)	(29,383)	130,183
Cash Flows from Financing Activities			
Proceeds from long-term debt	45,000	204,900	1,698,575
Proceeds from short-term debt	—	—	51,300
Proceeds from sale of common stock	5,210	9,169	2,301
Purchase of senior subordinated notes	—	(7,550)	—
Principal payments of long-term debt	(278,950)	(220,700)	(1,798,675)
Principal payments of short-term debt	—	—	(108,719)
Purchase of common stock	—	(67,729)	(23,613)
Costs incurred in connection with financing arrangements	(632)	—	(6,748)
Increase in restricted cash	(5,000)	—	—
Preferred stock dividends	(1,400)	(8,698)	(13,409)
Distributions to Plains All American Pipeline, L.P. unitholders	—	—	(29,432)
Other	363	(102)	(260)
Net cash provided by (used in) continuing activities	(235,409)	(90,710)	(228,680)
Net cash provided by (used in) discontinued activities	225,748	(511)	(511)
Net cash provided by (used in) financing activities	(9,661)	(91,221)	(229,191)
Net increase (decrease) in cash and cash equivalents	8,658	(476)	(63,148)
Decrease in cash due to deconsolidation of Plains All American Pipeline, L.P.	—	(3,425)	—
Decrease in cash due to spin-off of Plains Exploration & Production Company	(1,028)	—	—
Cash and cash equivalents, beginning of year	1,179	5,080	68,228
Cash and cash equivalents, end of year	$ 8,809	$ 1,179	$ 5,080

See notes to consolidated financial statements

PLAINS RESOURCES INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2002	2001	2000
		(in thousands)	
Net Income	$ 37,532	$153,331	$40,815
Other Comprehensive Income (Loss):			
From continuing operations:			
Cumulative effect of accounting change, net of tax benefit of $71	—	(111)	—
Commodity hedging contracts:			
Change in fair value, net of taxes of $(223) and $75	(1,003)	766	—
Reclassification adjustment for settled contracts net of tax benefit of $7	(10)	—	—
Interest rate swap, net of taxes of $(13) and $84	(20)	131	—
Minimum pension liability adjustment, net of taxes of $66 and $(272)	106	(421)	—
Equity in other comprehensive income changes of Plains All American Pipeline, L.P., net of taxes of $56 and $(1,500)	19	(2,319)	—
	(908)	(1,954)	—
From discontinued operations:			
Commodity hedging contracts:			
Cumulative effect of accounting change, net of tax benefit of $4,454	—	6,967	—
Change in fair value, net of taxes of $(24,970) and $7,634	(37,298)	10,978	—
Reclassification adjustment for settled contracts net of taxes of $(5,897) and $1,388	8,850	(2,061)	—
Interest rate swap, net of tax benefit of $119	(178)	—	—
Minimum pension liability adjustment, net of tax benefit of $77	(116)	—	—
	(28,742)	15,884	—
Other comprehensive income (loss)	(29,650)	13,930	—
Comprehensive Income	$ 7,882	$167,261	$40,815

See notes to consolidated financial statements.

PLAINS RESOURCES INC.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	2002		2001		2000	
	Shares	Amount	Shares	Amount	Shares	Amount
			(in thousands)			
Series D Cumulative Convertible Preferred Stock						
Balance, beginning of year	47	$ 23,300	47	$ 23,300	47	$ 23,300
Preferred stock dividends			—	—	—	—
Balance, end of year	47	23,300	47	23,300	47	23,300
Series H Cumulative Convertible Preferred Stock						
Balance, beginning of year	—	—	170	84,785	—	—
Shares issued upon conversion of redeemable preferred stock	—	—	—	—	170	84,785
Conversion of preferred stock into common	—	—	(170)	(84,785)	—	—
Balance, end of year	—	—	—	—	170	84,785
Common Stock						
Balance, beginning of year	27,677	2,768	18,747	1,875	17,924	1,792
Common stock issued upon exercise of options, warrants and other	371	38	1,041	103	557	56
Conversion of preferred stock into common	—	—	7,889	790	266	27
Balance, end of year	28,048	2,806	27,677	2,768	18,747	1,875
Additional Paid-in Capital						
Balance, beginning of year		268,520		139,203		130,027
Common stock issued upon exercise of options, warrants and other		4,398		18,429		5,223
Restricted stock awards						
Issuance of restricted stock		2,955		—		—
Deferred compensation		(2,711)		—		—
Conversion of preferred stock into common		—		110,888		3,958
Redemption of preferred stock		—		—		(5)
Balance, end of year		273,162		268,520		139,203
Retained Earnings (Deficit)						
Balance, beginning of year		37,676		(88,410)		(114,500)
Net income		37,532		153,331		40,815
Preferred stock dividends		(1,400)		(27,245)		(14,725)
Treasury stock issued for less than cost		(927)		—		—
Spinoff of Plains Exploration & Production Company		(176,763)		—		—
Balance, end of year		(103,882)		37,676		(88,410)
Accumulated Other Comprehensive Income						
Balance, beginning of year		13,930		—		—
Other comprehensive income		(29,650)		13,930		—
Spinoff of Plains Exploration & Production Company		12,858		—		—
Balance, end of year		(2,862)		13,930		—
Treasury Stock						
Balance, beginning of year	(4,121)	(91,342)	(1,291)	(23,613)	—	—
Purchase of common stock	—	—	(2,830)	(67,729)	(1,291)	(23,613)
Common stock issued upon exercise of options	267	4,327	—	—	—	—
Balance, end of year	(3,854)	(87,015)	(4,121)	(91,342)	(1,291)	(23,613)
Total		$ 105,509		$254,852		$ 137,140

See notes to consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 — Organization and Significant Accounting Policies

Organization

The consolidated financial statements of Plains Resources Inc. ("Plains", "our", or "we") include the accounts of all wholly owned subsidiaries and for periods prior to January 1, 2001, Plains All American Pipeline, L.P. ("PAA"). As discussed in Note 2, in June 2001 we reduced our interest in PAA from 54% to 33% and as a result we no longer have the ability to exercise control over the operations of PAA. Accordingly, effective January 1, 2001, our minority interest investment in PAA is accounted for using the equity method of accounting. Under the equity method, we no longer consolidate the assets, liabilities and operating activities of PAA, but instead our ownership interest in PAA is reflected as an investment in the balance sheet and we record our share of PAA's results of operations. For periods prior to January 1, 2001 the assets, liabilities and results of operations of PAA are consolidated in our financial statements

On July 3, 2002 we contributed all of the capital stock of our subsidiaries that owned oil and gas properties offshore California and in Illinois to our wholly-owned subsidiary Plains Exploration & Production Company ("PXP"). PXP also directly owned our onshore California oil and gas properties. We also contributed to PXP the intercompany payables that PXP and its subsidiaries owed to us.

On July 3, 2002 PXP (i) issued $200.0 million of 8.75% senior subordinated notes due 2012; and (ii) entered into a $300.0 million revolving credit facility. PXP distributed the net proceeds of $195.3 million from the 8.75% notes and $116.7 million in initial borrowings under the credit facility to us and we used such amounts to redeem our 10.25% senior subordinated notes on August 2, 2002 ($287.0 million) and to repay amounts outstanding under our credit facility ($25.0 million).

On December 18, 2002 we distributed 100 percent of the common shares of PXP to the holders of record of our common stock as of December 11, 2002 (the "spin-off"). Each stockholder received one share of PXP common stock for each share of our common stock held. Prior to the spin-off, we borrowed $45.0 million under a new term loan facility and used a portion of the proceeds to make a $40.0 million cash capital contribution to PXP. In addition, prior to the spin-off we transferred to PXP $12.2 million in cash and certain assets and PXP assumed certain liabilities, primarily related to land, unproved oil and gas properties, office equipment and pension obligations.

We received a letter ruling from the IRS on May 22, 2002, as supplemented on November 5, 2002, to the effect that the spin-off will qualify as a tax-free distribution. A letter ruling from the IRS, while generally binding on the IRS, may under certain circumstances be retroactively revoked or modified by the IRS. A letter ruling is based on the facts and representations presented in the request for that ruling. Generally, an IRS letter ruling will not be revoked or modified retroactively if there has been no misstatement or omission of material facts, the facts at the time of the transaction are not materially different from the facts upon which the IRS letter ruling was based, and there has been no change in the applicable law. We are not aware of any facts or circumstances that would cause the representations in the ruling request to be untrue or incomplete in any material respect.

As a result of the spin-off, the historical results of the operations of PXP are reflected in our financial statements as "discontinued operations". In connection with the spin-off, we entered into certain agreements with PXP, see Note 11.

All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the prior year statements to conform to the current year presentation.

We are an independent energy company that is currently engaged in the "Upstream" oil and gas business. The Upstream business acquires, exploits, develops, explores for and produces oil and gas. Our Upstream activities are all located in the United States. Prior to the reduction in our interest in PAA, we also participated directly in the "Midstream" oil and gas business, which consists of the marketing, transportation and terminalling of oil. We continue to participate indirectly in the Midstream oil and gas business through our minority interest investment in PAA. All of PAA's Midstream activities are conducted in the United States and Canada.

Significant Accounting Policies

Oil and Gas Properties. We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration, exploitation and development activities are capitalized. Such costs include internal general and administrative costs such as payroll and related benefits and costs directly attributable to employees engaged in acquisition, exploration, exploitation and development activities. General and administrative costs associated with production, operations, marketing and general corporate activities are expensed as incurred. These capitalized costs along with our estimate of future development and abandonment costs, net of salvage values and other considerations, are amortized to expense by the unit-of-production method using engineers' estimates of proved oil and gas reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated. Interest is capitalized on oil and gas properties not subject to amortization and in the process of development. Proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales involve a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized. Unamortized costs of proved properties are subject to a ceiling which limits such costs to the present value of estimated future cash flows from proved oil and gas reserves of such properties (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures and abandonment costs (net of salvage values), and estimated future income taxes thereon.

Other Property and Equipment. Other property and equipment at December 31, 2002 is recorded at cost and consists of computer hardware and software and is fully depreciated. Net gains or losses on property and equipment disposed of are included in interest and other income in the period in which the transaction occurs.

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 the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include (1) oil and gas reserves, (2) depreciation, depletion and amortization, including future abandonment costs, (3) income taxes and related valuation allowance, and (4) accrued liabilities. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Cash and Cash Equivalents. Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. At December 31, 2002 and 2001, the majority of cash and cash equivalents is concentrated in two institutions and at times may exceed federally insured limits. We periodically assess the financial condition of the institutions and believe that our credit risk is minimal.

Inventory. Our oil inventories are carried at cost. Materials and supplies inventory is stated at the lower of cost to produce or market with cost determined on an average cost method.

Inventory consists of the following (in thousands):

	December 31, 2002	December 31, 2001
Continuing operations		
Oil	$1,482	$1,039
Materials and supplies	823	1,053
	2,305	2,092
Discontinued operations	—	4,629
	$2,305	$6,721

Other Assets. Other assets consists of the following (in thousands):

	December 31, 2002	December 31, 2001
Continuing operations		
Restricted cash	$5,000	$ —
Commodity hedging contracts and other derivatives	29	34
Debt issue costs, net	612	3,566
Receivable from PXP	3,202	—
Other	1,024	1,587
	9,867	5,187
Discontinued operations	—	18,827
	$9,867	$24,014

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization.

Federal and State Income Taxes. Income taxes are accounted for in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes ("SFAS 109"). 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 bases of assets and liabilities using tax rates in effect for the year in which the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more than likely than not that the related tax benefits will not be realized.

Under the terms of a tax allocation agreement, PXP's taxable income or loss prior to the spin-off is included in the consolidated income tax returns filed by us. Each member of a consolidated group is jointly and severally liable for the federal income tax liability of each other member of the consolidated group. Accordingly, although this agreement allocates tax liabilities between us and PXP during the period in which PXP is included in our consolidated group, we could be liable if any federal tax liability is incurred, but not discharged, by any other member of our consolidated group. To the extent our net operating losses are used in the consolidated return to offset PXP's taxable income from operations during the period January 1, 2002 through the spin-off, PXP will reimburse us for the reduction in our federal income tax liability resulting from the utilization of such net operating losses, but such reimbursement shall not exceed $3.0 million exclusive of any interest accruing under the agreement. At December 31, 2002 current assets and other assets include $0.2 million and $3.2 million, respectively, of income taxes receivable from PXP with respect to periods subsequent to the reorganization and the reimbursement due us with respect to state taxes and the utilization of net operating losses.

Revenue Recognition. Oil revenue from our interests in producing wells is recognized when the production is delivered and the title transfers. Transportation costs incurred in connection with such operations are reflected as an operating cost.

PAA's gathering and marketing revenues are accrued at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser, and purchases are accrued at the time title to the product purchased transfers to PAA, which occurs upon our receipt of the product. PAA's terminalling and storage revenues are recognized at the time service is performed and revenues for the transportation of oil are recognized based upon regulated and non-regulated tariff rates and the related transported volumes.

Derivative Financial Instruments (Hedging). We utilize various derivative instruments to reduce our exposure to decreases in the market price of oil. The derivative instruments consist primarily of oil swap and option contracts entered into with financial institutions. We also utilize interest rate swaps to manage the interest rate exposure on our long-term debt.

Stock-based Employee Compensation. In October 1995, the Financial Accounting Standards Board issued SFAS 123, which established financial accounting and reporting standards for stock-based employee compensation. SFAS 123 defines a fair value based method of accounting for an employee stock option or similar equity instrument. SFAS 123 also allows an entity to continue to measure compensation cost for those instruments using the intrinsic value-based method of accounting prescribed by APB 25. We have elected to follow APB 25 and related interpretations in accounting for our employee stock options because, as discussed below, the alternative fair value accounting provided for under SFAS 123 requires the use of option valuation models that were not developed for use in valuing employee stock options. Under APB 25, if the exercise price of our employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized in the financial statements. The compensation expense recorded under APB 25 for our restricted stock awards is the same as that determined under SFAS 123.

Pro forma information regarding net income and earnings per share is required by SFAS 123 and has been determined as if we had accounted for our employee stock options under the fair value method as provided therein. The fair value for the options was estimated at the date of grant using a Black-Scholes option pricing model with the following weighted average assumptions for grants in 2002, 2001 and 2000: risk-free interest rates of 3.0% for 2002, 2.5% for 2001 and 6.3% for 2000; a volatility factor of the expected market price of our common stock of 0.33 for 2002, 0.50 for 2001 and 0.50 for 2000; no expected dividends; and weighted average expected option lives of 4.4 years in 2002, 5.3 years in 2001 and 2.6 years in 2000. For purposes of pro forma disclosures, the estimated fair value of the options is amortized to expense over the options' vesting period.

The Black-Scholes option valuation model and other existing models were developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of and are highly sensitive to subjective assumptions including the expected stock price volatility. Because our employee stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in our opinion, the existing models do not provide a reliable single measure of the fair value of its employee stock options.

Set forth below is a summary of our net income and earnings per share as reported and pro forma as if the fair value based method of accounting defined in SFAS 123 had been applied (in thousands, except per share data).

	Year Ended December 31,		
	2002	2001	2000
Net income, as reported	$36,132	$126,086	$26,090
Add: Stock based employee compensation expense included in reported net income, net of related tax effects	929	2,586	—
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(4,337)	(3,002)	(792)
Pro forma net income	$32,724	$125,670	$25,298
Earnings per share:			
Basic-as reported	$ 1.51	$ 5.98	$ 1.46
Basic-pro forma	$ 1.37	$ 5.96	$ 1.42
Diluted-as reported	$ 1.48	$ 4.75	$ 1.39
Diluted-pro forma	$ 1.34	$ 4.74	$ 1.35

Sale of Units by PAA. When PAA sells additional units to a third party, resulting in a change in our percentage ownership interest, we recognize a gain or loss in our consolidated statement of operations if the selling price per unit is more or less than our average carrying amount per unit.

Recent Accounting Pronouncements. Statement of Accounting Standards, or SFAS, No. 143, "Accounting for Asset Retirement Obligations" becomes effective January 1, 2003. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Each period the liability is accreted to its then present value, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. For all historical periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and these costs have been amortized as a component of our depletion expense.

We have completed our assessment of SFAS No. 143 and we estimate that at January 1, 2003 the present value of our future Asset Retirement Obligation ("ARO") for oil and gas properties and equipment is approximately $2.6 million. We estimate that the cumulative effect of our adoption of SFAS No. 143 and the change in accounting principle will result in an increase in net income during the first quarter of 2003 of $1.5 million (reflecting a $2.9 million decrease in accumulated DD&A, partially offset by $1.3 million in accretion expense), $0.9 million net of taxes. We estimate that we will record a liability of $2.6 million and an asset of $1.2 million in connection with the adoption of SFAS 143. There will be no impact on our cash flows as a result of adopting SFAS No. 143.

In July 2002, SFAS No. 146, "Accounting For Costs Associated with Exit or Disposal Activities" was issued. SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002 and does not require previously issued financial statements to be restated. We will account for exit or disposal activities initiated after December 31, 2002 in accordance with the provisions of SFAS 146.

In December 2002, SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure — an amendment of FASB Statement No. 123" was issued. SFAS 148 amends SFAS 123, "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of SFAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The provisions of SFAS 148 are effective for financial statements for fiscal years ending after December 15, 2002. SFAS 148 does not change the provisions of SFAS 123 that permit entities to continue to apply the intrinsic value method of Accounting Principles Bulletin No. 25, "Accounting for Stock Issued to Employees". We will continue to account for stock-based compensation on accordance with the provisions of APB No. 25. We have provided the disclosures required by SFAS 148 in these financial statements.

In November 2002 FASB interpretation, or FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others" was issued. FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of FIN 45. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. The disclosures required by FIN 45 are included in these financial statements.

In January 2003 FASB Interpretation 46, or FIN 46, "Consolidation of Variable Interest Entities" was issued. FIN 46 identifies certain off-balance sheet arrangements that meet the definition of a variable interest entity (VIE). The primary beneficiary of a VIE is the party that is exposed to the majority of the risks and/or returns of the VIE. In future accounting periods, the primary beneficiary will be required to consolidate the VIE. In addition, more extensive disclosure requirements apply to the primary beneficiary, as well as other significant investors. We do not believe we participate in any arrangement that would be subject to the provisions of FIN 46.

In the fourth quarter of 2000, we adopted Securities and Exchange Commission ("SEC") Staff Accounting Bulletin 101, "Revenue Recognition in Financial Statements" ("SAB 101"). As a result, we record revenue from oil production in the period it is sold as opposed to when it is produced and carry any unsold production as inventory valued at historical cost to produce. The total effect of implementing SAB 101 was to reduce reported sales volumes by 144,000 barrels for 2000 and net income for the year by $175,000, including a $121,000 reduction for the cumulative effect of prior years.

Note 2 — Discontinued Operations

As discussed in Note 1, on December 18, 2002 we distributed the common shares of PXP to the holders of record of our common stock as of December 11, 2002. As a result of the spin-off, we have accounted for the business of PXP as a discontinued operation.

The results of operations of PXP, which have been reclassified as discontinued operations for all periods presented in the Consolidated Statements of Income, are summarized as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Revenues	$ 181,184	$204,139	$142,451
Costs and expenses	(115,195)	(98,110)	(81,395)
Income from operations	65,989	106,029	61,056
Other income (expense)	(20,961)	(16,948)	(15,542)
Income before income taxes	45,028	89,081	45,514
Income tax expense	(17,228)	(34,388)	(16,765)
Income from discontinued operations	$ 27,800	$ 54,693	$ 28,749

Amounts included in our Consolidated Balance Sheet at December 31, 2001 with respect to the business of PXP are summarized as follows (in thousands):

	December 31, 2001
Assets	
Current assets	$ 42,811
Property and equipment, net	455,117
Other assets	18,827
Liabilities and Stockholders' Equity	
Current liabilities	41,879
Long-term debt	1,022
Other long-term liabilities	1,413
Accumulated other comprehensive income	15,884

Note 3 — Investment in Plains All American Pipeline, L.P.

At December 31, 2002, our aggregate 25% ownership in PAA consisted of: (i) a 44% ownership interest in the 2% general partner interest and incentive distribution rights, (ii) 45%, or approximately 4.5 million, of the Subordinated Units and (iii) 20% or approximately 7.9 million of the common units (including approximately 1.3 million Class B common units). Our ownership in PAA decreased in 2002 and 2001 as a result of the sale of a portion of our interest and PAA's public equity offerings.

Sale of PAA Interest

In a series of transactions on June 8, 2001, we sold a portion of our interest in PAA to a group of investors and certain members of PAA management for aggregate consideration of approximately $155.2 million (consisting of $110.0 million in cash and $45.2 million in Series F Cumulative Convertible Preferred Stock [the "Series F Preferred Stock']) and recognized a pre-tax gain of $128.3 million in connection with this sale. In addition, certain holders of the Series F Preferred Stock and Series H Convertible Preferred Stock (the "Series H Preferred Stock") converted their shares into shares of our common stock. We sold (i) 5.2 million Subordinated Units of PAA (the "Subordinated Units") for $69.5 million in cash and the redemption of 23,108 shares of Series F Preferred Stock, valued at $45.2 million; and (ii) an aggregate 54% ownership interest in the general partner of PAA for $40.5 million in cash. In addition, the investor group and certain other stockholders converted 26,892 shares of Series F Preferred Stock and 132,022 shares of Series H Preferred Stock into a total of 6.6 million shares of our common stock. On September 5, 2001, pursuant to an option granted as part of the June 8, 2001 transactions, certain members of the executive management of PAA acquired an aggregate additional 2% ownership interest in the general partner of PAA for $1.5 million in cash and notes, further reducing our ownership in the general partner of PAA to 44%. We recognized a gain of $1.1 million as a result of this transaction. These transactions in the aggregate are hereinafter referred to as "the Transactions".

As a result of the Transactions, all of the Series F Preferred Stock and all but approximately 36,000 shares of the Series H Preferred Stock were retired or converted. The remaining outstanding shares of the Series H Preferred Stock converted to 1.2 million shares of our common stock during the third quarter. Also as a result of the Transactions, certain of our employees received transaction-related bonuses and other payments and vested in benefits in accordance with the terms of certain of our employee benefit plans.

The excess of the fair value of the Series F Preferred stock as consideration for the PAA Units over the carrying value of the Series F Preferred Stock ($21.4 million) for accounting purposes is deemed to be a dividend to preferred stockholders and is deducted in determining the income available to common stockholders for the purpose of determining basic and fully diluted earnings per share in 2001. In connection with the conversion of the Series F Preferred Stock into common stock, we made a $2.5 million inducement payment representing a 20% premium to the amount of dividends that would accrue on the Series F Preferred Stock between the closing of the Transactions and the first date we could potentially cause such conversion. Such amounts are included in preferred dividends.

The Subordinated Units are subordinated in right to distributions from PAA and are not publicly traded. However, PAA's partnership agreement provides that, if certain financial tests are met, the Subordinated Units (including those retained by us) will convert into common units on a one-for-one basis commencing in 2003. In connection with the Transactions, we entered into Value Assurance Agreements with such purchasers of the Subordinated Units under the terms of which we will pay the purchasers an amount per fiscal year, payable on a quarterly basis, equal to $1.85 per unit less the actual amount distributed during that year. The Value Assurance Agreements expire upon the earlier of (a) the conversion of the Subordinated Units to common units or (b) June 8, 2006.

Also in connection with the Transactions, we entered into a separation agreement with PAA pursuant to which, among other things, (a) we agreed to indemnify PAA, the general partner of PAA, and the subsidiaries of PAA against any losses or liabilities resulting from (i) the operation of the upstream business or (ii) federal or state securities laws, or the regulations of any self-regulatory authority, or other similar claims resulting from acts or omissions by us, our subsidiaries, PAA, or PAA's subsidiaries on or before the closing of the Transactions; and (b) PAA agreed to indemnify us and our subsidiaries against any losses or liabilities resulting from the operation of the midstream business. We also entered into a pension and employee benefits assumption and transition agreement pursuant to which the general partner of PAA and us agreed to the transition of certain employees to such general partner, the provision of certain benefits with respect to such transfer, and the provision of other transition services by us.

In addition, we agreed to contribute 287,500 of our Subordinated Units to PAA's general partner to be used for option grants to officers and key employees. These Subordinated Units are considered to be a contribution to the general partner and we will receive no reimbursement for such units. Also, at the time of the Transactions, certain of our employees, who are now employees of PAA's general partner, held "in-the-money" but unvested Plains stock options which were subject to forfeiture due to the transfer of employment. We agreed to substitute, based on the present value of such options, a contingent grant of 51,000 Subordinated Units that vest on the same schedule the stock options were to vest.

PAA Equity Offerings

In May 2001, PAA issued 4.0 million common units in a public equity offering. We recognized a gain of $19.6 million resulting from the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA due to the sale of the units. As a result of the offering, we made a general partner capital contribution of approximately $2.0 million. In October 2001, PAA issued 4.5 million common units in a public offering. As a result of the offering, we made a general partner capital contribution of approximately $1.0 million, and our aggregate ownership interest in PAA was reduced to approximately 29%. We recognized a gain of approximately $19.2 million resulting from the increase in book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA resulting from this public offering.

In August 2002, PAA issued 6.3 million common units in a public equity offering. We recognized a gain of $14.5 million resulting from the increase in the book value of our equity in PAA to reflect our proportionate share of the increase in the underlying net assets of PAA due to the sale of the units. As a result of the offering, we made a general partner capital contribution of approximately $1.3 million, and our aggregate ownership interest in PAA was reduced to approximately 25%.

PAA Financial Statement Information

The following table presents summarized financial statement information of PAA (in thousands of dollars):

	Year Ended December 31,	
	2002	2001
Revenues	$8,384,223	$6,868,215
Cost of sales and operations	8,209,932	6,725,954
Gross margin	174,291	142,261
Operating income	94,560	71,368
Income before cumulative effect of accounting change	65,292	43,671
Net income	65,292	44,179

	December 31,	
	2002	2001
Current assets	$ 602,935	$ 558,082
Property and equipment, net	952,753	604,919
Other assets	110,887	98,250
Total assets	1,666,575	1,261,251
Current liabilities	637,249	505,160
Long-term debt	509,736	351,677
Other long-term liabilities	7,980	1,617
Partners' capital	511,610	402,797
Total liabilities and partners' capital	1,666,575	1,261,251

Note 4 — Derivative Instruments and Hedging Activities

We have entered into various derivative instruments to reduce our exposure to fluctuations in the market price of oil. The derivative instruments consist primarily of oil swap and option contracts entered into with financial institutions. On January 1, 2001 we adopted SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 ("SFAS 133"). Under SFAS 133, all derivative instruments are recorded on the balance sheet at fair value. If the derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. If the derivative qualifies for hedge accounting, the unrealized gain or loss on the derivative is deferred in accumulated Other Comprehensive Income ("OCI"), a component of Stockholder's Equity. On January 1, 2001, in accordance with the transition provisions of SFAS 133, we recorded a loss of $0.1 million in OCI, representing the cumulative effect of an accounting change to recognize at fair value all cash flow derivatives. We recorded cash flow hedge derivative assets and liabilities of $10.9 million and $13.9 million, respectively, and a net-of-tax non-cash charge of $2.0 million was recorded in earnings as a cumulative effect adjustment. At December 31, 2002 all open positions qualified for hedge accounting.

Gains and losses on oil hedging instruments related to OCI and adjustments to carrying amounts on hedged volumes are included in oil revenues in the period that the related volumes are delivered. Gains and losses on oil hedging instruments representing hedge ineffectiveness, which is measured on a quarterly basis, are included in oil revenues in the period in which they occur. No ineffectiveness was recognized in 2002 or 2001, except as discussed below. For purposes of our financial statements, effective October 2001 we implemented Derivatives Implementation Group, Issue G20, "Cash Flow Hedges: Assessing and Measuring the Effectiveness of a Purchased Option Used in a Cash Flow Hedge", or DIG Issue G20, which provides guidance for basing the assessment of hedge effectiveness on total changes in an option's cash flows rather than only on changes in the option's intrinsic value. Implementation of DIG Issue G20 has reduced earnings volatility since it allows us to include changes in the time value of purchased options and collars in the assessment of hedge effectiveness. Time value changes were previously recognized in current earnings since we excluded them from the assessment of hedge effectiveness. Oil revenues for the year ended December 31, 2001 include a $0.3 million non-cash loss related to the ineffective portion of the cash flow hedges representing the fair value change in the time value of options for the nine months before the implementation of DIG Issue G20.

At December 31, 2001, OCI from continuing operations consisted of $0.8 million ($0.5 million, net of tax) of unrealized gains on our open oil hedging instruments, $3.8 million ($2.3 million, net of tax) of unrealized loss related to our equity in the OCI loss of PAA, and $0.7 million ($0.4 million, net of tax) related to pension liabilities. At December 31, 2002 OCI consisted of unrealized losses of: (i) $0.4 million ($0.3 million, net of tax) on our oil hedging instruments, (ii) $3.7 million ($2.3 million, net of tax) related to our equity in the OCI loss of PAA, and (iii) $0.5 million ($0.3 million, net of tax) related to pension liabilities. At December 31, 2002, the liability related to our open oil hedging instruments was included in current liabilities ($0.4 million), and deferred income taxes (a tax benefit of $0.2 million).

During 2002 oil sales revenues were reduced by $0.6 million to reflect non-cash expense related to the amortization of option premiums. As of December 31, 2002, $0.4 million ($0.2 million, net of tax) of deferred net losses on our oil hedging instruments recorded in OCI are expected to be reclassified to earnings during the next twelve-month period.

At December 31, 2002 we had the following open oil hedge positions:

	Barrels per Day	
	2003	2004
Swaps		
Average price $26.10/bbl	1,500	—
Average price $23.50/bbl	—	500

Location and quality differentials attributable to our properties are not included in the foregoing prices. Because of the quality and location of our oil production, these adjustments will reduce our net price per barrel.

Note 5 — Long-Term Debt and Credit Facilities

Long-term debt consists of the following at December 31, 2002 and 2001 (in thousands):

	2002		2001	
	Current	Long-Term	Current	Long-Term
Continuing operations				
Secured term loan facility, bearing interest at 4.4%	$18,000	$27,000	$ —	$ —
Revolving credit facility, bearing interest at 4.2%	—	—	—	11,500
10.25% senior subordinated notes net of repurchased notes of $7.55 million and unamortized premium of $2.1 million	—	—	—	269,539
Discontinued operations	—	—	511	1,533
	$18,000	$27,000	$511	$282,572

Aggregate total maturities of long-term debt in the next five years are as follows: 2003 — $18.0 million; 2004 — $18.0 million; and 2005 — $9.0 million.

Secured Term Loan Facility

On December 9, 2002 we entered into a $45.0 million secured term loan facility with a group of banks. The term loan is repayable in 10 quarterly installments of $4.5 million each commencing on February 28, 2003 with a final maturity of May 31, 2005. Amounts outstanding under the term loan bear an annual interest rate, at our election, equal to either the Base Rate (as defined in the agreement) plus 1.5%, or LIBOR plus 3%. The term loan requires that we maintain $5.0 million on deposit in a debt service reserve account with one of the lending banks.

To secure the term loan, we pledged 100% of the shares of stock of our subsidiaries and pledged 4,950,000 of our PAA common units. To the extent that the outstanding principal under the term loan exceeds the balance in the debt reserve account (as defined in the agreement) plus 50% of the fair market value of the pledged common units, we are required to repay the excess. The fair market value of the pledged units is determined based on the closing price of PAA common units on the New York Stock Exchange.

The term loan contains covenants that limit our ability, as well as the ability of our subsidiaries, to incur additional debt, make investments, create liens, enter into leases, sell assets, change the nature of our business or operations, guarantee other indebtedness, enter into certain types of hedge agreements, enter into take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, if an event of default exists, the term loan prohibits us from paying dividends or repurchasing or redeeming shares of any class of capital stock. The term loan requires us to maintain a minimum consolidated tangible net worth ($80 million at December 31, 2002) and a consolidated debt service coverage ratio (as defined in the agreement) of 1.0 to 1.0. At December 31, 2002 we were in compliance with the covenants contained in the term loan facility.

Revolving Credit Facility and 10.25% Senior Subordinated Notes Due 2006

At December 31, 2001 we had a $225.0 million revolving credit facility with a group of banks. At December 31, 2001, $11.5 million in borrowings and letters of credit of $0.6 million were outstanding under the revolving credit facility. On July 3, 2002 all amounts outstanding under the revolving credit facility were repaid and the credit facility was terminated.

At December 31, 2001 we had $267.5 million principal amount of 10.25% Senior Subordinated Notes Due 2006 (the "10.25% notes") outstanding, bearing a coupon rate of 10.25%. The 10.25% notes were redeemable, at our option at 105.13% of the principal amount through March 15, 2002, at 103.42% on or after March 15, 2002, at 101.71% on or after March 15, 2003 and at 100% on or after March 15, 2004 plus, in each case, accrued interest to the date of redemption. In August 2002 we redeemed the 10.25% notes for $287.0 million. The redemption payment consisted of the $267.5 million principal amount outstanding; a $9.1 million call premium due as a result of the early redemption; and $10.4 million in interest accrued and payable on the redemption date. Upon redemption, all guarantees with respect to the 10.25% notes were terminated.

As a result of the redemption of the 10.25% notes and the termination of our revolving credit facility, we recognized a $10.3 million loss on debt extinguishment;

Note 6 — Unauthorized Trading Losses

In November 1999, we discovered that a former employee of PAA had engaged in unauthorized trading activity, resulting in losses of approximately $174.0 million, including estimated associated costs and legal expenses. Approximately $7.1 million of the unauthorized trading losses were recognized in 1998 and the remainder in 1999. In 2000, we recognized an additional $8.0 million charge for litigation related to the unauthorized trading losses. All litigation with respect to this matter has been settled.

Note 7 — PAA Acquisitions and Dispositions

All American Pipeline Linefill Sale and Asset Disposition

In March 2000, PAA sold the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas to a unit of El Paso Corporation for $129.0 million. PAA realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove some equipment. The proceeds from the sale were used to reduce the outstanding debt of PAA. PAA recognized a gain of approximately $20.1 million in connection with the sale.

PAA had suspended shipments of oil on this segment of the pipeline in November 1999. At that time, PAA owned approximately 5.2 million barrels of oil in the segment of the pipeline. PAA sold this oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million and recognized gains of approximately $28.1 million and $16.5 million in 2000 and 1999, respectively, in connection with the sale of the linefill.

Note 8 — Redeemable Preferred Stock

Series F Cumulative Convertible Preferred Stock

On December 14, 1999, we sold in a private placement 50,000 shares of Series F Preferred Stock for $50.0 million. As discussed in Note 3, in conjunction with the Transactions we redeemed 23,108 shares of the Series F Preferred Stock and the remaining 26,892 shares were converted into 2.2 million shares of our common stock. Each share of the Series F Preferred Stock had a stated value of $1,000 per share and bore a dividend of 10% per annum.

Note 9 — Common Stock and Non-Redeemable Preferred Stock

Common and Preferred Stock

We have authorized capital stock consisting of 50.0 million shares of common stock, $0.10 par value, and 2 million shares of preferred stock, $1.00 par value. At December 31, 2002 and 2001, there were 24.1 million shares and 23.6 million shares of common stock outstanding (net of treasury shares), respectively, and 46,600 shares of preferred stock outstanding.

Series D Cumulative Convertible Preferred Stock

We have outstanding 46,600 shares of Series D Cumulative Convertible Preferred Stock, or Series D Preferred, that have an aggregate stated value of $23.3 million and are redeemable at our option at 140% of stated value. If not previously redeemed or converted, the Series D Preferred will automatically convert into shares of common stock in 2012. Each share of Series D Preferred has a stated value of $500 and bears an annual dividend of $30.00 per share.

As a result of the spin-off, the number of shares of common stock into which the Series D Preferred is convertible increased from 932,000 shares to 1,671,416 shares as a result of the reduction in the conversion price from $25.00 per share of common stock to $13.94 per share. The reduction in the conversion price of the Series D Preferred was determined by multiplying the former conversion price of the Series D Preferred ($25.00) by a fraction, the denominator of which was $22.27 (the closing price per share of our common stock as of the record date for the spin-off), and the numerator of which was $12.42 (the closing price per share of our common stock as of the record date for the spin-off less the agreed on fair market value per share of the PXP common stock distributed in the spin-off). The holders of the Series D Preferred did not receive any PXP securities as a result of the spin off.

Series H Convertible Preferred Stock

In December 2000, we exchanged 169,571 shares of Series G Preferred Stock for 169,571 shares of Series H Preferred Stock. The Series H Preferred Stock was convertible into the same number of shares of common stock as the Series G Preferred Stock (33.33 shares of common), but did not bear a dividend and did not contain a mandatory redemption feature. As discussed in Note 3, in conjunction with the Transactions, 132,022 shares of the Series H Preferred Stock were converted into 4.4 million shares of our common stock. In the third quarter of 2001 the remaining outstanding shares were converted into 1.2 million common shares.

Treasury Stock

Our Board of Directors has authorized the repurchase of up to eight million shares of our common stock. In 2001, we repurchased 2.8 million common shares at a cost of $67.7 million, and in 2000 we repurchased 1.3 million common shares at a cost of $23.6 million. No repurchases were made in 2002.

Note 10 — Earnings Per Share

The following is a reconciliation of the numerators and the denominators of the basic and diluted earnings per share computations for income (loss) from continuing operations before the cumulative effect of accounting changes for the years ended December 31, 2002, 2001 and 2000 (in thousands, except per share amounts):

	Year Ended December 31,					
	2002		2001		2000	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
Income from continuing operations	$ 9,732	$ 9,732	$100,624	$100,624	$ 12,187	$ 12,187
Preferred dividends	(1,400)	(1,400)	(27,245)	(23,880)	(14,725)	(14,725)
Income (loss) from continuing operations available to common stockholders	8,332	8,332	73,379	76,744	(2,538)	(2,538)
Income from discontinued operations	27,800	27,800	54,693	54,693	28,749	28,749
Effect of accounting changes, net of tax	—	—	(1,986)	(1,986)	(121)	(121)
Net income available to common stockholders	$36,132	$36,132	$126,086	$129,451	$ 26,090	$ 26,090
Weighted average number of shares of common stock outstanding	23,871	23,871	21,090	21,090	17,845	17,845
Effect of dilutive securities						
Convertible preferred stock	—	—	—	5,280	—	—
Employee stock options and warrants	—	580	—	874	—	855
Average common shares, including dilutive effect	23,871	24,451	21,090	27,244	17,845	18,700
Earnings (loss) per share						
Continuing operations	$ 0.35	$ 0.34	$ 3.48	$ 2.81	$ (0.14)	$ (0.14)
Discontinued operations	1.16	1.14	2.59	2.01	1.61	1.54
Effect of accounting changes	—	—	(0.09)	(0.07)	(0.01)	(0.01)
Net income available to common stockholders	$ 1.51	$ 1.48	$ 5.98	$ 4.75	$ 1.46	$ 1.39

In 2002 and 2000 our preferred stock was not included in the computation of diluted earnings per share because the effect was antidilutive. See Note 15 for additional information concerning outstanding options and warrants.

Note 11 — Income Taxes

Our deferred income tax assets and liabilities at December 31, 2002 and 2001 consist of the tax effect of income tax carryforwards and differences related to the timing of recognition of certain types of costs as follows (in thousands):

	December 31,	
	2002	2001
U.S. Federal		
Deferred tax assets:		
Net operating losses	$16,232	$ 18,142
Percentage depletion	—	2,450
Tax credit carryforwards	6,040	8,988
Excess outside tax basis over outside book basis	423	9,979
Commodity hedging contracts and other	1,941	4,926
	24,636	44,485
Deferred tax liabilities:		
Net oil & gas acquisition, exploration and development costs	(7,277)	(63,693)
Commodity hedging contracts and other	—	(9,028)
	17,359	(28,236)
Valuation allowance	—	(2,450)
	17,359	(30,686)
States		
Deferred tax liability	(1,175)	(14,074)
EOR credit	734	—
	(441)	(14,074)
Foreign		
Excess outside tax basis over outside book basis	39	466
Net deferred tax asset (liability)	$16,957	$(44,294)

At December 31, 2002, we have carryforwards of approximately $46.4 million of regular tax net operating losses ("NOL"), $2.2 million of alternative minimum tax credits and $3.8 million of enhanced oil recovery ("EOR") credits. At December 31, 2002, we also had approximately $15.0 million of alternative minimum tax NOL carryforwards available as a deduction against future alternative minimum tax income. The NOL carryforwards expire in 2019.

The valuation allowance with respect to percentage depletion was $2.5 million at December 31, 2001 and $2.6 million as of December 31, 2000 and 1999. In 2002 the deferred tax asset and the related valuation allowance were written off.

Set forth below is a reconciliation between the income tax provision (benefit) computed at the United States statutory rate on income (loss) before income taxes and the income tax provision in the accompanying consolidated statements of income (in thousands):

	Year Ended December 31,		
	2002	2001	2000
U.S. federal income tax provision at statutory rate	$ 5,575	$58,771	$6,230
State income taxes, net of federal benefit	559	5,292	(549)
Foreign income taxes, net of federal benefit	1,479	916	—
Other	(1,507)	2,093	(53)
Income tax expense (benefit) on income before extraordinary item	6,106	67,072	5,628
Income tax benefit allocated to cumulative effect of accounting change	—	(228)	(76)
Income tax provision	$ 6,106	$66,844	$5,552

Under the terms of a tax allocation agreement, PXP has agreed to indemnify us if the spin-off is not tax-free as a result of various actions taken by PXP or with respect to PXP's failure to take various actions. In addition, PXP agreed that, during the three-year period following the spin-off, without our prior written consent, they will not engage in transactions that could adversely affect the tax treatment of the spin-off unless they obtain a supplemental tax ruling from the IRS or a tax opinion acceptable to us from a nationally recognized tax counsel to the effect that the proposed transaction would not adversely affect the tax treatment of the spin-off or provide adequate economic security to us to ensure PXP would be able to comply with its obligation under this agreement. PXP may not be able to control some of the events that could trigger this indemnification obligation.

Note 12 — Early Extinguishment of Debt

In 2002 we adopted SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections". SFAS 145 rescinds SFAS 4 and SFAS 64 related to classification of gains and losses on debt extinguishment such that most debt extinguishment gains and losses are no longer be classified as extraordinary. SFAS 145 also amends SFAS 13 with respect to sales-leaseback transactions. The provisions of SFAS 145 with respect to sales-leaseback transactions have no effect on our financial statements. As a result of the provisions of SFAS 145 with respect to debt extinguishments, the following items are not classified as extraordinary items in the Consolidated Statement of Income: (i) as a result of the redemption of the 10.25% notes and the termination of our credit facility, in 2002 we recognized a $10.3 million loss on debt extinguishment; and (ii) in 2000, PAA recognized a $15.2 million charge to income ($5.0 million net of minority interest of $7.0 million and deferred income taxes of $3.2 million) consisting primarily of unamortized debt issue costs related to the refinancing of PAA's credit facilities.

In addition, interest and other income for 2000 includes $4.4 million of previously deferred net gains from interest rate swaps terminated as a result of the debt extinguishment.

Note 13 — Related Party Transactions

Reimbursement of Expenses of the General Partner and Its Affiliates

Prior to the Transactions, the general partner of PAA was a wholly-owned subsidiary of Plains. As a result of the Transactions another entity was named general partner and our ownership in that entity is 44%. Previously, we had sole responsibility for conducting PAA's business and managing its operations. We did not receive any management fee or other compensation in connection with the management of PAA's business, but were reimbursed for all direct and indirect expenses incurred on its behalf. For the period from January 1, 2001 to June 8, 2001, and for the year ended December 31, 2000, we were reimbursed approximately $31.2 million and $63.8 million, respectively, for direct and indirect expenses on PAA's behalf. The reimbursed costs consisted primarily of employee salaries and benefits. PAA does not employ any persons to manage its business. These functions are provided by employees of the general partner.

Oil Marketing Agreement

PAA is the exclusive marketer/purchaser for all of our equity oil production. The marketing agreement provides that PAA will purchase for resale at market prices all of our equity oil production for which PAA charges a fee of $0.20 per barrel. For the years ended December 31, 2002, 2001 and 2000, PAA paid approximately $22.7 million, $21.3 million and $22.3 million, respectively, for the purchase of oil under the agreement, including the royalty share of production. We paid $0.2 million in marketing fees to PAA in each of 2002, 2001 and 2000.

Financing

In December 1999, we loaned PAA $114.0 million, which was repaid in May 2000. Interest on the notes was $3.3 million and $0.6 million for the years ended December 31, 2000 and 1999, respectively.

Transaction Grant Agreements

In 1998 at no cost to PAA, we agreed to grant 400,000 of our PAA common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of the general partner and its affiliates. The grants vested over a three year period subject to PAA paying distributions on common and subordinated units. Of these grants, 69,000 vested in 1999 and 133,000 vested in 2000. The remaining grants vested in 2001 as a result of the Transactions. PAA recognized noncash compensation expense related to the transaction grants of approximately $4.8 million, $2.7 million and $1.0 million in the years ended December 31, 2001, 2000, and 1999, respectively, and we reflected capital contributions of a similar amount. The noncash compensation is included in general and administrative expense in the Consolidated Statements of Income in 2000. Our share of this expense is included in our equity in the earnings of PAA in 2002 and 2001.

Agreements with PXP

In connection with the reorganization and the spin-off we entered into certain agreements with PXP, including a master separation agreement; an intellectual property agreement; the Plains Exploration & Production transition services agreement; the Plains Resources transition services agreement; and a technical services agreement.

Master separation agreement. The master separation agreement provides for the separation of substantially all of our upstream assets and liabilities, other than our Florida operations. The master separation agreement provides for, among other things: the separation; cross-indemnification provisions; allocation of fees related to these transactions between us and PXP; other provisions governing our relationship with PXP, including mandatory dispute arbitration, sharing information, confidentiality and other covenants; and a noncompetition provision.

Intellectual property agreement. The intellectual property agreement provides that we will transfer ownership and all rights associated with certain trade names, trademarks and service marks to PXP. PXP will grant us a full license to use certain trade names subject to certain limitations.

Plains Exploration & Production transition services agreement. This agreement provides that we will provide PXP management, tax, accounting, payroll, insurance, employee benefits, legal and financial services on an interim basis. Through December 31, 2002 we had charged PXP $10.8 million of the maximum $30.0 million allowed under this agreement to reimburse us for our costs of providing such services. We do not expect to charge significant additional amounts under this agreement.

Plains Resources transition services agreement. This agreement became effective as of the date of the spin-off and provides that PXP will provide us tax, accounting, payroll, employee benefits, legal and financial services on an interim basis. PXP will charge us on a monthly basis for the costs of providing such services. No charges were made to us in 2002 under the terms of this agreement. At December 31, 2002 current assets include a $1.2 million receivable from PXP related to services provided under this agreement.

Technical services agreement. The technical services agreement provides that PXP will provide our subsidiary, Calumet Florida, certain engineering and technical support services required to support operation and maintenance of the oil and gas properties owned by Calumet, including geological, geophysical, surveying, drilling and operations services, environmental and other governmental or regulatory compliance related to oil and gas activities and other oil and gas engineering services as requested, and accounting services. PXP will charge us on a monthly basis for the costs of providing such services. No charges were made to us in 2002 under the terms of this agreement.

Other

The Executive Chairman of our Board of Directors and our Chief Executive Officer and President own a limited partnership that owns 20% of Plains All American GP LLC, the general partner of PAA.

From time to time we charter private aircraft from Gulf Coast Aviation Inc. ("Gulf Coast"), which is not affiliated with us or our employees. On certain occasions, the aircraft that Gulf Coast charters is owned by the Executive Chairman of our Board of Directors. In 2002 and 2001 we paid Gulf Coast $0.4 million and $0.2 million, respectively, for aircraft chartering services provided by Gulf Coast using an aircraft owned by our Executive Chairman. The charters were arranged through arms-length dealings with Gulf Coast and the rates were market based.

Note 14 — Benefit Plans

We have a nonqualified retirement plan (the "Plan") for certain of our former officers. Benefits under the Plan are based on salary at the time of adoption, vest over a 15-year period and are payable over a 15-year period commencing at age 60. The Plan is unfunded. In connection with the spin-off, certain of the obligations were transferred to PXP and we paid PXP $0.5 million for the assumption of such obligations.

Net pension expense for the years ended December 31, 2002, 2001 and 2000 is comprised of the following components (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Service cost — benefits earned during the period	$196	$156	$ 99
Interest on projected benefit obligation	142	131	96
Amortization of prior service cost	19	31	37
Unrecognized loss	37	17	—
Net pension expense	$394	$335	$232

Summarized information of our retirement plan for the periods indicated is as follows (in thousands):

	December 31,	
	2002	2001
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 1,907	$ 1,821
Service cost	40	155
Interest cost	126	131
Settlement losses	131	271
Transfer of obligation to PXP	(510)	—
Benefits paid	(69)	(67)
Settlement payments	(252)	(1,159)
Actuarial (gains) losses	4	755
Benefit obligation at end of year	$ 1,377	$ 1,907
Amounts recognized in the consolidated balance sheets:		
Projected benefit obligation for service rendered to date	$ 1,377	$ 1,907
Plan assets at fair value	—	—
Benefit obligation in excess of fair value of plan assets	(1,377)	(1,907)
Unrecognized (gain) loss	521	720
Unrecognized prior service costs	124	310
Adjustment to recognize minimum liability	(645)	(1,030)
Net amount recognized	$(1,377)	$(1,907)

The weighted-average discount rate used in determining the projected benefit obligation was 6.75% and 7.25% for the years ended December 31, 2002 and 2001, respectively.

We also maintain a 401(k) defined contribution plan whereby we match 100% of an employee's contribution (subject to certain limitations in the plan). Matching contributions were made 50% in cash and 50% in common stock of the Company, with the number of shares for the stock match based on the market value of the common stock at the time the shares are granted, through September 30, 2002. Thereafter, matching contributions were made 100% in cash. At the time of the spin-off the plan was transferred to PXP and we established a new 401(k) plan for the employees that remained with us. The new plan is substantially identical to the plan transferred to PXP. For the years ended December 31, 2002, 2001 and 2000, defined contribution plan expense was $0.5 million, $0.3 million and $1.4 million, respectively. Such expense for 2000 includes amounts attributable to employees of the general partner of PAA.

Note 15 — Stock Compensation Plans

Stock Options

Historically, we have used stock options as a long-term incentive for our employees, officers and directors under various stock option plans. We have options outstanding under our 2001 and 1996 plans, under which a maximum of 5.6 million shares of common stock were reserved for issuance. Generally, the options are granted: (i) at an exercise price equal to or greater than the market price of the underlying stock on the date of grant; and (ii) with a pro rata vesting period of two to five years and an exercise period of five to ten years. Certain options have vesting provisions related to the market price of our common stock. If such options do not vest under such provisions, they vest at the end of a five-year period.

As a result of the spin-off, the exercise price for our stock options was adjusted to approximately 61% of the exercise price at the date of grant. The adjustment was based on the relationship of the closing price (with dividend) of our common stock on the spin-off date ($23.05 per share) less the closing price (on a "when-issued" basis) of PXP's common stock on the spin-off date ($9.10 per share), both as reported on the NYSE, and the closing price of PXP common stock ($9.10 per share).

Performance options to purchase a total of 500,000 shares of common stock were granted to two executive officers in 1996. Terms of the options provided for an exercise price of $13.50, the market price on the date of grant, and were to vest if shares of our common stock traded at or above $24.00 per share for any 20 trading days in any 30 consecutive trading day period prior to August 2001, or upon a change in control if certain conditions were met. The performance options vested in the second quarter of 2001 and we recognized $4.0 million of noncash compensation expense, which is included in general and administrative expense.

In May 2001 we granted options on 2,250,000 shares under the terms of our 2001 plan subject to the approval of such plan by our board of directors. The market price of our common stock at the time the plan was approved in July 2001 exceeded the exercise price with respect to 1,450,000 of such options and, accordingly, we recognized noncash compensation with respect to such options. During 2002 and 2001, $0.5 million and $0.3 million, respectively, in compensation expense with respect to such options is included in general and administrative expense.

A summary of the status of our stock options as of December 31, 2002, 2001, and 2000, and changes during the years ending on those dates are presented below (shares in thousands):

	2002		2001		2000	
Fixed Options	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	3,667	$20.30	2,749	$12.11	2,811	$11.06
Granted	1,474	19.32	2,464	24.02	419	13.91
Exercised	(457)	12.00	(1,431)	11.51	(444)	6.96
Forfeited	(337)	23.37	(115)	14.06	(37)	14.37
Outstanding at end of year	4,347	$13.16	3,667	$20.30	2,749	$12.11
Options exercisable at year-end	1,491	$12.06	1,084	$13.32	1,708	$11.07
Weighted-average fair value of options granted during the year	$6.41		$10.12		$5.39	

The following table summarizes information about stock options outstanding at December 31, 2002 (share amounts in thousands):

Range of Exercise Price	Number Outstanding at 12/31/02	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 12/31/02	Weighted Average Exercise Price
$ 3.79 — $ 9.54	556	1.9	$ 7.03	478	$ 6.81
10.29 — 12.79	764	8.0	12.21	154	11.09
13.92 — 13.92	1,000	8.4	13.92	—	—
14.35 — 14.37	934	3.8	14.36	169	14.36
14.50 — 16.11	1,093	4.0	15.22	690	15.34
$ 3.79 — $16.11	4,347	5.4	$13.16	1,491	$12.06

Share Grant

In May 2001, an officer was granted the right to receive an amount, payable in our common stock, equal to the excess of the "fair market value" (as defined in our 2001 plan) of a share of common stock on the effective date and $22.00, multiplied by one million. On the effective date, May 8, 2001, the closing price of our common stock was $23.00 and accordingly, the employee will receive $1.0 million, to be paid in five annual installments as of each anniversary of the effective date, in the form of a direct grant of shares of common stock. The number of shares is determined by dividing the annual installment by the fair market value of a share on the applicable anniversary date. We will recognize $1.0 million of noncash compensation expense ratably over the five-year period. General and administrative expense includes $0.3 million of noncash compensation expense in each of 2002 and 2001 with respect to this grant.

Restricted Stock Awards

During 2002 certain officers were granted awards totaling 180,000 restricted shares of our common stock which will vest in three equal annual installments beginning on the first anniversary of the date of grant. General and administrative expense for 2002 includes $0.3 million of noncash compensation expense with respect to these share grants.

In March 2003 our officers and directors were granted awards totaling 141,500 restricted shares of our common stock. With respect to 40,000 of such shares, vesting will occur in two equal annual installments beginning on the first anniversary of the effective date of the grant. The remaining 101,500 restricted shares will vest at the end of three years from the effective date of the grant. If after eighteen months from the date of grant our common stock trades 50% higher than the grant price for thirty consecutive trading days, the 101,500 restricted shares will vest immediately.

Note 16 — Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

Historically, we leased certain real property, equipment and operating facilities under various operating leases. Prior to the spin-off substantially all of such leases were transferred to PXP. Our future non-cancelable commitments under operating leases at December 31, 2002, which relate to certain real property, are as follows: 2003 — $22,000; 2004 — $23,000; 2005 — $23,000; and 2006 — $6,000. Total expenses related to operating lease commitments for the years ended December 31, 2002, 2001 and 2000 were $0.7 million, $0.7 million and $7.3 million, respectively. Such amounts for 2000 include $6.7 million attributable to PAA.

Although we obtained environmental studies on our properties in Florida and we believe that such properties have been operated in accordance with standard oil field practices, current or future local, state and federal environmental laws and regulations may require substantial expenditures to comply with such rules and regulations

Consistent with normal industry practices, substantially all of our oil and gas leases require that, upon termination of economic production, the working interest owners plug and abandon non-producing wellbores, remove tanks, production equipment and flow lines and restore the wellsite. We have estimated that the costs to perform these tasks is approximately $9.0 million, net of salvage value and other considerations. For valuation and realization purposes of the affected oil and gas properties, these estimated future costs are also deducted from estimated future gross revenues to arrive at the estimated future net revenues and the Standardized Measure disclosed in Note 20. As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and gas properties and the marketing, transportation, terminalling and storage of oil. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil operations and derivative instruments related to our hedging activities. PAA is the exclusive marketer/purchaser for all of our equity oil production. This concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that PAA may be affected by changes in economic, industry or other conditions. We do not believe the loss of PAA as the exclusive purchaser of our equity production would have a material adverse affect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions

There are a limited number of alternative methods of transportation for our production. Substantially all of our oil and gas production is transported by pipelines, trucks and barges owned by third parties. The inability or unwillingness of these parties to provide transportation services to us for a reasonable fee could result in our having to find transportation alternatives, increased transportation costs or involuntary curtailment of a significant portion of our oil and gas production which could have a negative impact on future results of operations or cash flows.

Note 17 — Litigation

On September 18, 2002 Stocker Resources Inc., or Stocker, the general partner of PXP before it was converted from a limited partnership to a corporation, filed a declaratory judgment action against Commonwealth Energy Corporation, or Commonwealth, in the Superior Court of Orange County, California relating to the termination of an electric service contract. Stocker is seeking a declaratory judgment that it was entitled to terminate the contract and that Commonwealth has no basis for proceeding against Stocker's related $1.5 million performance bond. Also on September 18, 2002, Stocker was named a defendant in an action brought by Commonwealth in the Superior Court of Orange County, California for breach of the electric service contract. Commonwealth is seeking unspecified damages. Stocker was merged into us in December 2002. Under our master separation agreement with PXP, we are indemnified for damages we incur as a result of this action. We intend to defend our rights vigorously in this matter.

We, in the ordinary course of business, are a claimant and/or defendant in various other legal proceedings. We do not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Note 18 — Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, Disclosures About Fair Value of Financial Instruments ("SFAS 107"). The estimated fair value amounts have been determined using available market information and valuation methodologies described below. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. Derivative financial instruments are stated at fair value. The carrying amounts and fair values of our other financial instruments are as follows (in thousands):

	December 31,			
	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt:				
Bank debt	$45,000	$45,000	$ 11,500	$ 11,500
Subordinated debt	—	—	269,539	272,130
Other long-term debt	—	—	1,022	1,022

The carrying value of bank debt approximates its fair value, as interest rates are variable, based on prevailing market rates. The fair value of subordinated debt is based on quoted market prices based on trades of subordinated debt.

Note 19 — Supplemental Disclosures of Cash Flow Information

Selected cash payments and noncash activities were as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Cash paid for interest (net of amount capitalized)	$25,129	$27,939	$56,154
Cash paid for taxes	$ 4,282	$ 7,048	$ 987
Noncash sources and (uses) of investing and financing activities:			
Tax benefit from exercise of employee stock options	$ 2,248	$ 6,990	$ 1,901

Note 20 — Oil and Gas Activities

Costs Incurred

Our oil and gas acquisition, exploration, exploitation and development activities are conducted in the United States. The following table summarizes the costs incurred during the last three years (in thousands).

	Year Ended December 31,		
	2002	2001	2000
Property acquisitions costs:			
Proved properties	$ —	$ 153	$ 480
Exploration costs	—	43	579
Exploitation and development costs	5,860	10,526	9,364
	$5,860	$10,722	$10,423

Costs incurred for discontinued operations for the years ended December 31, 2002, 2001 and 2000 was $64.5 million, $125.8 million and $70.5 million, respectively.

Capitalized Costs

The following table presents the aggregate capitalized costs subject to amortization relating to our oil and gas acquisition, exploration, exploitation and development activities, and the aggregate related accumulated DD&A (in thousands).

	December 31,	
	2002	2001
Proved properties	$ 349,517	$ 339,864
Accumulated DD&A	(299,187)	(295,472)
	$ 50,330	$ 44,392

The DD&A rate per equivalent unit of production was $3.73, $2.74 and $1.56 for the years ended December 31, 2002, 2001, and 2000, respectively.

Capitalized costs for discontinued operations at December 31, 2002 and 2001 was $462.2 million and $421.2 million, respectively.

Costs Not Subject to Amortization

The following table summarizes the categories of costs comprising the amount of unproved properties not subject to amortization (in thousands).

	December 31,		
	2002	2001	2000
Acquisition costs	$—	$2,515	$2,997
Exploration costs	—	3,579	4,031
Capitalized interest	—	1,042	816
	$—	$7,136	$7,844

During 2001 and 2000, we capitalized $0.5 million and $0.6 million, respectively, of interest related to the costs of unproved properties in the process of development.

Costs not subject to amortization for discontinued operations at December 31, 2002, 2001 and 2000 was $30.0 million, $33.4 million and $34.7 million, respectively.

Results of Operations for Oil and Gas Producing Activities

The results of operations from oil and gas producing activities below exclude non-oil and gas revenues, general and administrative expenses, interest charges, interest income and interest capitalized. Income tax (expense) or benefit was determined by applying the statutory rates to pretax operating results (in thousands).

	Year Ended December 31,		
	2002	2001	2000
Revenues from oil and gas producing activities	$18,662	$16,030	$10,643
Production costs	(6,536)	(7,397)	(5,912)
Oil transportation expenses	(3,775)	(4,449)	(3,752)
Depreciation, depletion and amortization	(3,239)	(3,302)	(2,151)
Income tax (expense) benefit	(1,971)	(353)	370
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 3,141	$ 529	$ (802)

The results of operations from discontinued oil and gas producing activities for the years ended December 31, 2002, 2001 and 2000 was $49.2 million, $71.6 million and $42.8 million, respectively.

Supplemental Reserve Information (Unaudited)

The following information summarizes our net proved reserves of oil (including condensate and gas liquids) and gas and the present values thereof for the three years ended December 31, 2002. The following reserve information is based upon reports of the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. The estimates are in accordance with regulations prescribed by the SEC.

We believe the reserve estimates presented herein, in accordance with generally accepted engineering and evaluation principles consistently applied, are reasonable. However, there are numerous uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and gas that cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because all reserve estimates are to some degree speculative, the quantities of oil and gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and gas sales prices may all differ from those assumed in these estimates. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data. Therefore, the Standardized Measure shown below represents estimates only and should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. In this regard, the information set forth in the following tables includes revisions of reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent exploitation and development activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices.

Decreases in the prices of oil have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenues, profitability and cash flow. All of our reserves are comprised of oil properties that are sensitive to oil price volatility.

Estimated Quantities of Oil Reserves (Unaudited)

The following table sets forth certain data pertaining to our proved and proved developed reserves for the three years ended December 31, 2002 (in thousands).

	As of or for the Year Ended December 31,		
	2002	2001	2000
		Oil (MBbls)	
Proved Reserves			
Beginning balance	17,343	18,775	23,709
Revision of previous estimates	(60)	(2,470)	(4,092)
Extensions, discoveries, improved recovery and other additions	—	1,992	—
Production	(970)	(954)	(842)
Ending balance	16,313	17,343	18,775
Proved Developed Reserves			
Beginning balance	15,456	17,853	19,383
Ending balance	14,499	15,456	17,853

Proved oil and gas reserves for discontinued operations totaled 240.2 MMBbls of oil and 77.1 Bcf of gas at December 31, 2002; 223.3 MMBbls of oil and 96.2 Bcf of gas at December 31, 2001, and 204.4 MMBbls of oil and 93.5 Bcf of gas at December 31, 2000.

Standardized Measure of Discounted Future Net Cash Flows (Unaudited)

The Standardized Measure of discounted future net cash flows relating to proved oil reserves is presented below (in thousands):

	December 31, 2002	2001	2000
Future cash inflows	$ 330,377	$ 171,319	$ 207,129
Future development costs	(30,992)	(24,131)	(26,543)
Future production expense	(151,539)	(112,503)	(126,809)
Future income tax expense	(27,136)	—	—
Future net cash flows	120,710	34,685	53,777
Discounted at 10% per year	(47,371)	(8,140)	(12,567)
Standardized measure of discounted future net cash flows	$ 73,339	$ 26,545	$ 41,210

The Standardized Measure of discounted future net cash flows related to discontinued operations at December 31, 2002, 2001 and 2000 was $883.5 million, $384.5 million and $789.4 million, respectively.

The Standardized Measure of discounted future net cash flows (discounted at 10%) from production of proved reserves was developed as follows:

1. An estimate was made of the quantity of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.

2. In accordance with SEC guidelines, the engineers' estimates of future net revenues from our proved properties and the present value thereof are made using oil sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations. We have entered into various arrangements to fix or limit the NYMEX oil price for a significant portion of our oil production. Arrangements in effect at December 31, 2002 are discussed in Note 3. Such arrangements are not reflected in the reserve reports. The overall average year-end realized price used in the reserve reports as of December 31, 2002, was $20.25 per barrel of oil. Such price as of December 31, 2001 was $9.82 per barrel of oil.

3. The future gross revenue streams were reduced by estimated future operating costs (including production and ad valorem taxes) and future development and abandonment costs, all of which were based on current costs.

4. The reports reflect the pre-tax Present Value of Proved Reserves to be $87.9 million, $26.5 million and $41.2 million at December 31, 2002, 2001 and 2000, respectively. SFAS No. 69 requires us to further reduce these estimates by an amount equal to the present value of estimated income taxes which might be payable by us in future years to arrive at the Standardized Measure. Future income taxes were calculated by applying the statutory federal and state income tax rate to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to oil operations.

The principal sources of changes in the Standardized Measure of the future net cash flows for the three years ended December 31, 2002, are as follows (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Balance, beginning of year	$ 26,545	$ 41,210	$ 134,380
Sales, net of production expenses	(8,964)	(5,355)	(7,549)
Net change in sales and transfer prices, net of production expenses	77,743	(16,188)	(95,420)
Changes in estimated future development costs	(3,185)	1,374	2,094
Extensions, discoveries and improved recovery, net of costs	—	5,768	—
Previously estimated development costs incurred during the year	915	840	3,508
Revision of quantity estimates and timing of estimated production	(8,125)	(6,239)	(15,629)
Accretion of discount	2,986	5,135	14,515
Net change in income taxes	(14,576)	—	5,311
Balance, end of year	$ 73,339	$ 26,545	$ 41,210

Note 21 — Quarterly Financial Data (Unaudited)

As a result of the spin-off, the historical results of operations of PXP are reflected as discontinued operations. The following table shows summary financial data for 2002 and 2001 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2002					
Revenues	$ 4,056	$ 4,659	$ 5,151	$ 4,796	$ 18,662
Costs and expenses	5,261	5,196	4,950	4,790	20,197
Operating profit (loss)	(1,205)	(537)	201	6	(1,535)
Equity in earnings of PAA	4,350	5,256	4,454	4,747	18,807
Gains on PAA unit transactions and public offerings	—	—	14,512	—	14,512
Income from continuing operations	732	1,456	3,767	3,777	9,732
Income from discontinued operations	5,864	8,218	7,418	6,300	27,800
Net income	6,596	9,674	11,185	10,077	37,532
Cumulative preferred dividends	(350)	(350)	(350)	(350)	(1,400)
Income available to common stockholders	6,246	9,324	10,835	9,727	36,132
Basic EPS					
Continuing operations	0.02	0.05	0.14	0.14	0.35
Discontinued operations	0.25	0.34	0.31	0.26	1.16
Net income	0.27	0.39	0.45	0.40	1.51
Diluted EPS					
Continuing operations	0.02	0.04	0.14	0.14	0.34
Discontinued operations	0.24	0.33	0.30	0.26	1.14
Net income	0.26	0.37	0.44	0.40	1.48

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2001					
Revenues	$ 5,566	$ 2,873	$ 4,572	$ 3,019	$ 16,030
Costs and expenses	6,647	12,675	4,017	4,406	27,745
Operating profit (loss)	(1,081)	(9,802)	555	(1,387)	(11,715)
Equity in earnings of PAA	6,836	3,755	5,207	2,742	18,540
Gains on PAA unit transactions and public offerings	1,958	148,213	918	19,068	170,157
Income from continuing operations	3,379	83,022	2,686	11,537	100,624
Income from discontinued operations	17,573	17,080	12,468	7,572	54,693
Income before cumulative effect of accounting change	20,952	100,102	15,154	19,109	155,317
Cumulative effect of accounting change	(1,986)	—	—	—	(1,986)
Cumulative preferred dividends	(1,599)	(24,947)	(350)	(349)	(27,245)
Income available to common stockholders	17,367	75,155	14,804	18,760	126,086
Basic EPS					
Continuing operations	0.10	2.96	0.10	0.47	3.48
Discontinued operations	1.01	0.87	0.53	0.32	2.59
Cumulative effect of accounting change	(0.11)	—	—	—	(0.09)
Net income	1.00	3.83	0.63	0.79	5.98
Diluted EPS					
Continuing operations	0.07	2.08	0.10	0.45	2.81
Discontinued operations	0.73	0.60	0.48	0.30	2.01
Cumulative effect of accounting change	(0.07)	—	—	—	(0.07)
Net income	0.73	2.68	0.58	0.75	4.75

Note 22 — Operating Segments

Prior to completion of the Transactions, our operations consisted of two operating segments: (1) Upstream Operations — engages in the acquisition, exploitation, development, exploration and production of oil and gas and (2) Midstream Operations — engages in pipeline transportation, purchases and resales of oil at various points along the distribution chain and the leasing of certain terminalling and storage assets. As a result of the Transactions we no longer have a Midstream segment.

	Upstream	Midstream	Total
		(In thousands)	
2000			
Revenues:			
External customers	$149,342	$6,425,644	$6,574,986
Intersegment(a)	—	215,543	215,543
Gain on sale of assets	—	48,188	48,188
Interest and other income (expense)	(3,468)	10,879	7,411
Total revenues of reportable segments	$145,874	$6,700,254	$6,846,128
Segment gross margin(b)	$ 86,202	$ 126,066	$ 212,268
Segment gross profit(c)	76,297	85,195	161,492
Segment income (loss) before income taxes, extraordinary item and cumulative effect of accounting change	23,009	91,033	114,042
Interest expense	27,346	28,482	55,828
Depreciation, depletion and amortization	22,474	24,747	47,221
Income tax expense	6,503	19,080	25,583
Extraordinary item, net of tax and minority interest	—	(4,988)	(4,988)
Capital expenditures	81,475	12,603	94,078
Assets	458,678	935,651	1,394,329

(a) Intersegment revenues and transfers were conducted on an arm's-length basis.

(b) Gross margin is calculated as operating revenues less operating expenses.

(c) Gross profit is calculated as operating revenues less operating expenses and general and administrative expenses.

The following table reconciles segment revenues to amounts reported in our financial statements for the year ended December 31, 2000 (in thousands):

Revenues of reportable segments	$6,846,128
Intersegment	(215,543)
Net gain recorded upon the formation of PAA not allocated to reportable segments	—
Total company revenues	$6,630,585

PAA is the exclusive purchaser of all of our equity oil production. The following table reflects for the year ended December 31, 2000, during which period PAA was included in our consolidated financial statements, customers accounting for more than 10% of consolidated sales (excluding hedging effects):

Customer	Percentage of Consolidated Sales
Marathon Ashland Petroleum(1)	12%
	Percentage of Oil Sales(2)
Conoco Inc.	55%
ExxonMobil	33%

(1) These customers pertain to our midstream segment Represents percentage of oil and gas sales revenues plus marketing, transportation, storage and terminalling revenues.

(2) These percentages represent the entities that purchased our equity oil production from PAA.

We do not believe the loss of PAA as the exclusive purchaser of our equity production would have a material adverse effect on our results of operations. We believe PAA could be replaced by other purchasers under contracts with similar terms and conditions.

CORPORATE INFORMATION

DIRECTORS

James C. Flores
Chairman of the Board
Plains Resources Inc.

William M. Hitchcock
President
Pembroke Capital, LLC

D. Martin Phillips
Managing Director and Principal
Encap Investments L.L.C.

Robert V. Sinnott
Vice President
Kayne Anderson Investment Management, Inc.
Director—Plains All American GP LLC

J. Taft Symonds
Chairman of the Board
Tetra Technologies, Inc.
Director—Plains All American GP LLC

OFFICERS

James C. Flores
Chairman of the Board

John T. Raymond
Chief Executive Officer and President
Director—Plains All American GP LLC

Stephen A. Thorington
Executive Vice President and
Chief Financial Officer

Franklin R. Bay
Sr. Vice President of Corporate Development
Chief Legal Officer and Secretary

TRANSFER AGENT

American Stock Transfer & Trust
59 Maiden Lane, Plaza Level
New York, New York 10038

FORM 10-K

A copy of the Company's annual report on Form 10-K to the Securities and Exchange Commission for the year ended December 31, 2002, is available free of charge on request to:

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STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements based on our current expectations and projections about future events. Statements that are predictive in nature, that depend upon or refer to future events or conditions, or that include words such as "will," "would," "should," "plans," "likely," "expects," "anticipates," "intends," "believes," "estimates," "thinks," "may," and similar expressions, are forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause our actual results and performance to be materially different from any future results or performance expressed or implied by these forward-looking statements. These factors include, among other things:

- the consequences of any potential change in the relationship between us and Plains Exploration & Production Company;
- the consequences of our and Plains Exploration's officers and employees providing services to both us and Plains Exploration and not being required to spend any specified percentage or amount of time on our business;
- risks, uncertainties and other factors that could have an impact on Plains All American Pipeline, L.P. ("PAA"), which could in turn impact the value of our holdings in PAA (for a discussion of these risks, uncertainties and other factors, see PAA's filings with the SEC);
- the effects of our indebtedness, which could adversely restrict our ability to operate, could make us vulnerable to general adverse economic and industry conditions, could place us at a competitive disadvantage compared to our competitors that have less debt, and could have other adverse consequences;
- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations;
- the effects of competition;
- the success of our risk management activities;
- the availability (or lack thereof) of acquisition or combination opportunities;
- the impact of current and future laws and governmental regulations;
- environmental liabilities that are not covered by an effective indemnity or insurance, and
- general economic, market, industry or business conditions.

All forward-looking statements in this report are made as of the date hereof, and you should not place undue certainty on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report. Moreover, although we believe the expectations reflected in the forward-looking statements are based upon reasonable assumptions, we can give no assurance that we will attain these expectations or that any deviations will not be material. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information. **[See Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results" in this report for an additional discussion of risks and uncertainties.]**

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