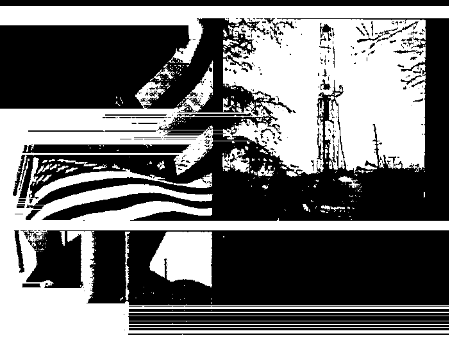
Report 2002

PLAINS EXPLORATION & PRODUCTION COMPANY

PXP



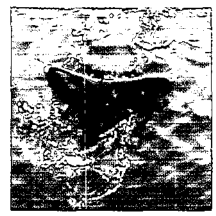
POSITIONED
FOR THE FUTURE

CORPORATE PROFILE

Plains Exploration & Production Company (NYSE:PXP) is headquartered in Houston, Texas and is actively involved in the upstream sector of the energy industry.

We are an independent oil and gas company primarily engaged in the upstream activities of acquiring, exploiting, developing and producing oil and gas in the United States. Our core areas of operation are onshore California, primarily in the Los Angeles Basin, offshore California in the Point Arguello unit and the Illinois Basin in southern Illinois and Indiana.

We own a 100% working interest in and operate all of our properties, except for offshore California, in which we own a 52.6% working interest and where we are the operator. Our oil and gas properties are generally mature but underdeveloped, have produced significant volumes since initial discovery and have significant estimated remaining reserves. We opportunistically hedge portions of our oil production to manage our exposure to commodity price risk.

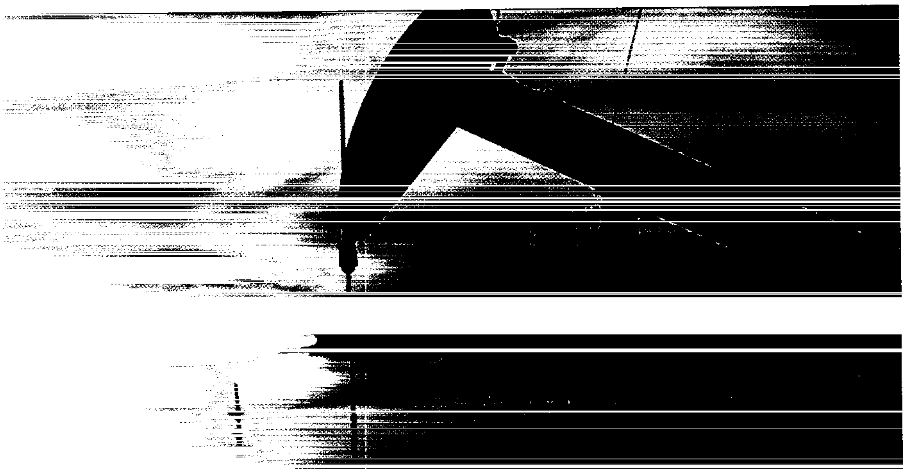
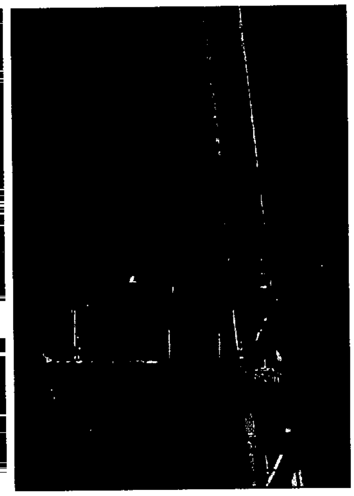
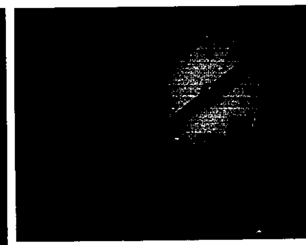
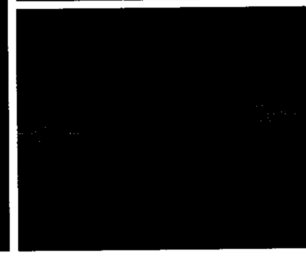


THE OCEAN (OFF VANDENBERG AFB) WAS UNBELIEVABLY CALM FOR THIS AREA, AND THE HUMP-BACK WHALES WERE COMING RIGHT UP TO THE PLATFORM REPEATEDLY. MARINE LIFE EXISTS NEAR OUR PLATFORMS, WHICH HAVE BEEN IN THIS AREA FOR MORE THAN 15 YEARS.

TO OUR SHAREHOLDERS:

Plains Exploration & Production Company (PXP) began its independent, corporate life on December 18, 2002. On that date, the tax-free spin off of PXP to the shareholders of our former parent, Plains Resources Inc. (PLX), was completed. This was the landmark event for the Company last year. The separation of the upstream business, PXP, from the midstream business, PLX, will allow both businesses to prosper under separate corporate and capital allocation strategies that solely reflect their individual businesses. The following letter will refer to PXP on a pro forma 2002 basis.

Throughout 2002, PXP delivered good operational performance by establishing record production and reserve volumes for the Company. We produced approximately 9.3 million barrels of oil equivalents (BOEs) during 2002 and reported proved reserves net to the Company of 253 million BOEs at December 31, 2002. These results represented an increase of 6% in both annual production and proved reserves. We will be active with development and production work on our assets both in California and Illinois during 2003 aimed at producing profitable oil and gas for our shareholders. We believe these operations have positioned PXP for future growth and value creation. We have long-lived production assets with a large, low risk, multi-year development inventory that we believe continues to generate attractive rates of return and cash flow. Your management will judiciously deploy this cash flow with a goal to continue growing production and reserves profitably. The most dynamic project that PXP will undertake in 2003 is the 3-D Seismic imaging of the deep sands of our prolific Inglewood Field in California. This is expected to position the large structure at Inglewood for development of its multiple reservoirs below 3,500 feet. The Inglewood Deep 3-D Seismic survey should image the prolific Miocene Sands below the Vickers/Ringe main field pays, which we believe will unlock additional potential drilling sites for development.

Net income for the year totaled $26.2 million or $1.08 per share compared to net income of $53.2 million or $2.20 per share in 2001. Results for 2002 included special charges related to the spin off from PLX of approximately $6.8 million. Unit gross margin was $11.76 per barrel equivalent in 2002 with crude oil prices averaging $20.27 per barrel and natural gas prices averaging $3.06 per Mcf during the year. We continue our commitment to hedge commodity price risk. Our 2003 hedge position consists of 19,250 barrels per day swapped at an average NYMEX price of $23.81. In 2004 we have hedged 17,500 barrels per day with swaps at an average NYMEX price of $23.82. And for 2005 we have hedged 5,000 barrels per day with swaps at an average NYMEX price of $23.57 per barrel. These NYMEX prices are before location and quality differentials.

PXP is blessed with dedicated and dynamic employees that are technically proficient, innovative and always striving for value creation for our shareholders. Plains Exploration & Production Company is well positioned and looks forward to a prosperous 2003. Thank you for your continued support.

James C. Flores
Chairman and Chief Executive Officer

FINANCIAL HIGHLIGHTS

(In thousands, except per share & percentage information)	**2002**	2001	2000	1999	1998
RESERVE DATA:					
Total oil reserves (barrels)	**240,161**	223,293	204,387	195,213	110,951
Total gas reserves (Mcf)	**77,154**	96,217	93,486	90,873	86,781
Total barrels of oil equivalent (BOE)	**253,020**	239,329	219,968	210,359	125,415
Percentage proved developed volume	**54%**	54%	52%	52%	62%
Estimated future net revenue[1]	**$3,859,739**	$1,642,744	$2,852,404	$2,637,436	$439,296
Present value at 10% of estimated future net revenue[1]	**$1,515,044**	$ 643,220	$1,304,182	$1,106,358	$225,331
Percentage proved developed present value	**60%**	71%	75%	57%	86%
OPERATING DATA:					
Oil production (barrels)	**8,783**	8,219	7,654	7,081	5,821
Average oil price (per barrel)	**$ 20.27**	$ 21.28	$ 16.52	$ 14.46	$ 13.99
Gas production (Mcf)	**3,362**	3,355	3,042	3,163	3,101
Average gas price (per Mcf)	**$ 3.06**	$ 8.58	$ 5.26	$ 1.61	$ 1.36
BOE production	**9,343**	8,778	8,161	7,608	6,321
Average BOE price	**$ 20.16**	$ 23.20	$ 17.46	$ 14.13	$ 13.53
Production expense per BOE	**$ 8.40**	$ 7.27	$ 6.89	$ 6.64	$ 6.77
Gross margin per BOE	**$ 11.76**	$ 15.93	$ 10.57	$ 7.49	$ 6.76
SELECTED FINANCIAL DATA:					
Total revenue	**$ 188,563**	$ 204,139	$ 142,451	$ 107,485	$ 85,507
Operating income (loss)	**$ 64,567**	$ 106,029	$ 61,056	$ 39,262	$ (17,355)[2]
Income (loss) before cumulative effect of accounting change	**$ 26,237**	$ 54,693	$ 28,749	$ 19,105	$ (19,034)
Cumulative effect of accounting change, net of tax	**$ —**	$ (1,522)	$ —	$ —	$ —
Net income (loss)	**$ 26,237**	$ 53,171	$ 28,749	$ 19,105	$ (19,034)
Income (loss) per share					
Before cumulative effect of accounting change	**$ 1.08**	$ 2.26	$ 1.19	$ 0.79	$ (0.79)
Cumulative effect of accounting change	**$ —**	$ (0.06)	$ —	$ —	$ —
Net income (loss)	**$ 1.08**	$ 2.20	$ 1.19	$ 0.79	$ (0.79)
Weighted average shares outstanding					
Basic	**24,193**	24,200	24,200	24,200	24,200
Diluted	**24,201**	24,200	24,200	24,200	24,200
Total assets	**$ 550,880**	$ 516,755	$ 401,035	$ 360,964	$277,792
Long-term debt/payable to Plains Resources	**$ 233,166**	$ 236,183	$ 226,529	$ 239,661	$179,972
Total stockholders' equity	**$ 173,820**	$ 180,087	$ 111,032	$ 82,283	$ 63,177

(1) Before deducting estimated future income taxes

(2) After deducting $42,920 noncash charge related to a ceiling test write-down of the capitalized costs of our proved oil and gas properties due to low oil prices at December 31, 1998

WE MANAGE THE COMPANY WITH THE CORE BELIEF THAT SUCCESS NEVER COMES AT THE EXPENSE OF INTEGRITY.

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(d) 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: 001-31470

PLAINS EXPLORATION & PRODUCTION COMPANY
(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**33-0430755** **(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 $0.01 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 whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ☐ No ☑

On March 25, 2003, there were 24,225,075 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 $199,380,000 on March 25, 2003 (based on $8.68 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date). (1)

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.

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. ☐

(1) Because the registrant's common stock became registered under Section 12(b) of the Securities Exchange Act of 1934 on December 6, 2002, the registrant has provided the aggregate market value information as of a recent date rather than as of the most recently completed second fiscal quarter.

PLAINS EXPLORATION & PRODUCTION COMPANY

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 in 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 Resources;
- the consequences of our officers and employees providing services to both us and Plains Resources and not being required to spend any specific percentage or amount of time on our business;
- uncertainties inherent in the development and production of and exploration for 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 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;
- 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 or business conditions.

All forward-looking statements in this Annual Report on Form 10-K 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 addressed in this Annual Report on Form 10-K. 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. 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" for an additional discussion of these 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.plainsxp.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 (under "Investor Information" on 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 barrels 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.

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.

MMBtu. One million British Thermal units. One British thermal unit is the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

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 crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, 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) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (iii) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (iv) crude oil, natural gas, and natural 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 are 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.

Items 1 and 2. *Business and Properties.*

General

We are an independent oil and gas company primarily engaged in the upstream activities of acquiring, exploiting, developing and producing oil and gas in the United States. Our core areas of operation are:

- onshore California, primarily in the LA Basin;
- offshore California in the Point Arguello unit; and
- the Illinois Basin in southern Illinois and Indiana.

Our strategy is to continue to grow our cash flow from operations and to use this cash flow to increase our proved developed reserves and production, acquire additional underdeveloped oil and gas properties and make other strategic acquisitions. We focus on implementing improved production practices and recovery techniques, and relatively low-risk development drilling. We believe we can continue our strong reserve and production growth through the exploitation and development of our existing inventory of projects relating to our properties. We also intend to be opportunistic in pursuing selective acquisitions of oil or gas properties or exploration projects. We will consider opportunities located in our current core areas of operation as well as projects in other areas in North America that meet our investment criteria.

Corporate Reorganization and Spin-off

Prior to December 18, 2002 we were a wholly owned subsidiary of Plains Resources Inc., or Plains Resources. On December 18, 2002 Plains Resources distributed 100% of the issued and outstanding shares of our common stock to the holders of record of Plains Resources' common stock as of December 11, 2002. Each Plains Resources stockholder received one share of our common stock for each share of Plains Resources common stock held. Prior to the spin-off, Plains Resources made an aggregate of $52.2 million in cash contributions to us and transferred to us certain assets and we assumed certain liabilities of Plains Resources, primarily related to land, unproved oil and gas properties, office equipment and pension obligations. We used the cash contributions to reduce outstanding debt under our revolving credit facility.

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

Plains Resources received a favorable private letter ruling from the Internal Revenue Service 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. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Proposed Merger

On February 3, 2003 we announced that we entered into a definitive agreement pursuant to which we will acquire 3TEC Energy Corporation, or 3TEC, for approximately $333.0 million plus the assumption of debt, which totaled $99.0 million at December 31, 2002. Under the terms of the merger agreement, 3TEC common stockholders will receive $8.50 of cash and 0.85 of a share of our common stock for each share of 3TEC common stock they own, which equates to a total of $16.97 per 3TEC common share based on the January 31, 2003 closing price of $9.96 per share for our common stock. This exchange ratio is subject to an upward or downward adjustment should the market price of our common stock fall below $7.65 per share or rise above $12.35 per share, respectively. This mechanism is intended to provide that the total value of the consideration received by 3TEC common stockholders at the effective time of the merger will be between $15.00 and $19.00 per share of 3TEC common stock. For this purpose, the market price of our common stock will be the average closing price of our common stock for the 20 consecutive trading days immediately preceding the third trading day prior to closing. In addition, if the market price of our common stock is less than $6.25, we may either (i) terminate the merger agreement or (ii) in lieu of issuing more common stock increase the cash consideration paid per share of 3TEC common stock by the amount our common stock market price is less than $6.25 times the exchange ratio after adjustment.

The merger is expected to qualify as a tax free reorganization under Section 368(a) of the Internal Revenue Code. Accordingly, the merger is expected to be tax free to our stockholders and tax free for the stock portion of the consideration received by 3TEC stockholders. We anticipate funding the cash portion of the merger through a new credit facility.

The Boards of Directors of both companies have approved the merger agreement and each has recommended it to their respective stockholders for approval. The transaction is subject to stockholder approval from both companies and other customary conditions and is expected to close in the second quarter of 2003. Assuming the market price of our common stock is between $7.65 and $12.35, after the merger is completed, 3TEC common stockholders will own approximately 40% of the combined company and our stockholders will own approximately 60% of the combined company.

Oil and Gas Operations

We own a 100% working interest in and operate all of our properties, except for offshore California, where we own a 52.6% working interest and where we are the operator. As a result, we benefit from economies of scale and control the level, timing and allocation of substantially all of our capital expenditures and expenses. Our reserves are generally mature but underdeveloped, have produced significant volumes since initial discovery and have significant estimated remaining reserves

We have a large inventory of projects in our core areas that we believe will support at least five years of exploitation and development activity. Over the last three years, we have achieved a high success rate on these types of projects, drilling a total of 407 development wells with a 99% success rate. In addition, we have completed numerous other production enhancement projects, such as recompletions, workovers and upgrades. The results of these activities over the last three years have been additions to proved reserves, excluding reserves added through acquisition activities, totaling 67.7 MMBOE, or approximately 257% of cumulative net production for this period. Reserve replacement costs, excluding acquisitions, have averaged approximately $3.86 per BOE for the same period.

We actively manage our exposure to commodity price fluctuations by hedging significant portions of our oil production through the use of swaps, collars and purchased puts and calls. The level of our hedging activity depends on our view of market conditions, available hedge prices and our operating strategy. Under our hedging program, we typically hedge approximately 70-75% of our production for the current year, 40-50% of our production for the next year and up to 25% of our production for the following year. For example, assuming estimated fourth quarter 2002 production levels are held constant in subsequent periods, as of March 1, 2003 we had hedged approximately 75% of our oil production for 2003, approximately 69% of our oil production for 2004 and approximately 20% of our oil production for 2005.

We had estimated total proved reserves of 253.0 MMBOE as of December 31, 2002, of which 95% was comprised of oil and 54% was proved developed. We have a reserve life of over 27 years and a proved developed reserve life of over 14 years. We believe our long-lived, low production decline reserve base combined with our active hedging strategy should provide us with relatively stable and recurring cash flow. As of December 31, 2002 and based on year-end 2002 spot market prices of $31.20 per Bbl of oil and $4.79 per MMBtu of gas, our reserves had a PV-10 of $1.5 billion and a standardized measure of $883.5 million.

The following table sets forth information with respect to our oil and gas properties as of and for the year ended December 31, 2002 (dollars in millions):

	Onshore California	Offshore California	Illinois Basin	Total
Proved reserves				
MMBOE	223.2	4.2	25.6	253.0
Percent oil	94%	98%	100%	95%
Proved Developed Reserves—MMBOE	116.5	3.9	15.9	136.3
2002 Production—MMBOE	6.6	1.8	0.9	9.3
PV-10(1)	$1,387.2	$21.3	$106.5	$1,515.0
Standardized measure(2)				$ 883.5

(1) Based on year-end 2002 spot market prices of $31.20 per Bbl of oil and $4.79 per MMBtu of gas. PV-10 represents the standardized measure before deducting estimated future income taxes.
(2) Estimated future income taxes are calculated on a combined basis using the statutory income tax rate, accordingly, the standardized measure is presented in total only.

During the three-year period ended December 31, 2002 we drilled 407 development wells, 403 of which were successful. During this period, we incurred aggregate oil and gas acquisition, exploitation, development and exploration costs of $260.8 million, resulting in proved reserve additions of 70.3 MMBOE, at an average reserve replacement cost of $3.71 per BOE, which we believe to be among the lowest of our peer group. During that three-year period approximately 99% of our oil and gas capital expenditures were for acquisition, exploitation and development activities.

Oil and Gas Reserves

The following table sets forth certain information with respect to our reserves based upon reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott Company in 2002 and 2001, and H.J. Gruy and Associates, Inc., Netherland, Sewell & Associates, Inc. and Ryder Scott Company in 2000. The reserve volumes and values were determined under the method prescribed by the SEC, which requires the application of year-end prices for each year, held constant throughout the projected reserve life.

	As of or for the Year Ended December 31,		
	2002	2001	2000
	(dollars in thousands)		
Oil and Gas Reserves			
Oil (MBbls)			
Proved developed	127,415	119,248	105,679
Proved undeveloped	112,746	104,045	98,708
	240,161	223,293	204,387
Gas (MMcf)			
Proved developed	53,317	59,101	52,184
Proved undeveloped	23,837	37,116	41,302
	77,154	96,217	93,486
MBOE	253,020	239,329	219,968
PV-10 (1):			
Proved developed	$ 916,373	$454,095	$ 982,752
Proved undeveloped	598,671	189,125	321,430
	$1,515,044	$643,220	$1,304,182
Standardized Measure	$ 883,507	$384,467	$ 789,438
Average year-end realized prices (2)			
Oil (per Bbl)	$ 26.91	$ 15.31	$ 21.93
Gas (per Mcf)	$ 4.63	$ 2.56	$ 14.63
Year-end spot market prices			
Oil (per Bbl)	$ 31.20	$ 19.84	$ 26.80
Gas (per MMBtu)	$ 4.79	$ 2.58	$ 13.70
Reserve replacement ratio	261%	321%	218%
Reserve life (years)	27.1	27.3	27.0
Reserve replacement cost per BOE	$ 2.64	$ 4.47	$ 3.97

(1) PV-10 represents the standardized measure before deducting estimated future income taxes. Our year-end 2002 PV-10 and standardized measure include future development costs related to proved undeveloped reserves of $43.7 million in 2003, $55.6 million in 2004 and $46.6 million in 2005.

(2) Based on price in effect at year-end with adjustments based on location and quality.

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. Many of the factors that impact these estimates are beyond our control. Reservoir 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, 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 PV-10 shown above 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 accordance with SEC guidelines, the reserve engineers' estimates of future net revenues from our properties, and the present value of the properties, are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where the guidelines permit alternate treatment, including the use of fixed and determinable contractual price escalations but excluding the effect of any hedges we have in place. Historically, the prices for oil and gas have been volatile and are likely to continue to be volatile in the future. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk".

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

Exploitation and Development

Exploitation strategy. We implement our exploitation plan with respect to our properties by:

- enhancing product price realizations;
- optimizing production practices;
- realigning and expanding injection processes;
- drilling wells; and
- performing stimulations, recompletions, artificial lift upgrades and other operating margin and reserve enhancements.

After we acquire a property, we may also seek to increase our interest in the property by acquiring nearby acreage, pursuing farm-in drilling arrangements and purchasing minority interests in the property.

By implementing our exploitation plan, we seek to increase cash flows and enhance the value of our asset base. In doing so, we add to and enhance our proved reserves. During the three-year period ended December 31, 2002 our additions to proved reserves, excluding reserves added as a result of our acquisition activities, totaled 67.7 MMBOE or approximately 257% of cumulative net production for this period. We added these reserves at an aggregate average cost of $3.86 per BOE.

If the planned merger with 3TEC does not occur, during 2003 we expect to spend $70-$80 million developing, exploiting and maintaining our oil and gas properties, with approximately 80% of such expenditures allocated to our onshore California properties. Our 2003 capital program includes the drilling of approximately 175 to 190 wells. We believe that our properties hold potential for additional increases in production, reserves and cash flow.

Exploitation projects. The following table sets forth information with respect to our oil and gas properties (dollars in millions):

	Onshore California	Offshore California	Illinois Basin
Year(s) discovered	1906-1966	1981	1905
Year acquired	1992-1998	1999-2002	1995
Proved reserves at acquisition—MMBOE	68.6	9.0	17.3
Year Ended December 31, 2002			
Capital Expenditures	$ 45.4	$ 1.1(3)	$ 7.0
Sales—MMBOE	6.6	1.8	0.9
Gross Margin (1)	$ 84.1	$ 15.6	$ 10.4
As of December 31, 2002:			
Proved Reserves—MMBOE	223.2	4.2	25.6
Proved Developed Reserves—MMBOE	116.5	3.9	15.9
PV-10 (2)	$1,387.2	$ 21.3	$106.5

(1) Revenues less production costs.

(2) Based on year-end 2002 spot market prices of $31.20 per Bbl of oil and $4.79 per MMBtu of gas. PV-10 represents the standardized measure before deducting estimated future income taxes. Our standard measure at December 31, 2002 was $883.5 million.

(3) In connection with the acquisition of an additional interest in the Point Arguello field, offshore California, we assumed certain obligations of the seller. As consideration for receiving the transferred properties and assuming such obligations, we received $2.4 million. In addition, we received $2.7 million as our share of revenues less costs for the period April 1 to July 31, 2002 (the period prior to ownership).

Onshore California

LA Basin. In 1992 we acquired from ChevronTexaco (references herein to ChevronTexaco include its predecessor companies, Chevron U.S.A. Inc. and Texaco Inc. and their subsidiaries) substantially all of its producing oil properties in the LA Basin. These interests included the Inglewood, East Beverly Hills, San Vicente and South Salt Lake fields. Following the initial acquisition we expanded our holdings in this area by acquiring additional interests within the existing fields, including all of ChevronTexaco's interest in its Vickers lease, which further consolidated our holdings in the Inglewood field. We refer to all of our properties in the LA Basin acquired before 1997 collectively as the "LA Basin properties". We hold a 100% working interest in the LA Basin properties.

The LA Basin properties consist of oil reserves discovered at various times between 1924 and 1966. We have performed various exploitation activities, including drilling additional production and injection wells, returning previously marginal wells to economic production, optimizing pre-existing waterflood operations, initiating new waterfloods, optimizing artificial lift, increasing the capacity and efficiency of facilities, upgrading facilities to maintain regulatory compliance, reducing unit production expenses and improving marketing margins. Additionally, we continuously update and perform technical studies to identify new investment opportunities on these properties. Through these acquisition and exploitation activities, our net average daily production from this area has increased from approximately 6.7 MBOE per day in 1992 to 12.2 MBOE per day in 2002.

In December 1995 we amended our asset purchase agreement with ChevronTexaco to remediate sections of our LA Basin properties impacted by prior drilling and production operations. Under this agreement, ChevronTexaco agreed to investigate contamination at the LA Basin properties and potentially remediate specific areas contaminated with hazardous substances, such as volatile organic substances and heavy metals, and we agreed to excavate and remediate nonhazardous oil contaminated soils. We are obligated to construct and operate, for the next eight years, at least a five-acre parcel of land as bioremediation cells for oil contaminated soils designated for excavation and treatment by ChevronTexaco. Although we believe that we do not have any material obligations for operations conducted before our acquisition of the properties from ChevronTexaco other than our obligation to plug existing wells and those normally associated with customary oil field operations of similarly situated properties (such as our agreement with ChevronTexaco described above), these amounts may not be recoverable from ChevronTexaco, either under our agreement or the limited indemnity from ChevronTexaco contained in the original purchase agreement.

In 2002 we spent $32.3 million on capital projects, including drilling 20 production wells and four injection wells, performing numerous recompletions and workovers, and modifying various production and injection facilities. In 2003 we expect to drill 25 to 30 wells, perform workovers, stimulations and conversions, perform various technical studies including reservoir simulation, tracer surveys and reserve modeling and upgrade facilities to increase capacities and efficiencies.

We are also applying 3-D seismic technology to further evaluate the unproved reserves in our LA Basin properties, in particular at the Inglewood field. We expect to shoot a 3-D survey in 2003. Interpretation of the data should occur in 2003 and any drilling based on the results may take place in late 2003 and in 2004 and beyond. This will be the first application of 3-D seismic technology in an onshore LA Basin Field. Also in the Inglewood field, we have initiated a 20-well evaluation program using cased hole resistivity logging technology. This technology potentially identifies commercially producible sands behind casing in older wells. Furthermore, we expect these analyses to provide us with a more complete understanding of the field thereby potentially allowing us to improve the waterflood program. Finally, we anticipate the installation of an alternative to procuring electricity for a portion of the current load in the Inglewood field by installation of a cogeneration facility.

Montebello. In March 1997 we expanded our operations in the LA Basin by acquiring ChevronTexaco's interest in the Montebello field, which included a 100% working interest (99.2% net revenue interest) in 55 producing oil wells and related facilities and approximately 480 acres of surface fee land. Our net average daily production from this field has increased from 0.9 MBOE per day at the time of acquisition to 2.6 MBOE per day in 2002. Since the acquisition, we have drilled a total of 65 producing wells and 25 injection wells. In 2002 we spent $10.8 million on capital projects, which included drilling 18 production wells and 3 injection wells, performing numerous workovers, acquiring seismic and other technical data and increasing the capacity of the production and injection facilities. In 2003 we expect to perform several technical studies that may lead to additional drilling or other development opportunities that would likely be initiated beginning in 2004.

Arroyo Grande. In November 1997 we acquired a 100% working interest (94% net revenue interest) in the Arroyo Grande field located in San Luis Obispo County, California, from subsidiaries of Shell Oil Company. We also acquired surface and related development rights to approximately 1,000 acres included in the 1,500-acre producing unit. The field is primarily under continuous steam injection and, at our acquisition date, was producing approximately 1.6 MBOE per day (approximately 1.5 MBOE net to our interest) of 14 degree API gravity oil from 70 wells. Since acquiring this property, we have drilled additional wells to downsize the injection patterns in the currently developed area from five acres to one and a quarter acres to accelerate recoveries, and realigned steam injection within these areas to increase the efficiency of the recovery process. We also curtailed steam injection by about 50% immediately following the acquisition due to low oil prices. Although oil prices subsequently rebounded, we maintained injection at this low rate pending our analysis of the saturation inputs provided by the infill drilling program, and in 2001 due to excessive gas fuel costs. As a result, base volumes declined considerably, but this decline was offset by the wells we drilled to downsize the injection patterns.

In 2001 we spent $10.6 million on capital projects in the Arroyo Grande field, the most significant of which was drilling 19 production and 11 injection wells and installing a gas processing facility to reduce third-party fuel gas purchases. During 2002 we reduced capital expenditures to $1.5 million to allow time to assess the results of the 2001 drilling program and prepare to expand our steam flood in 2003-2004. We are also reviewing a plan to optimize steam handling and produced water disposal. In 2003 we expect to drill 15 to 20 wells and install a small cogeneration facility to reduce electricity costs and provide additional steam. Our net average daily production from this field was 1.9 MBOE per day during 2002.

Mt. Poso. In 1998 we acquired the Mt. Poso field from Aera Energy LLC. The Mt. Poso field is located near Bakersfield, California, in Kern County. Since acquisition, we have undertaken an aggressive recompletion and drilling program targeting the Pyramid Hills formation, completing a 107-well drilling program in 2000-2001. During 2002 we reduced capital expenditures to focus on optimizing operating costs, including the installation of electrical generation facilities, and reviewing past drilling results to identify future drilling potential. In 2002 we spent $0.8 million on capital projects to optimize our producing infrastructure. In 2003 we expect to drill 75 to 100 new wells. Our net average daily production from this field was 1.5 MBOE during 2002.

Offshore California

Point Arguello. In July 1999 we acquired ChevronTexaco's 26.3% working interest in the Point Arguello unit and the various partnerships owning the related transportation, processing and marketing infrastructure. We are the operator for the Point Arguello unit which consists of three offshore platforms. ChevronTexaco retained responsibility for certain abandonment costs, including: (1) removing, dismantling and disposing of the existing offshore platforms; (2) removing and disposing of all existing pipelines; and (3) removing, dismantling, disposing and remediating all existing onshore facilities. We assumed ChevronTexaco's 26.3% share of all other abandonment costs.

Effective August 1, 2002 we acquired an additional 26.3% working interest from subsidiaries of Phillips Petroleum Company in the Point Arguello unit and the various partnerships owning the related transportation, processing and marketing infrastructure with effect from April 1, 2002. The seller retained responsibility for certain abandonment costs, including: (1) removing, dismantling and disposing of the existing offshore platforms; (2) removing and disposing of all pipelines; and (3) removing, dismantling, disposing and remediating all existing onshore facilities. We assumed the seller's share of all other abandonment costs. As consideration for receiving the transferred properties and assuming the obligations described above we received $2.4 million. In addition, we received $2.7 million as our share of revenues less costs for the period prior to ownership from April 1 to July 31, 2002. This transaction doubled our working interest in the Point Arguello unit to 52.6%.

In 2002 we spent $6.2 million on capital projects, which included drilling 4 development wells, one of which was a dry hole, converting wells to electric submersible lift systems, and various workovers and stimulations. In 2003 we expect to drill one to two new wells and continue with our successful workover and high volume lift programs. At the time we acquired our interest in Point Arguello, our net average daily production from this unit was 5.2 MBOE. During 2002, including the effect of the interest acquired effective August 1, 2002, our net average daily production was 4.9 MBOE.

Rocky Point. Part of one of our leases in the Point Arguello unit is partially unitized in the Rocky Point unit, which is adjacent to the Point Arguello unit. As a result, we are the operator and have an agreement that entitles us to participate with at least a 52.6% working interest in the development of the Rocky Point unit. We are particularly interested in this unit because five exploratory wells were drilled into it in 1983-1984, and these wells tested at 3,500, 1,629, 1,100, 604 and 120 Bbls per day. Accordingly, we are currently seeking regulatory approval to allow near-term development of our lease in the Rocky Point unit by drilling extended-reach wells from the Point Arguello platforms. While we must obtain a larger rig and several regulatory permits and other agreements among the working interest owners, we believe that if we resolve these issues, we may be able to drill in the Rocky Point unit. There can be no assurance, however, that any such drilling can or will occur or that we will recover economic quantities of oil and gas from the Rocky Point unit. The other two leases that compose the Rocky Point unit are subject to litigation between the federal government and the state of California concerning the state's ability to review MMS approvals of lease suspensions for consistency with the state's Coastal Management Program and cannot be developed until the resolution of such litigation.

Illinois Basin

In December 1995 we acquired our properties in the Illinois Basin from Marathon Oil Company, which produced an average of 2.5 MBbls of oil per day in 2002 and accounted for 10% of our total sales volumes. In 2002, we spent $7.0 million on capital projects, which included drilling 38 development wells. In 2003 we expect to drill 35 to 45 wells and form new waterflood units to increase operations and recovery efficiency. In addition, we are continuing to evaluate the feasibility and potential implementation of a pilot program to field test an alkaline-surfactant enhanced oil recovery process.

Other

Our 2002 capital expenditures include $8.4 million of capitalized interest and general and administrative costs allocable directly to acquisition, exploitation and development activities and $2.6 million attributable to other projects.

Exploitation, Development, Exploration and Acquisition Expenditures

The following table summarizes the costs incurred during the last three years for our exploitation and development, exploration and acquisition activities (in thousands):

	Year Ended December 31,		
	2002	2001	2000
Property acquisitions costs:			
Unproved properties	$ 65	$ 44	$ 73
Proved properties(1)	(4,516)	1,645	1,953
Exploration costs	602	286	293
Exploitation and development costs(2)	68,346	123,778	68,186
	$64,497	$125,753	$70,505

(1) In connection with the acquisition of an additional interest in the Point Arguello field, offshore California, we assumed certain obligations of the seller. As consideration for receiving the transferred properties and assuming such obligations, we received $2.4 million. In addition, we received $2.7 million as our share of revenues less costs for the period April 1 to July 31, 2002 (the period prior to ownership).

(2) Exploitation and development costs include expenditures of $27.3 million in 2002, $58.5 million in 2001 and $20.6 million in 2000 related to the development of proved undeveloped reserves included in our proved oil and gas reserves at the beginning of each year.

Production and Sales

The following table presents information with respect to oil and gas production attributable to our properties, the revenues we derived from the sale of this production, average sales prices we received and our average production expenses during the years ended December 31, 2002, 2001 and 2000.

	Year Ended December 31,		
	2002	2001	2000
Sales			
Oil (MBbls)	8,783	8,219	7,654
Gas (MMcf)	3,362	3,355	3,042
MBOE	9,343	8,778	8,161
Revenue			
Oil	$178,038	$174,895	$126,434
Gas	10,299	28,771	16,017
Other	226	473	—
	$188,563	$204,139	$142,451
Average Prices and Costs			
Average Oil Sales Price ($/Bbl)			
Average NYMEX	$ 26.15	$ 26.01	$ 30.25
Hedging revenue (expense)	(1.77)	0.03	(9.51)
Differential	(4.11)	(4.76)	(4.22)
Net realized	$ 20.27	$ 21.28	$ 16.52
Average Gas Sales Price ($/Mcf)	$ 3.06	$ 8.58	$ 5.26
Average Sales Price per BOE	$ 20.16	$ 23.20	$ 17.46
Average Production Costs per BOE	(8.40)	(7.27)	(6.89)
Gross Margin per BOE	11.76	15.93	10.57
G&A per BOE(1)	(1.63)	(1.16)	(0.77)
Gross Profit per BOE	$ 10.13	$ 14.77	$ 9.80
DD&A per BOE (oil and gas properties)	$ 3.17	$ 2.70	$ 2.25

(1) Includes $4.4 million related to stock appreciation rights and spin-off costs in 2002.

Plains All American Pipeline, L.P., or PAA, is the exclusive purchaser of all of our equity oil production. See—Product Markets and Major Customers.

Product Markets and Major Customers

Our revenues are highly dependent upon the prices of, and demand for, oil and gas. 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 gas production and the levels of our production are subject to wide fluctuations and depend on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of OPEC, and domestic government regulation, legislation and policies. Decreases in oil and gas prices 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.

To manage our exposure to commodity price risks, we use 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 revenues on the hedged volumes than we would receive in the absence of hedges. We do not currently have any gas hedges. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk".

Deregulation of gas prices has increased competition and volatility of gas prices. Prices received for our gas are subject to seasonal variations and other fluctuations. All of our gas production is currently sold under various arrangements at spot indexed prices.

Substantially all of our oil and gas 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 decreases in a significant portion of our oil and gas production.

PAA is currently the exclusive purchaser of all of our equity oil production. We pay PAA a marketing and administration fee of $0.20 per barrel and reimburse PAA for its reasonable expenses incurred in transporting or exchanging our oil. We have agreed to renegotiate the marketing and administration fee in good faith every three years. Under the marketing agreement, PAA has also agreed to, upon our request and reimbursement for its reasonable expenses, market certain of our gas and gas liquids and negotiate our gas purchase agreements. If we were to lose PAA as the exclusive purchaser of our equity production, we believe PAA could be replaced by other purchasers under contracts with similar terms and conditions. However, PAA's role as the exclusive purchaser for all of our equity oil production does have 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 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 reasonably best efforts to obtain the best price for our oil production.

Productive Wells and Acreage

As of December 31, 2002 we had working interests in 2,148 gross (2,132 net) active producing oil wells. The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2002.

	December 31, 2002			
	Developed Acres		Undeveloped Acres(1)	
	Gross	Net	Gross	Net
Onshore California	8,889	8,844	9,272	6,289
Offshore California(2)	15,326	8,066	41,720	2,898
Illinois	16,622	14,628	13,625	5,418
Indiana	1,155	854	1,280	575
Kansas	—	—	48,147	37,647
Kentucky	—	—	1,321	521
Total	41,992	32,392	115,365	53,348

(1) Less than 10% of total net undeveloped acres are covered by leases that expire from 2003 through 2005.

(2) Excludes 3,264 undeveloped acres (net) that we have the right to acquire under an option agreement.

Drilling Activities

Information with regard to our drilling activities during the years ended December 31, 2002, 2001 and 2000 is set forth below:

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Oil	79.0	77.4	168.0	163.4	156.0	154.0
Dry	1.0	0.5	1.0	1.0	2.0	2.0
Total	80.0	77.9	169.0	164.4	158.0	156.0

Real Estate

We currently own surface and mineral rights in the following tracts of real property, portions of which are used in our oil and gas operations:

Property	Location	Approximate Acreage (Net to Our Interest)
Inglewood	Los Angeles County, California	25
Montebello	Los Angeles County, California	480
Arroyo Grande	San Luis Obispo County, California	1,047
Mt. Poso	Kern County, California	1,236
Gaviota	Santa Barbara County, California	84

In the course of our business, certain of our properties may be subject to easements or other incidental property rights and legal requirements that may affect the use and enjoyment of our property. For instance, 183 of our acres in the Montebello field have been designated as California Coastal Sage Scrub.

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 interfere with our use of the 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, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Competition

Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our larger competitors possess and employ financial and personnel resources substantially greater than ours. These competitors 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.

Regulation

Our 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 these rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas 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 United States Environmental Protection Agency 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.

MMS. The MMS has broad authority to regulate our oil and gas operations on offshore leases in federal waters. It must approve and grant permits in connection with our drilling and development plans. Additionally, the MMS has promulgated regulations requiring offshore production facilities to meet stringent engineering and construction specifications restricting the flaring or venting of gas, governing the plugging and abandonment of wells and controlling the removal of production facilities. Under certain circumstances, the MMS may suspend or terminate any of our operations on federal leases, as discussed in "Risk Factors—Governmental agencies and other bodies, including those in California, might impose regulations that increase our costs and may terminate or suspend our operations," and has proposed regulations that would permit it to expel unsafe operators from offshore operations. The MMS has also established rules governing the calculation of royalties and the valuation of oil produced from federal offshore leases and regulations regarding costs for gas transportation. Delays in the approval of plans and issuance of permits by the MMS because of staffing, economic, environmental or other reasons could adversely affect our operations.

Regulation of production. Oil and gas production is regulated 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 states in which we own and operate properties have 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. Many states also restrict production to the market demand for oil and gas, and several states have indicated interest in revising applicable regulations. These regulations limit the amount of oil and gas we can produce from our wells and limit the number of wells or the locations at which we can drill. Also, each state generally imposes an ad valorem, production or severance tax with respect to production and sale of oil, gas and natural gas liquids within its jurisdiction.

Pipeline regulation. We have pipelines to deliver our production to sales points. Our pipelines are subject to regulation by the United States Department of Transportation with respect to the design, installation, testing, construction, operation, replacement, and management of pipeline facilities. 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. The states in which we have pipelines have comparable regulations. Some of our pipelines related to the Point Arguello unit are also subject to regulation by the Federal Energy Regulatory Commission, or FERC. We believe that our pipeline operations are in substantial compliance with applicable requirements.

Sale of gas. The FERC regulates interstate gas pipeline transportation rates and service conditions. Although the FERC does not regulate gas producers such as us, the agency's actions are intended to foster increased competition within all phases of the gas industry. To date, the FERC's pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the gas industry will have on our gas sales efforts.

The FERC, the United States Congress or state regulatory agencies may consider additional proposals or proceedings that might affect the gas industry. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any of these proposals will affect us any differently than other gas producers with which we compete.

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 the 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 our 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 these 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.

Permits. Our operations are subject to various federal, state and local regulations that include requiring permits for the drilling of wells, maintaining bonding and insurance requirements to drill, operate, plug and abandon, and restore the surface associated with our wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandonment of wells, the disposal of fluids and solids used in connection with our operations and air emissions associated with our operations. Also, we have permits from the city and county of Los Angeles, California, the city of Culver City, California, the county of Kern, California, and the county of Santa Barbara, California to operate crude oil, natural gas and related pipelines and equipment that run within the boundaries of these governmental entities.

Plugging, Abandonment and Remediation Obligations

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. Typically when producing oil and gas assets are purchased, one assumes the obligation to plug and abandon wells that are part of such assets. However, in some instances, we receive an indemnity with respect to those costs.

Although we obtained environmental studies on our properties in California and Illinois and we believe that such properties have been operated in accordance with standard oil field practices, certain of the fields have been in operation for over 90 years, and current or future local, state and federal environmental laws and regulations may require substantial expenditures to comply with such rules and regulations. In connection with the purchase of certain of our onshore California properties, we received a limited indemnity for certain conditions if they violate applicable local, state and federal environmental laws and regulations in effect on the date of such agreement. We believe that we do not have any material obligations for operations conducted prior to our acquisition of the properties, other than our obligation to plug existing wells and those normally associated with customary oil field operations of similarly situated properties. Current or future local, state or federal rules and regulations may require us to spend material amounts to comply with such rules and regulations or that any portion of such amounts will be recoverable under the indemnity.

We estimate our 2003 cash expenditures related to plugging, abandonment and remediation will be approximately $2.3 million (including the costs required to be expended in connection with the purchase of certain of our onshore California properties). Due to the long life of our onshore reserve base we do not expect our cash outlays for such expenditures for these properties will increase significantly in the next several years. Although our offshore California properties have a shorter reserve life, third parties have retained the majority of the obligations for abandoning these properties.

In connection with the purchase of certain of our onshore California properties, each year we are required to plug and abandon 20% of the then remaining inactive wells (there were 154 inactive wells at December 31, 2002). If we do not meet this commitment, and the requirement is not waived, we must escrow funds to cover the cost of the wells that were not abandoned. To date we have not been required to escrow any funds. In addition, until the end of 2005, we are required to spend at least $600,000 per year (and $300,000 per year from 2006 through 2010) to remediate oil contaminated soil from existing well sites that require remediation.

Spin-off Agreements

In connection with our separation from Plains Resources, we entered into the following agreements:

Master Separation Agreement

Overview. To effect our separation from Plains Resources, we entered into a master separation agreement on July 3, 2002 with Plains Resources simultaneous with entering into our financing. The master separation agreement provides for the separation of substantially all of the upstream assets and liabilities of Plains Resources, other than its 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 Plains Resources;
- other provisions governing our relationship with Plains Resources, including mandatory dispute arbitration, sharing information, confidentiality and other covenants;
- a noncompetition provision; and
- us entering into the ancillary agreements discussed below with Plains Resources.

Separation. To effect the separation, on July 3, 2002, Plains Resources transferred to us assets and liabilities related to Plains Resources' upstream business other than its 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. We assumed the liabilities associated with the transferred assets and businesses. Plains Resources also transferred to us additional assets and liabilities, including remaining upstream agreements and permits that require consent to transfer and office furniture and equipment, and we will sublease a portion of Plains Resources' 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.

Plains Resources agreed to take such further actions as we may reasonably request to more effectively complete the transfers of assets and liabilities described above, to protect and enjoy all rights and benefits Plains Resources 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 us for all liabilities associated with the current and historical businesses and operations we conduct after giving effect to the separation, regardless of the time those liabilities arise, and to place sole financial responsibility for liabilities associated with Plains Resources' other businesses with Plains Resources and its other subsidiaries. The master separation agreement also contains indemnification provisions under which we and Plains Resources 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 Plains Resources and its other subsidiaries against liabilities arising from misstatements or omissions in the various offering documents for the exchange offer related to our 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 Plains Resources provided by Plains Resources for inclusion in such documents. Plains Resources agrees to indemnify us against liabilities arising from misstatements or omissions in the various offering documents for the exchange offer related to our 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 Plains Resources.

The master separation agreement contains a general release under which we released Plains Resources and its subsidiaries, affiliates, successors and assigns, and Plains Resources released us from any liabilities arising from events between us on the one hand, and Plains Resources or its subsidiaries on the other hand, occurring on or before the separation, including events in connection with activities to implement the separation, this offering 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 us, to future transactions between us and Plains Resources, or to specified contractual arrangements.

Other provisions. The master separation agreement also provides for: (1) mandatory arbitration to settle disputes between us and Plains Resources and its subsidiaries; (2) exchange of information between Plains Resources 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 Plains Resources 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 us 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) Plains Resources and its 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) we 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 our upstream activities.)

Employee Matters Agreement

We entered into an employee matters agreement with Plains Resources. The employee matters agreement does not address the treatment of Messrs. Flores, Raymond and Stephens, whom we call the executives, except with respect to the treatment of their existing options to acquire Plains Resources common stock.

Other employees. The employee matters agreement provided that those employees who work for us after the spin-off were transferred to us 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 Plains Resources common stock at the time of the spin-off were "split" into (1) an equal number of options to acquire Plains Resources common stock and (2) an equal number of stock appreciation rights, or SARs, with respect to our common stock.

The exercise price for the original Plains Resources stock options was also "split" between the new Plains Resources stock options and the SARs based on the following relative amounts: the closing price (with dividend) of Plains Resources common stock on the spin-off date less the closing price (on a "when-issued" basis) of our common stock on the spin-off date, both as reported on the NYSE, and such closing price of our common stock.

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 Plains Resources common stock were "split" into (1) restricted stock awards for an equal number of shares of Plains Resources common stock and (2) restricted stock awards for an equal number of shares of our common stock.

All recipients of our SARs and restricted stock awards received the benefit of prior service credit at Plains Resources and have the same amount of vesting as they had under their related Plains Resources stock options and restricted stock awards, and vesting terms remain unchanged. Also, an employee's or a director's service with us counts towards the vesting of their "split" Plains Resources stock options and restricted stock awards even though the employee is no longer employed by Plains Resources or the director no longer serves at Plains Resources. Likewise, with respect to employees and directors who stay with Plains Resources, their service at Plains Resources counts towards the vesting of their SARs even though they are not employed by us or do not serve on our board of directors.

Unless a person is employed by or serves as a director for both Plains Resources 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 Plains Resources 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) we established a nonqualified deferred compensation plan for certain executive officers and, to the extent that any of the executives are participants in the Plains Resources deferred compensation plan, the related assets and liabilities under the Plains Resources plan were transferred to our plan, (2) Plains Resources transferred its 401(k) plan and welfare benefit plans to us and formed a similar 401(k) plan and similar welfare benefit plans, and (3) we established plans that mirror the fringe benefits and company policies of Plains Resources.

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

Tax Allocation Agreement

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

In general, the agreement provides that we are included in Plains Resources' 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 Plains Resources during the period in which we are included in Plains Resources' consolidated group, we could be liable if any federal tax liability is incurred, but not discharged, by any other member of Plains Resources' consolidated group. In addition, to the extent Plains Resources' net operating losses are used in the consolidated return to offset our taxable income from operations during the period January 1, 2002 through the spin-off, we will reimburse Plains Resources 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 million exclusive of any interest accruing under the agreement. Such liability is reflected in our consolidated financial statements at December 31, 2002.

Under the terms of this agreement, we agree to indemnify Plains Resources if the spin-off is not tax-free to Plains Resources as a result of various actions taken by us or with respect to our failure to take various actions.

In addition, we agree that, during the three-year period following the spin-off, without the prior written consent of Plains Resources, we will not engage in transactions that could adversely affect the tax treatment of the spin-off unless we obtain a supplemental tax ruling from the IRS or a tax opinion acceptable to Plains Resources 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 Plains Resources to ensure we would be able to comply with our obligation under this agreement. We may not be able to control some of these events that could trigger this indemnification obligation.

We also agree 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 Plains Resources will transfer to us 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, we will grant to Plains Resources 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 our written consent, except that Plains Resources may grant its subsidiaries sublicenses to use the Plains Marks.

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

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

Plains Exploration & Production Transition Services Agreement

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

- management services, including managing our operations, evaluating investment opportunities for us, overseeing our 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 our 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 Plains Resources provides for us;
- 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.

Through December 31, 2002 Plains Resources has charged us $10.8 million of the maximum $30.0 million allowed under the agreement to reimburse it for its costs of providing such services. Plains Resources will continue to provide services under this agreement until June 16, 2002 unless we and Plains Resources decide to terminate the agreement earlier. We do not expect to incur significant additional charges under this agreement.

This transition services agreement provides that Plains Resources 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. Plains Resources will indemnify us for any liabilities arising from such gross negligence or misconduct. We will indemnify Plains Resources for any liabilities arising directly from the performance of the services by Plains Resources, except for liabilities caused by gross negligence or willful misconduct of Plains Resources. Plains Resources will disclaim all warranties and makes 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 we will provide Plains Resources the following services on an interim basis beginning on a date to be determined by both us and Plains Resources upon the transfer by Plains Resources of substantially all of its employees to us:

- tax services, including preparing tax returns and preparing financial statement disclosures;
- accounting services, including maintaining general ledgers, preparing financial statements and working with Plains Resources 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 Plains Resources' employees;
- legal services, including typical and customary legal services; and
- financial services, including helping Plains Resources raise capital, preparing budgets and executing hedges.

The services provided by us under the Plains Resources transition services agreement and the services provided by Plains Resources 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 have been historically provided for it and its subsidiaries by Plains Resources.

We will charge Plains Resources on a monthly basis our costs of providing such services.

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

We will be obligated to provide the services with substantially the same degree of care as we employ for our own operations. We may change the manner in which we provide the services so long as we deem such change to be necessary or desirable for our own operations.

This transition services agreement provides that we will not be liable to Plains Resources 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 Plains Resources for any liabilities arising from such gross negligence or misconduct. Plains Resources will indemnify us for any liabilities arising directly from our performance of the services, except for liabilities caused by our gross negligence or willful misconduct. We will disclaim all warranties and make 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 Plains Resources decide to terminate the agreement earlier. We and Plains Resources 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 Plains Resources, we 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.

Plains Resources will reimburse us for our costs to provide these services.

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

We and Plains Resources may agree to specific performance metrics that we must meet. Where no metrics are provided, we 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 we exercise in performing similar services for our subsidiaries, and (3) in cases where there is common personnel, equipment or facilities for services provided to our subsidiaries and Plains Resources, not favor Plains Resources or our subsidiaries over the other. We may change the manner in which we provide the services so long as we are making similar changes to the services we are providing to our subsidiaries.

We are not obligated to provide any service to the extent it is impracticable as a result of causes outside of our control.

The technical services agreement provides that we will not be liable to Plains Resources or Calumet 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 Plains Resources and Calumet for any liabilities arising from such gross negligence or misconduct. Plains Resources will indemnify us for any liabilities arising directly from the performance of the services, 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.

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

Employees

As of February 28, 2003 we had 354 full-time employees, 252 of whom were field personnel involved in oil and gas producing activities. We believe our relationship with our employees is good. None of our employees is represented by a labor union.

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 and financial condition, as well as adversely affect the value of an investment in our common stock.

Risks Relating to Our 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. In July 2002 we issued $200 million of 8.75% notes which are supported by guarantees of our subsidiaries. In addition, we have a $300.0 million revolving credit facility, which is collateralized by a pledge of the equity of our subsidiaries and substantially all of our other assets and supported by guarantees of our subsidiaries. At February 28, 2003 we had $33.5 million outstanding under this credit facility.

We have been assigned a Ba3 senior implied rating and our 8.75% notes have been assigned a B2 rating by Moody's Investor Service Inc. We have also been assigned a BB- corporate credit rating by Standard and Poor's Ratings Group. All of these ratings are below investment grade. As a result, at times we may have difficulty accessing capital markets or raising capital on favorable terms as we will incur higher borrowing costs than our competitors that have higher ratings. Therefore, our financial results may be negatively affected by our inability to raise capital or the cost of such capital as a result of our credit ratings.

We and all of our restricted subsidiaries must comply with various covenants contained in our revolving credit facility, the indenture related to our senior subordinated notes and any of our future debt arrangements which, among other things, limit the ability of us and those subsidiaries to:

- incur additional debt or liens;
- make payments in respect of or redeem or acquire any debt or equity issued by us;

- sell assets;
- make loans or investments;
- acquire or be acquired by other companies; and
- amend some of our contracts.

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 from operations 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 any of our debt, our lenders will have the right to accelerate the maturity of that debt and foreclose upon the collateral, if any, 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 and gas prices, which are extremely volatile. Any substantial or extended decline in the price of oil and gas below current levels will have a material adverse effect on our business operations and future revenues. Moreover, oil and gas prices depend on factors we cannot control, such as:

- supply and demand for oil and gas and expectations regarding supply and demand;
- weather;
- actions by the Organization of Petroleum Exporting Countries, or OPEC;
- political conditions in other oil-producing and gas-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 and gas 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 and gas, or distribution problems in meeting this demand, could adversely affect our business.

Our success is materially dependent upon the demand for oil and gas. The availability of a ready market for our oil and gas 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 and gas 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 and gas 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 and gas 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.

Our oil production in California is dedicated to a single customer and, as a result, our credit exposure to that customer is significant.

We have entered into an oil marketing agreement with Plains All American Pipeline, L.P., or PAA, under which PAA is the exclusive purchaser of all of our net oil production in California. We generally do not require letters of credit or other collateral from 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.

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

Our future success depends 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, particularly offshore, 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 and gas 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 and gas 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.

Substantially all of our oil and gas reserves are located in California and Illinois. 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.

Our California oil reserves average 23 degrees API gravity, which is heavier than premium grade light oil. Due to the processes required to refine this type of oil and the transportation requirements, it is difficult to market our oil outside California.

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.

In addition, our operations in California are especially susceptible to damage from natural disasters such as earthquakes and fires and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of southern California. 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. For example, we are not fully insured against earthquake risk in California because of high premium costs. Insurance covering earthquakes or other risks may not be available at premium levels that justify its purchase in the future, if at all. 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 incurs 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 California, 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 California, 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.

Under certain circumstances, the United States Minerals Management Service, or MMS, may require that our operations on federal leases be suspended or terminated. These circumstances include our failure to pay royalties or our failure to comply with safety and environmental regulations. The requirements imposed by these laws and regulations are frequently changed and subject to new interpretations.

Our offshore operations are subject to substantial regulations and risks, which could adversely affect our ability to operate and our financial results.

We conducts operations offshore California. Our offshore activities are subject to more extensive governmental regulation than our other oil and gas activities. In addition, we are vulnerable to the risks associated with operating offshore, including risks relating to:

- weather;
- oil field service costs and availability;
- compliance with environmental and other laws and regulations;
- remediation and other costs resulting from oil spills or releases of hazardous materials; and
- failure of equipment or facilities.

If we experience any of these events, we may incur substantial liabilities, which could adversely affect our operations and financial results.

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.

Some fields in our onshore California and Illinois Basin properties have been in operation for more than 90 years, and current or future local, state and federal environmental and other laws and regulations may require substantial expenditures to remediate the properties or to otherwise comply with these laws and regulations. In addition, approximately 183 acres of our 480 acres in the Montebello field have been designated as California Coastal Sage Scrub, a known habitat for the gnatcatcher, which is a species of bird designated as a federal threatened species under the Endangered Species Act. A variety of existing laws, rules and guidelines govern activities that can be conducted on properties that contain coastal sage scrub and gnatcatchers and generally limit the scope of operations that we can conduct on this property. The presence of coastal sage scrub and gnatcatchers in the Montebello field and other existing or future laws, rules and guidelines could prohibit or limit our operations and our planned activities for this property.

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 oil and gas 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.

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 and gas prices by actively hedging a portion of our production. Hedging also prevents us from receiving the full advantage of increases in oil or gas 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 do not have key man insurance. For information on our executive officers, our key employees, see Item 4. Submission of Matters to a Vote of Security Holders.

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

Because certain of our officers and directors provide services to Plains Resources, conflicts of interest could arise between Plains Resources, on the one hand, and us or you, on the other. Additionally, some of these officers and directors own and are awarded from time to time shares, or options to purchase shares, of Plains Resources. Accordingly, their financial interests may not always be aligned with ours or yours 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 Plains Resources.

Risks Relating to the Reorganization and Spin-off

Our historical financial results as a subsidiary of Plains Resources may not be representative of our results as a separate company.

The historical financial information included in this document does not necessarily reflect what our financial position, results of operations and cash flows would have been had we been a separate, stand-alone entity during the periods presented. Our costs and expenses reflect charges from Plains Resources for centralized corporate services and infrastructure costs. These allocations have been determined based on what we and Plains Resources considered to be reasonable reflections of the utilization of services provided to us or for the benefits we received. This historical financial information is not necessarily indicative of what our results of operations, financial position and cash flows will be in the future. We may experience significant changes in our cost structure, funding and operations as a result of our reorganization and spin-off from Plains Resources, including increased costs associated with reduced economies of scale, and increased costs associated with being a publicly traded, stand-alone company.

Under our tax allocation agreement with our former parent Plains Resources, if we take actions that cause the distribution of our stock by Plains Resources to its stockholders to fail to qualify as a tax-free transaction, we will be required to indemnify Plains Resources for the resulting tax liability and may not have sufficient financial resources to achieve our growth strategy or ability to repay debt or may prevent a change in control of us.

We have agreed with Plains Resources that we will not take any action inconsistent with any information, covenant or representation provided to the Internal Revenue Service in connection with obtaining the tax ruling stating that the spin-off will generally be tax-free to Plains Resources and its stockholders and we further agreed to be liable for any taxes arising from a breach of that agreement. In addition, we have agreed that, for three years following the spin-off, we will not engage in any transaction that could adversely affect the tax treatment of the spin-off without the prior written consent of Plains Resources, unless we obtains a supplemental tax ruling from the Internal Revenue Service or a tax opinion acceptable to Plains Resources of nationally recognized tax counsel to the effect that the proposed transaction would not adversely affect the tax treatment of the spin-off. Moreover, we will be liable to Plains Resources for any corporate level taxes incurred by Plains Resources as a result of the spin-off or to specified transactions involving us following the spin-off including the acquisition of 50% of our common stock by any person or persons. To the extent the taxes arise as a result of a change of control of Plains Resources, failure of Plains Resources to continue the active conduct of its trade or business or failure of Plains Resources to comply with the representations underlying its tax ruling or a supplemental tax ruling relating to the spin-off, Plains Resources will be solely responsible for the taxes resulting from the spin-off. If there are any corporate level taxes incurred by Plains Resources as a result of the spin-off and not due to any of the factors discussed in the two preceding sentences, we would be responsible for 50% of any such liability. The amount of any indemnification payments would be substantial and would likely result in events of default under all of our credit arrangements. 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 and agreements with Plains Resources 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.

Our net income could be adversely affected by stock appreciation rights charges.

As part of the spin-off, all outstanding options to acquire Plains Resources common stock at the time of the spin-off were "split" between Plains Resources stock options and Plains stock appreciation rights.

SARs are subject to variable accounting treatment. As a result, at the end of each quarter, we will compare the closing price of our common stock on the last day of the quarter to the exercise price of each outstanding or unexercised SAR that is vested or for accounting purposes is deemed vested at the end of the quarter. For example, if a SAR is scheduled to vest on December 31, for accounting purposes one-fourth of the shares are deemed to vest at the end of each quarter even though no vesting legally occurs until December 31. To the extent the closing price at the end of each quarter exceeds the exercise price of each SAR, we will recognize such excess as an accounting charge for the SARs deemed vested to the extent such excess has not previously been recognized as expense. If the quarter-end closing price decreases compared to prior periods, we will recognize credits to income, to the extent we have previously recognized expense. These quarterly charges and credits will make our results of operations depend, in part, on fluctuations in the price of our common stock and could have a material adverse effect on our results of operations. We will incur cash expenditures as SARs are exercised, but our common share count will not increase.

We recognized compensation expense of $2.7 million, representing the difference in our common stock price on December 18, 2002, the date of the spin-off, and the exercise price of each SAR deemed vested on that date. In addition, we recognized compensation expense of $1.0 million, representing the increase in our stock price and the vesting deemed to have occurred from the spin-off date to December 31, 2002. As of December 31, 2002, we had approximately 4.0 million SARs outstanding with an average exercise price of $8.68, of which 2.6 million of the SARs were deemed vested.

Item 3. *Legal Proceedings*

On September 18, 2002 Stocker Resources Inc., or Stocker, our general partner before we 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. In December 2002, Stocker was merged into Plains Resources. Under our master separation agreement with Plains Resources, we must indemnify Plains Resources for damages it incurs as a result of this action. We understand that Plains Resources intends to defend its 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 Exploration & Production Company

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, Chairman of the Board, Chief Executive Officer and a Director since September 2002. Mr. Flores was Chairman of the Board and Chief Executive Officer of Plains Resources from May 2001 until December 2002 and has been Executive Chairman of the Board of that company since 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.

Alan R. Buckwalter, III, age 56, Director since March 2003. Mr. Buckwalter retired in January 2003 as Chairman of JPMorgan Chase Bank, South Region, a position he had held since 1998. From 1990 to 1998 he was President of Texas Commerce Bank-Houston, the predecessor entity of JPMorgan Chase Bank. Prior to 1990 Mr. Buckwalter held various executive management positions within the organization. Mr. Buckwalter currently serves on the boards of the Texas Medical Center, the Federal Reserve Bank of Dallas, Houston Branch and he is currently serving as Chairman of the Board of Trustees for Texas Southern University Foundation.

Jerry L. Dees, age 63, Director since September, 2002. Mr. Dees retired in 1996 as Senior Vice President, Exploration and Land, for Vastar Resources, Inc. (previously ARCO Oil and Gas Company), a position he had held since 1991. From 1987 to 1991 he was Vice President of Exploration and Land for ARCO Alaska, Inc., and from 1985 to 1987 he held various positions as Exploration Manager of ARCO. From 1980 to 1985 Mr. Dees was Manager of Exploration Geophysics for Cox Oil and Gas Producers. Mr. Dees was a director of Plains Resources from 1997 until 2002.

Tom H. Delimitros, age 62, Director since September, 2002. Mr. Delimitros has been a General Partner of AMT Venture Funds, a venture capital firm, since 1989. He is also a director of Tetra Technologies, Inc., a publicly-traded energy services company. He currently serves as Chairman for two privately-owned companies—ImageLinks, Inc., and InterCorp International Inc.—both of which sell products and services to energy companies. Previously, he has served as President and CEO for Magna Corporation, (now Baker Petrolite, a unit of Baker Hughes). From 1983 to 1988, Mr. Delimitros was a General Partner of Sunwestern Investment Funds and Senior Vice President of Sunwestern Management, Inc. Mr. Delimitros was a director of Plains Resources from 1988 until 2002.

John H. Lollar, age 64, Director since September, 2002. Mr. Lollar has been the Managing Partner of Newgulf Exploration L.P. since December 1996. He is also a director of Lufkin Industries, Inc., a manufacturing firm. Mr. Lollar was Chairman of the Board, President and Chief Executive Officer of Cabot Oil & Gas Corporation from 1992 to 1995, and President and Chief Operating Officer of Transco Exploration Company from 1982 to 1992. Mr. Lollar was a director of Plains Resources from 1995 until 2002.

Executive Officers

John T. Raymond, age 32, President and Chief Operating Officer since September 2002. Since December 2002 Mr. Raymond has also served as Chief Executive Officer of Plains Resources. From November 2001 until December 2002 he was Plains Resources' President and Chief Operating Officer. Previously, he was its 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.

Stephen A. Thorington, age 47, Executive Vice President and Chief Financial Officer since September 2002. Mr. Thorington has also served as Executive Vice President and Chief Financial Officer of Plains Resources since February 2003 and from December 2002 until February 2003 he served as Acting Executive Vice President and Chief Financial Officer. 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. Mr. Thorington served as a Managing Director of Chase Securities, Inc. from April 1994 to May 1996.

Timothy T. Stephens, age 50, Executive Vice President—Administration, Secretary and General Counsel since September 2002. Mr. Stephens was Plains Resources' Executive Vice President—Administration, Secretary and General Counsel from May 2001 until September 2002. From March 2000 to May 2001 Mr. Stephens practiced as a private business consultant to various clients. In February 1998 Mr. Stephens was hired by the board of directors of Abacan Resources Corporation, an oil and gas company, to help the company overcome significant financial difficulties. He served as Chairman, President and Chief Executive Officer of Abacan until March 2000 when the company, after a two-year restructuring, was placed into statutory receivership with the agreement of its senior creditor. Previously, Mr. Stephens was President of Seven Seas Petroleum from February 1995 to May 1997, and Vice President of Enron Capital & Trade Resources Corp. from July 1991 to February 1995.

Cynthia A. Feeback, age 45, Senior Vice President—Accounting and Treasurer since September 2002. Ms. Feeback was Plains Resources' Senior Vice President—Accounting and Treasurer from July 2001 until September 2002. She was its Vice President—Accounting and Assistant Treasurer from May 1999 to July 2001, and its Assistant Treasurer, Controller and Principal Accounting Officer from May 1998 to May 1999. Previously, Ms. Feeback served as its Controller and Principal Accounting Officer from 1993 to 1998, Controller from 1990 to 1993, and Accounting Manager from 1988 to 1990.

Thomas M. Gladney, age 50, Senior Vice President of Operations since September 2002. Mr. Gladney was Plains Resources' Senior Vice President of Operations from November 2001 until September 2002. He was President of Arguello, Inc., a subsidiary of ours, from December 1999 to November 2001. From July 1999 to December 1999 he served as a Project Manager for Torch Energy Services, a contract operating services company. From January 1999 to June 1999 he served as a Project Manager for Venoco Inc., an oil and gas company. From September 1998 to January 1999 he was a self-employed engineering services consultant. From 1992 to September 1998 he was Offshore Operations Manager for Oryx Energy Company. Previously, he served as Gulf Coast Reserve Development Manager of Oryx Energy/Sun E&P from 1988 to 1992.

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

Price Range of Common stock

Our common stock is listed on the New York Stock Exchange under the symbol "PXP" and began trading on December 18, 2002. During 2002 the high and low closing sales prices of our common stock as reported on the applicable New York Stock Exchange Composite Tape were $10.00 and $9.75, respectively.

Dividend Policy

We do not anticipate declaring or paying any cash dividends in the future. We intend to retain our earnings to finance the expansion of our business and for general corporate purposes. Our board of directors will have the authority to declare and pay dividends on our common stock in its discretion, as long as we have funds legally available to do so. Our credit facility and the indenture relating to our 8.75% notes restrict our ability to pay cash dividends.

Recent Sales of Unregistered Securities

On September 28, 1990 we were formed as a California limited partnership. On September 18, 2002 we converted into a Delaware limited partnership, and then converted into a Delaware corporation. As a result of the conversion, on September 18, 2002 our limited partnership interests were converted into 975 shares of our common stock which were issued to Plains Resources Inc. and 25 shares of our common stock which were issued to Stocker Resources Inc., a wholly owned subsidiary of Plains Resources. No additional consideration was received for these shares. On September 30, 2002 we declared a stock dividend in an amount equal to 24,199 shares of our common stock for each share of our common stock outstanding, resulting in the issuance of 24,199,000 shares of our common stock to Plains Resources and Stocker. All such issuances were exempt from registration under Section 4(2) of the Securities Act of 1933, as amended, or the Securities Act, as issuances not involving any public offering of securities.

On July 3, 2002 we issued, at an issue price of 98.376%, $200.0 million of 8.75% senior subordinated notes due 2012. The 8.75% notes were issued to J.P. Morgan Securities Inc., Goldman, Sachs & Co., Banc One Capital Markets, Inc., BNP Paribas Securities Corp., Fleet Securities, Inc. and Fortis Investment Services LLC in an exempt transaction under Rule 144A and Regulation S of the Securities Act. These notes are our unsecured general obligations, are subordinated in right of payment to all of our existing and future domestic restricted subsidiaries. We filed a registration statement with the SEC and all holders of these notes have exchanged these notes for registered notes having substantially the same terms. We distributed the net proceeds of $195.3 million from the sale of these notes, together with $116.7 million in initial borrowings under our credit facility, to Plains Resources, which used the proceeds to redeem its 10.25% senior subordinated notes and repay $25.0 million outstanding under its credit facility.

We have not sold any other securities, registered or otherwise, within the past three years.

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. You should read this information in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and notes thereto. This information is not necessarily indicative of our future results (in thousands, except per share data):

	Year Ended December 31,				
	2002	2001	2000	1999	1998
Revenues					
Oil sales to Plains All American Pipeline, L.P.	$178,038	$174,895	$126,434	$102,390	$ 81,416
Gas sales	10,299	28,771	16,017	5,095	4,091
Other operating revenues	226	473	—	—	—
	188,563	204,139	142,451	107,485	85,507
Costs and Expenses					
Production expenses	78,451	63,795	56,228	50,527	42,823
General and administrative					
Stock appreciation rights	3,653	—	—	—	—
Spin-off costs	777	—	—	—	—
Other	10,756	10,210	6,308	4,367	3,218
Depreciation, depletion and amortization	30,359	24,105	18,859	13,329	13,901
Reduction in carrying cost of oil and gas properties(1)	—	—	—	—	42,920
	123,996	98,110	81,395	68,223	102,862
Income (Loss) from Operations	64,567	106,029	61,056	39,262	(17,355)
Other Income (Expense)					
Expenses of terminated public equity offering	(2,395)	—	—	—	—
Interest expense	(19,377)	(17,411)	(15,885)	(14,912)	(8,828)
Interest and other income	174	463	343	87	74
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	42,969	89,081	45,514	24,437	(26,109)
Income tax (expense) benefit					
Current	(6,353)	(6,014)	(2,431)	(505)	(4,435)
Deferred	(10,379)	(28,374)	(14,334)	(4,827)	11,510
Income Before Cumulative Effect of Accounting Changes	26,237	54,693	28,749	19,105	(19,034)
Cumulative effect of accounting change, net of tax benefit(2)	—	(1,522)	—	—	—
Net Income (Loss)	$ 26,237	$ 53,171	$ 28,749	$ 19,105	$(19,034)
Earnings Per Share, Basic and Diluted					
Income (loss) before cumulative effect of accounting change	$ 1.08	$ 2.26	$ 1.19	$ 0.79	$ (0.79)
Cumulative effect of accounting change	—	(0.06)	—	—	—
Net income (loss)	$ 1.08	$ 2.20	$ 1.19	$ 0.79	$ (0.79)
Weighted Average Common Shares Outstanding					
Basic	24,193	24,200	24,200	24,200	24,200
Diluted	24,201	24,200	24,200	24,200	24,200

Table and footnotes continued on following page

	Year Ended December 31,				
	2002	2001	2000	1999	1998
Cash Flow Data					
Net cash provided by (used in) operating activities	$ 78,826	$ 116,808	$ 79,464	$ 4,609	$ 37,182
Net cash provided by (used in) investing activities	(64,158)	(125,880)	(70,871)	(59,362)	(91,838)
Net cash provided by (used in) financing activities	(13,653)	8,549	(13,132)	59,690	54,587

	As of December 31,				
	2002	2001	2000	1999	1998
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 1,028	$ 13	$ 536	$ 5,075	$ 138
Other current assets	37,711	42,798	36,916	45,287	14,178
Property and equipment, net	493,212	455,117	353,344	301,332	255,299
Other assets	18,929	18,827	10,239	9,270	8,177
	$550,880	$ 516,755	$401,035	$360,964	$277,792
Liabilities and Stockholders' Equity					
Current liabilities	$ 86,175	$ 41,879	$ 44,313	$ 34,193	$ 26,464
Long-term debt and payable to Plains Resources	233,166	236,183	226,529	239,661	179,972
Other long-term liabilities	6,303	1,413	—	—	8,179
Deferred income taxes	51,416	57,193	19,161	4,827	—
Stockholders' equity/combined owner's equity	173,820	180,087	111,032	82,283	63,177
	$550,880	$ 516,755	$401,035	$360,964	$277,792

(1) Noncash charge related to a ceiling test write-down of the capitalized costs of our proved oil and gas properties due to low oil prices at December 31, 1998.

(2) Cumulative effect of adopting Statement of Financial Accounting Standards No. 133—"Accounting for Derivatives," or SFAS 133.

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.

Corporate Reorganization and Spin-off

Under the terms of a Master Separation Agreement between us and Plains Resources, on July 3, 2002 Plains Resources contributed to us (i) 100% of the capital stock of its wholly owned subsidiaries Arguello Inc., Plains Illinois Inc., PMCT Inc. and Plains Resources International Inc.; and (ii) all amounts payable to it by us and our subsidiary companies.

Prior to December 18, 2002 we were a wholly owned subsidiary of Plains Resources. On December 18, 2002 Plains Resources distributed 100% of the issued and outstanding shares of our common stock to the holders of record of Plains Resources' common stock as of December 11, 2002. Each Plains Resources stockholder received one share of our common stock for each share of Plains Resources common stock held. Prior to the spin-off, Plains Resources made an aggregate of $52.2 million in cash contributions to us and transferred to us certain assets and we assumed certain liabilities of Plains Resources, primarily related to land, unproved oil and gas properties, office equipment and pension obligations. We used the cash contributions to reduce outstanding debt under our revolving credit facility.

Plains Resources received a favorable private letter ruling from the Internal Revenue Service stating that, for United States federal income tax purposes, the distribution by Plains Resources 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 Plains Resources to obtain cost savings through improved access to capital markets for its midstream affiliate, Plains All American Pipeline, L.P.;
- allow Plains Resources and us to focus corporate strategies and management teams for each business; and
- simplify Plains Resources' and our corporate structure.

Recent Developments

On February 3, 2003 we announced that we entered into a definitive agreement pursuant to which we will acquire 3TEC for approximately $333.0 million plus the assumption of debt, which totaled $99.0 million at December 31, 2002. Under the terms of the merger agreement, 3TEC common stockholders will receive $8.50 of cash and 0.85 of a share of our common stock for each share of 3TEC common stock they own, which equates to a total of $16.97 per 3TEC common share based on the January 31, 2003 closing price of $9.96 per share for our common stock. This exchange ratio is subject to an upward or downward adjustment should the market price of our common stock fall below $7.65 per share or rise above $12.35 per share, respectively. This mechanism is intended to provide that the total value of the consideration received by 3TEC common stockholders at the effective time of the merger will be between $15.00 and $19.00 per share of 3TEC common stock. For this purpose, the market price of our common stock will be the average closing price of our common stock for the 20 consecutive trading days immediately preceding the third trading day prior to closing. In addition, if the market price of our common stock is less than $6.25, we may either (i) terminate the merger agreement or (ii) in lieu of issuing more common stock increase the cash consideration paid per share of 3TEC common stock by the amount our common stock market price is less than $6.25 times the exchange ratio after adjustment.

The merger is expected to qualify as a tax free reorganization under Section 368(a) of the Internal Revenue Code. Accordingly, the merger is expected to be tax free to our stockholders and tax free for the stock portion of the consideration received by 3TEC stockholders. We anticipate funding the cash portion of the merger through a new credit facility.

The Boards of Directors of both companies have approved the merger agreement and each has recommended it to their respective stockholders for approval. The transaction is subject to stockholder approval from both companies and other customary conditions. Assuming the market price of our common stock is between $7.65 and $12.35, after the merger is completed, 3TEC common stockholders will own approximately 40% of the combined company and our stockholders will own approximately 60% of the combined company.

General

We are an independent oil and gas company primarily engaged in the upstream activities of acquiring, exploiting, developing and producing oil and gas in the United States. Our core areas of operation are:

- onshore California, primarily in the LA Basin;
- offshore California in the Point Arguello unit; and
- the Illinois Basin in southern Illinois and Indiana.

We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration, exploitation and development activities are capitalized. Under the full cost method, we capitalize internal general and administrative costs that can be directly identified with our acquisition, exploration and development activities and do not capitalize any costs related to production, general corporate overhead or similar activities. Our revenues are derived from the sale of oil, gas and natural gas liquids. 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 and gas. 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 gas 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 and gas 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 and gas prices decline significantly 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 less revenues on the hedged volumes than we would receive in the absence of hedges. We do not currently have any gas hedges. Gains and losses from hedging transactions are recognized as revenues when the associated production is sold.

Our oil and gas 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. We estimate that as a result of our reorganization and spin-off, our annual general and administrative expenses will increase by approximately $4.1 million over the amount reported for the year ended December 31, 2002 (excluding expense related to stock appreciation rights and spin-off costs) reflecting the incremental costs of operating as a separate, publicly held company.

Tax expense and effective tax rates have been calculated based on the tax sharing agreement covering all the members of the consolidated group on a combined basis for such periods through the spin-off date.

Results of Operations

The following table reflects the components of our oil and gas production and sales prices and sets forth our operating revenues and costs and expenses on a BOE basis:

	Year Ended December 31,		
	2002	2001	2000
Sales Volumes			
Oil and liquids (MBbls)	8,783	8,219	7,654
Gas (MMcf)	3,362	3,355	3,042
MBOE	9,343	8,778	8,161
Daily Average Sales Volumes			
Oil (Bbls)			
Onshore California	16,671	15,858	13,990
Offshore California	4,851	3,920	4,122
Illinois	2,540	2,740	2,799
	24,062	22,518	20,911
Gas (Mcf)			
Onshore California	9,211	9,192	8,312
BOE	25,597	24,050	22,296
Unit Economics (in dollars)			
Average Oil Sales Price ($/Bbl)			
Average NYMEX	$ 26.15	$ 26.01	$ 30.25
Hedging revenue (expense)	(1.77)	0.03	(9.51)
Differential	(4.11)	(4.76)	(4.22)
Net realized	$ 20.27	$ 21.28	$ 16.52
Average Gas Sales Price ($/Mcf)	$ 3.06	$ 8.58	$ 5.26
Average Sales Price per BOE	$ 20.16	$ 23.20	$ 17.46
Average Production Expenses per BOE	(8.40)	(7.27)	(6.89)
Gross Margin per BOE	11.76	15.93	10.57
G&A per BOE (1)	(1.63)	(1.16)	(0.77)
Gross Profit per BOE	$ 10.13	$ 14.77	$ 9.80
DD&A per BOE (oil and gas properties)	$ 3.17	$ 2.70	$ 2.25

(1) Includes $4.4 million related to stock appreciation rights and spin-off costs in 2002.

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

Net income. We reported net income of $26.2 million, or $1.08 per diluted share for the year ended December 31, 2002 compared to net income of $53.2 million, or $2.20 per diluted share for 2001. A discussion of the reasons for the decrease follows.

Operating revenues. Our operating revenues decreased 8%, or $15.5 million, to $188.6 million for the year ended December 31, 2002 from $204.1 million for the year ended December 31, 2001. The decrease was primarily due to lower realized prices for oil and gas that reduced revenues by $26.8 million. Higher volumes increased revenues by $11.5 million.

Our daily oil sales volumes increased 7%, or 1.6 MBbls, to 24.1 MBbls per day for the year ended December 31, 2002 from 22.5 MBbls for the year ended December 31, 2001 primarily due to the effect of the acquisition of an additional 26.3% interest in our offshore California properties in 2002 which doubled our working interest in these properties. Our daily gas sales volumes were 9.2 MMcf per day for the year ended December 31, 2002, unchanged from the year ended December 31, 2001.

Our average realized price for oil and natural gas liquids decreased 5%, or $1.01 to $20.27 per Bbl for the year ended December 31, 2002 from $21.28 per Bbl for the year ended December 31, 2001 primarily due to the effect of our hedges in 2002. For the year ended December 31, 2002, our hedges decreased our average oil price by $1.77 per barrel compared to a $.03 per Bbl increase in 2001. The increased hedging cost was partially offset by a 14%, or $0.65 per Bbl improvement in location and quality differentials over the same periods. The average NYMEX oil price increased 1%, or $0.14, to $26.15 per Bbl for the year ended December 31, 2002 from $26.01 per Bbl for the year ended December 31, 2001. The average realized price for gas decreased 64%, or $5.52, to $3.06 per Mcf for the year ended December 31, 2002 from $8.58 per Mcf in 2001. Gas prices were unusually high in 2001, particularly in California.

Production expenses. Our production expenses increased 23%, or $14.7 million, to $78.5 million for the year ended December 31, 2002 from $63.8 million for the year ended December 31, 2001. On a per unit basis, production expenses increased 16%, or $1.13 per BOE, to $8.40 per BOE for the year ended December 31, 2002 from $7.27 per BOE for the year ended December 31, 2001. Production expenses for 2001 were reduced by approximately $0.25 per BOE as a result of nonrecurring credits (primarily the sale of certain California emissions credits). Excluding these credits, production expenses increased 12% per BOE in 2002, primarily due to increased workover and maintenance expense, insurance expense and electricity costs in California as well as our increased ownership percentage in the offshore California properties, which have a higher per unit production cost than our other properties. Unit production expenses for the offshore California properties will continue to increase as production declines due to the large component of fixed expenses for this asset.

General and administrative expense. Our general and administrative, or G&A, expense, excluding amounts attributable to stock appreciation rights and costs related to our spin-off from Plains Resources, increased 6%, or $0.6 million, to $10.8 million in 2002 from $10.2 million in 2001. This increase was primarily due to higher personnel cost. G&A expense for 2002 includes approximately $0.8 million of legal and other costs related to our spin-off and approximately $3.7 million of expense attributable to the in-the-money value of stock appreciation rights issued on the spin-off date. G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. We capitalized $6.3 million and $6.2 million of G&A expense in 2002 and 2001, respectively.

Depreciation, depletion and amortization. DD&A increased 26%, or $6.3 million, to $30.4 million for the year ended December 31, 2002 from $24.1 million for the year ended December 31, 2001. Approximately $4.1 million of the increase was attributable to a higher unit rate ($3.17 per BOE in 2002 versus $2.70 in 2001) and $1.8 million was attributable to increased production in 2002. DD&A is affected by many factors, including production levels, costs incurred in the acquisition, exploitation and development of proved reserves and estimates of proved reserve quantities and future development costs. The increase in our DD&A rate in 2002 was primarily due to our capital program resulting in higher costs being subject to DD&A and, to a lesser extent, to higher estimated future development costs.

Expenses of terminated public equity offering. In conjunction with the termination of our proposed initial public equity offering we expensed costs incurred of $2.4 million in 2002.

Interest expense. Our interest expense increased 11%, or $2.0 million, to $19.4 million for the year ended December 31, 2002 from $17.4 million for the year ended December 31, 2001, reflecting higher debt balances during 2002 and a decrease in the amount of capitalized interest, partially offset by lower interest rates. We capitalized approximately $2.4 million and $3.1 million of interest in 2002 and 2001, respectively.

Income tax expense. Our income tax expense decreased 51%, or $17.7 million to $16.7 million for the year ended December 31, 2002 from $34.4 million for the year ended December 31, 2001. The decrease was primarily due to decreases in pre-tax income. Our overall effective tax rate increased slightly to 38.9% in 2002 from 38.6% for the year ended December 31, 2001. Our currently payable effective tax rate was 14.8% for the year ended December 31, 2002 as compared to 6.8% for the year ended December 31, 2001. The increased currently payable effective rate in 2002 primarily reflects lower expenditures that are expensed for tax purposes and capitalized for financial reporting purposes and the $3.7 million in expense related to stock appreciation rights that is not deductible until paid. Tax expense and effective tax rates for the periods prior to our spin-off on December 18, 2002 were calculated based on the tax sharing agreement with Plains Resources.

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

Net income. We reported net income of $53.2 million, or $2.20 per diluted share, for the year ended December 31, 2001 compared to net income of $28.7 million, or $1.19 per diluted share for 2001. A discussion of the reasons for the increase follows.

Operating revenues. Our operating revenues increased 43%, or $61.6 million, to $204.1 million in 2001 from $142.5 million in 2000. The increase primarily reflects higher realized oil and gas prices. Increased prices contributed $46.7 million in additional revenues, and increased sales volumes contributed $14.9 million.

Our daily oil sales volumes increased 8%, or 1.6 MBbls, to 22.5 MBbls in 2001 from 20.9 MBbls in 2000. Our daily gas sales volumes increased 11%, or 0.9 MMcf, to 9.2 MMcf in 2001 from 8.3 MMcf in 2000. Production increases were primarily attributable to the continuing development of our onshore California properties.

Our average realized price for oil increased 29%, or $4.76, to $21.28 per Bbl in 2001 from $16.52 per Bbl in 2000. The average NYMEX oil price decreased 14%, or $4.24, to $26.01 per Bbl in 2001 from $30.25 per Bbl in 2000. The NYMEX decrease was more than offset by a $9.54 per Bbl increase in our hedging margin. The average realized price for gas increased 63%, or $3.32, to $8.58 per Mcf in 2001 from $5.26 per Mcf in 2000. Gas prices were unusually high in 2001, particularly in California.

Production expenses. Our production expenses increased 13%, or $7.6 million, to $63.8 million in 2001 from $56.2 million in 2000. Expenses for 2001 were reduced by $2.2 million primarily due to the sale of California emission credits. Excluding the credits, production expenses on a BOE basis increased 9%, or $0.63, to $7.52 per BOE in 2001 from $6.89 per BOE in 2000. The increase is primarily due to higher electricity costs in California.

General and administrative expense. Our G&A expense increased 62%, or $3.9 million, to $10.2 million in 2001 from $6.3 million in 2000. This increase was primarily due to a $3.7 million increase in G&A expenses allocated by Plains Resources. The increase in Plains Resources' G&A expenses was primarily due to costs related to its 2001 corporate reorganization. G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. We capitalized $6.2 million and $5.2 million of G&A expense in 2001 and 2000, respectively.

Depreciation, depletion and amortization. Our DD&A expense increased 28%, or $5.2 million, to $24.1 million in 2001 from $18.9 million in 2000, as our oil and gas DD&A rate increased 20%, or $0.45, to $2.70 per BOE in 2001 from $2.25 per BOE in 2000. DD&A is affected by many factors, including production levels, costs incurred in the acquisition, exploitation and development of proved reserves and estimates of proved reserve quantities and future development costs. The increase in our DD&A rate in 2001 was primarily due to our capital program resulting in higher costs being subject to DD&A and, to a lesser extent, to higher estimated future development costs.

Interest expense. Our interest expense increased 10%, or $1.5 million, to $17.4 million in 2001 from $15.9 million in 2000, reflecting higher amounts owed to Plains Resources which were partially offset by lower interest rates.

Income tax expense. Our income tax expense increased 105%, or $17.6 million, to $34.4 million in 2001 from $16.8 million in 2000. The increase was primarily due to a 96% increase in income before income taxes and cumulative effect of accounting change from $45.5 million in 2000 to $89.1 million in 2001. In addition, our effective tax rate increased to 38.6% in 2001 from 36.8% in 2000.

Cumulative effect. The cumulative effect of accounting change recognized for the year ended December 31, 2001 was for the adoption of Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operations and our revolving credit facility. At February 28, 2003 we had approximately $186.3 million of availability under our revolving credit facility. We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our revolving credit facility to meet our short-term and long-term normal recurring operating needs, debt service obligations, contingencies and anticipated capital expenditures.

Financing Activities

On July 3, 2002 we issued $200.0 million of 8.75% notes. The 8.75% notes are our unsecured general obligations, are subordinated in right of payment to all of our existing and future senior indebtedness and are jointly and severally guaranteed on a full, unconditional basis by all of our existing and future domestic restricted subsidiaries. On July 3, 2002 we also entered into a $300.0 million revolving credit facility with a borrowing base of $225.0 million.

We distributed the net proceeds of $195.3 million from the 8.75% notes and $116.7 million in initial borrowings under our credit facility to Plains Resources, which used it to repay debt. Our guarantees of Plains Resources debt facilities were terminated when it retired such obligations.

Plains and JP Morgan Chase Bank have entered into a commitment letter for a three-year, $500.0 million senior revolving credit facility. See "—Capital Requirements" for a summary of the credit facility terms.

At December 31, 2002 we had a working capital deficit of approximately $47.4 million. Approximately $22.0 million of the working capital deficit is attributable to the fair value of our hedges, approximately $8.7 million is attributable to accrued interest on the 8.75% notes and $3.4 million reflects the in-the-money value of stock appreciation rights that were deemed vested at December 31, 2002. Interest on the 8.75% notes is payable semi-annually on January 1 and July 1 of each year, commencing on January 1, 2003. In accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", the fair value of all derivative instruments is recorded on the balance sheet. Gains and losses on hedging instruments are included in oil and gas revenues in the period that the related volumes are delivered. The hedge agreements provide for monthly settlement based on the differential between the agreement price and actual NYMEX oil price. Cash received for the sale of physical production will be based on actual market prices and will generally offset any gains or losses on the hedge instruments. The remaining working capital deficit of approximately $13.3 million will be financed through cash flow and borrowings under our credit facility.

As of February 28, 2003 we had $33.5 million in borrowings and $5.2 million in letters of credit outstanding under our $300.0 million revolving credit facility. The credit facility provides for a borrowing base of $225.0 million that will be reviewed every six months, with the lenders and us each having the right to one annual interim unscheduled redetermination, and adjusted based on our oil and gas properties, reserves, other indebtedness and other relevant factors, and matures in 2005. The credit facility contains a $30.0 million sub-limit on letters of credit. To secure borrowings, we pledged 100% of the shares of stock of our domestic subsidiaries, who also unconditionally guarantee payments under the credit facility, and gave mortgages covering 80% of the total present value of our domestic oil and gas properties.

Amounts borrowed under the credit facility bear an annual interest rate, at our election, equal to either: (i) the Eurodollar rate, plus from 1.375% to 1.75%; or (ii) the greatest of (1) the prime rate, as determined by JPMorgan Chase Bank, (2) the certificate of deposit rate, plus 1.0%, or (3) the federal funds rate, plus 0.5%; plus an additional 0.125% to 0.5% for each of (1)-(3). The amount of interest payable on outstanding borrowings is based on (1) the utilization rate as a percentage of the total amount of funds borrowed under the credit facility to the borrowing base and (2) our long-term debt rating. Commitment fees and letter of credit fees under the credit facility are based on the utilization rate and long-term debt rating. Commitment fees range from 0.375% to 0.5% of the unused portion of the borrowing base. Letter of credit fees range from 1.375% to 1.75%. The issuer of any letter of credit receives an issuing fee of 0.125% of the undrawn amount.

The credit facility contains negative covenants that limit our ability, as well as the ability of our subsidiaries, among other things, to incur additional debt, pay dividends on stock, make distributions of cash or property, change the nature of our business or operations, redeem stock or redeem subordinated debt, make investments, create liens, enter into leases, sell assets, sell capital stock of subsidiaries, create subsidiaries, guarantee other indebtedness, enter into agreements that restrict dividends from subsidiaries, enter into certain types of swap agreements, enter into gas imbalance or take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, the credit facility requires us to maintain a current ratio, which includes availability, of at least 1.0 to 1.0 and a ratio of total debt to earnings before interest, depreciation, depletion, amortization and income taxes of no more than 4.5 to 1.0. At December 31, 2002, we were in compliance with the covenants contained in our credit facility and could have borrowed the full $225.0 million available under the credit facility.

The 8.75% notes are our unsecured general obligations, are subordinated in right of payment to all of our existing and future senior indebtedness and are jointly and severally guaranteed on a full, unconditional basis by all of our existing and future domestic restricted subsidiaries. The indenture governing the 8.75% notes contains covenants that limit our ability, as well as the ability of our subsidiaries, among other things, to incur additional indebtedness, make certain investments, make restricted payments, sell assets, enter into agreements containing dividends and other payment restrictions affecting subsidiaries, enter into transactions with affiliates, create liens, merge, consolidate and transfer assets and enter into different lines of business. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase. The indenture governing the 8.75% notes permitted the spin-off and the spin-off did not, in itself, constitute a change of control for purposes of the indenture.

The proposed merger with 3TEC does not constitute a change of control for purposes of the indenture. Although we currently believe that no waivers or consents are required under the indenture, we plan to obtain all necessary waivers or consents under the indenture if required.

The 8.75% notes are not redeemable until July 1, 2007. On or after that date they are redeemable, at our option, at 104.375% of the principal amount for the twelve-month period ending June 30, 2008, at 102.917% of the principal amount for the twelve-month period ending June 30, 2009, at 101.458% of the principal amount for the twelve-month period ending June 30, 2010 and at 100% of the principal amount thereafter. In each case, accrued interest is payable to the date of redemption.

We have been assigned a Ba3 senior implied rating and the 8.75% notes have been assigned a B2 rating by Moody's Investor Service Inc. We have also been assigned a BB– corporate credit rating by Standard and Poor's Ratings Group. All of these ratings are below investment grade. As a result, at times we may have difficulty accessing capital markets or raising capital on favorable terms.

As the owner of 100% of our capital stock, Plains Resources made an aggregate of $52.2 million of cash contributions to us from the date of our reorganization to the date of the spin-off. Certain of the contributions were part of the working capital for the upstream assets contributed to us. These contributions increased stockholders' equity by $52.2 million, $5.0 million in the third quarter of 2002 and the remaining $47.2 million in the fourth quarter of 2002. We used these funds to reduce our outstanding debt under our revolving credit facility.

Cash Flows

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 78.8	$ 116.8	$ 79.5
Investing activities	(64.2)	(125.9)	(70.9)
Financing activities	(13.7)	8.5	(13.1)

Net cash provided by operating activities were $78.8 million, $116.8 million and $79.5 million for 2002, 2001 and 2000, respectively. The decrease in 2002 as compared to 2001 is primarily attributable to lower realized prices and increased production costs. The increase in 2001 as compared to 2000 is primarily attributable to higher realized prices in 2001 due to the effects of hedging in 2000.

Net cash used in investing activities were $64.2 million, $125.9 million and $70.9 million for 2002, 2001 and 2000, respectively, and consist primarily of costs incurred in connection with our oil and gas acquisition, development and exploration activities. The 2002 capital expenditure level was reduced from the 2001 amount to manage debt levels and allow flexibility in pursuing acquisition and other opportunities. The capital expenditure amount in 2001 increased from 2000 as we took advantage of higher prices and increased our spending level to advance some of the more technically challenging projects that existed within our property base at the time.

Net cash used in financing activities in 2002 was $13.7 million. Cash receipts in 2002 included proceeds received from the issuance of the 8.75% notes ($196.8 million); cash contributions by Plains Resources ($52.2 million); cash advances from Plains Resources prior to the reorganization ($20.4 million); and net borrowings under the PXP credit facility ($35.8 million). Cash outflows in 2002 included cash distributions to Plains Resources ($312.0 million); payments for debt issuance costs ($5.9 million); and principal payments on long-term debt ($0.5 million). Cash provided by financing activities in 2001 of $8.5 million included cash advances from Plains Resources ($9.0 million) less principal payments on long-term debt ($0.5 million). Cash used in financing activities in 2000 of $13.1 million included repayment of cash advances from Plains Resources ($12.6 million) and principal payments on long-term debt ($0.5 million).

Capital Requirements

We have made and will continue to make substantial capital expenditures for the acquisition, exploitation, development and exploration of oil and gas. During 2003, we expect to make aggregate capital expenditures of approximately $70-$80 million on our existing asset base. In connection with the 3TEC acquisition, we agreed to pay $8.50 in cash and 0.85 of a share of our common stock for each share of 3TEC common stock, subject to certain adjustments based on our common share price prior to closing. We estimate that the cash portion of the acquisition cost will be approximately $288.0 million, consisting of $174.0 million cash paid to 3TEC stockholders, plus the assumption of debt which totaled $99.0 million at December 31, 2002. In addition, we estimate that merger related costs will be approximately $15.0 million, including the cost of obtaining a new credit facility. Capital expenditures for the 3TEC properties are expected to be $55-$60 million pursuant to 3TEC's 2003 capital plan. Based on the foregoing, total capital expenditures for the combined asset base are estimated to be $125-$140 million for 2003. Subsequent to closing the 3TEC acquisition, we may reallocate capital between the two asset bases to optimize 2003 spending. In addition, we intend to continue to pursue the acquisition of underdeveloped producing properties.

On February 27, 2003, we entered into a commitment letter with JP Morgan Chase Bank for a three-year, $500.0 million senior revolving credit facility. The credit facility provides for a borrowing base of $425.0 million that will be redetermined on a semi-annual basis, with the lenders and us each having the right to one annual interim unscheduled redetermination, and adjusted based on our oil and gas properties, reserves, other indebtedness and other relevant factors. Additionally, the credit facility contains a $50.0 million sub-limit on letters of credit. To secure borrowings, we will pledge 100% of the shares of stock of our domestic subsidiaries and will give mortgages covering 80% of the total present value of our domestic oil and gas properties.

Amounts borrowed under this senior revolving credit facility will bear an annual interest rate, at its election, equal to either; (i) the Eurodollar rate, plus from 1.375% to 2.00%; or (ii) the greatest of (1) the prime rate, as determined by JP Morgan Chase Bank, (2) the certificate of deposit rate, plus 1.0%, or (3) the federal funds rate, plus 0.5%; plus an additional 0.125% to .75% for each of (1)-(3). The amount of interest payable on outstanding borrowings will be based on (1) the utilization rate as a percentage of the total amount of funds borrowed under the credit facility to the borrowing base and (2) our long-term debt rating.

We will incur cash expenditures upon the exercise of stock appreciation rights, or SARs, but our outstanding share count will not increase. At December 31, 2002 we had approximately 4.0 million SARs outstanding of which 1.5 million were vested. If all of the vested SARs were exercised, based on $9.75, the price of our common stock as of December 31, 2002, we would pay $2.8 million to holders of the SARs. See "Critical Accounting Policies and Factors that May Affect Future Results—Stock appreciation rights".

Commitments and Contingencies

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	$ 511	$ 511	$35,800	$ —	$—	$200,000
Producing property remediation	1,375	1,225	1,100	700	600	2,150
Operating leases	897	888	858	429	292	445
	$2,783	$2,624	$37,758	$1,129	$892	$202,595

The long-term debt amounts consist principally of amounts due under our credit facility and our 8.75% notes. The obligation for producing property remediation consists of obligations associated with the purchase of certain of our onshore California properties.

Corporate reorganization and spin-off. In connection with our corporate reorganization and spin-off, we entered into certain agreements with Plains Resources. See Items 1 and 2. "Business and Properties—Spin-off Agreements".

Environmental matters. As discussed under "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. However, in some instances, we have received an indemnity in connection with such purchase. There can be no assurance that we will be able to collect on these indemnities. Often these regulations are more burdensome on older properties that were operated before the regulations came into effect such as some of our properties in California and Illinois that have operated for over 90 years. We have established policies for continuing compliance with environmental laws and regulations. We also 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, 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. Typically, when producing oil and gas assets are purchased the purchaser assumes the obligation to plug and abandon wells that are part of such assets. However, in some instances, we received an indemnity with respect to those costs.

We estimate that at December 31, 2002 the costs to perform these tasks (including our commitments related to the purchase of certain of our onshore California properties) will be approximately $0.8 million, net of salvage and other considerations including the fair value of fee lands on which we conduct certain of our production operations ($104.9 million before salvage value and other considerations). Effective January 1, 2003, upon adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations", we will record the fair value of liabilities associated with our asset retirement obligations. See—"Recent Accounting Pronouncements".

We estimate our 2003 cash expenditures related to plugging, abandonment and remediation will be approximately $2.3 million (including the costs required to be expended in connection with the purchase of certain of our onshore California properties). Due to the long life of our onshore reserve base we do not expect our cash outlays for such expenditures for these properties will increase significantly in the next several years. Although our offshore California properties have a shorter reserve life, third parties have retained the majority of the obligations for abandoning these properties.

In connection with the purchase of certain of our onshore California properties, each year we are required to plug and abandon 20% of the then remaining inactive wells (there were 154 inactive wells at December 31, 2002). If we do not meet this commitment, and the requirement is not waived, we must escrow funds to cover the cost of the wells that were not abandoned. To date we have not been required to escrow any funds. In addition, until the end of 2005 we are required to spend at least $600,000 per year (and $300,000 per year from 2006 through 2010) to remediate oil contaminated soil from existing well sites that require remediation.

For a discussion of our specific contractual obligations to incur plugging, abandonment and remediation costs, see "Business—Plugging, Abandonment and Remediation Obligations".

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. 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 under "Legal Proceedings," in the ordinary course of business, we are a claimant and/or defendant in various other legal proceedings. In particular, we are required to indemnify Plains Resources for any liabilities it incurs in connection with a lawsuit it (through a predecessor interest in Stocker Resources, Inc.) has regarding an electric services contract with Commonwealth Energy Corporation. In this lawsuit, Plains Resources is seeking a declaratory judgment that it was entitled to terminate the contract and that Commonwealth has no basis for proceeding against a related $1.5 million performance bond. In a counter suit against Plains Resources, Commonwealth is seeking unspecified damages. We understand that Plains Resources intends to defend its rights vigorously in this matter. 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, oil spills, 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. Our operations in California, including transportation of oil by pipelines within the city and county of Los Angeles, are especially susceptible to damage from earthquakes and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of southern California. 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. We maintain coverage for earthquake damages in California but this coverage may not provide for the full effect of damages that could occur and we may be subject to additional liabilities. 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.

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil and gas 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. The contract counterparties for our derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better. Three of the financial institutions are participating lenders in our credit facility, with one such counterparty holding contracts that represent approximately 33% of the fair value of all of our open positions at December 31, 2002.

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 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 and gas production which could have a negative impact on future results of operations or cash flows.

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 and gas have historically been volatile. Decreases in oil and gas 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 and gas prices and our hedging programs, see "Item 7A—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 and gas production at the oil and gas 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 and gas prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will change in the near term. If oil and gas prices decline significantly 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.

Oil and gas reserves. Our proved reserve information is 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 PV-10 or the standardized measure 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.

A large portion of our proved reserve base (approximately 95% at December 31, 2002) is comprised of oil properties that are sensitive to oil price volatility. Historically, we have experienced significant upward and downward revisions to our proved reserve 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 proved 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.

Stock appreciation rights. At the time of the spin-off, pursuant to our employee matters agreement with Plains Resources, all outstanding options to acquire Plains Resources common stock at the time of the spin-off were "split" into (1) an equal number of options to acquire Plains Resources common stock and (2) an equal number of SARs, with respect to our common stock. The exercise price of the original Plains Resources stock options was also "split" between the new Plains Resources stock options and the SARs based on the following relative amounts: the closing price (with dividend) of Plains Resources common stock on the spin-off date ($23.05 per share) less the closing price (on a "when-issued" basis) of our common stock on the spin-off date ($9.10 per share), both as reported on the NYSE, and such closing price of our common stock.

SARs are subject to variable accounting treatment under U.S. generally accepted accounting principles. As a result, at the end of each quarter, we will compare the closing price of our common stock on the last day of the quarter to the exercise price of each outstanding or unexercised SAR that is vested or for accounting purposes is deemed vested at the end of the quarter. For example, if a SAR is scheduled to vest on December 31, for accounting purposes one-fourth of the shares are deemed to vest at the end of each quarter of that year even though no vesting legally occurs until December 31. To the extent the closing price at the end of each quarter exceeds the exercise price of each SAR, we will recognize such excess as an accounting charge for the SARs deemed vested to the extent such excess has not previously been recognized as expense. If the quarter-end closing price decreases compared to prior periods, we will recognize credits to income, to the extent we have previously recognized expense. These quarterly charges and credits will make our results of operations depend, in part, on fluctuations in the price of our common stock and could have a material adverse effect on our results of operations. We will incur cash expenditures as SARs are exercised, but our common share count will not increase.

We recognized compensation expense of $2.7 million, representing the difference in our common stock price on December 18, 2002, the date of the spin-off, and the exercise price of each SAR deemed vested on that date. In addition, we recognized compensation expense of $1.0 million, representing the increase in our stock price and the vesting deemed to have occurred from the spin-off date to December 31, 2002. As of December 31, 2002, we had approximately 4.0 million SARs outstanding with an average exercise price of $8.68, of which 2.6 million of the SARs were deemed vested.

Recent Accounting Pronouncements

Statement of Accounting Standards, or SFAS, No. 143, "Accounting for Asset Retirement Obligations" became 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, or ARO, for oil and gas properties and equipment is approximately $26.5 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 $20.2 million (reflecting a $30.8 million decrease in accumulated DD&A, partially offset by $10.6 million in accretion expense), $12.3 million net of taxes. We estimate that we will record a liability of $26.5 million and an asset of $15.9 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 have no effect on our financial statements.

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 in 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, 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 required disclosures are included in our 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.

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

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. 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 ("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 Stockholders' Equity. 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 and gas 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 and gas revenues in the period in which they occur. No ineffectiveness was recognized in 2002 or 2001.

At December 31, 2001, OCI consisted of $26.6 million ($15.9 million, net of tax) of unrealized gains on our open oil hedging instruments. As oil prices increased significantly during 2002, the fair value of our open oil hedging positions decreased $62.3 million ($37.3 million, net of tax). At December 31, 2002, OCI consisted of $20.9 million ($12.6 million net of tax) of unrealized losses on our crude oil hedging instruments, $0.3 million ($0.2 million, net of tax) loss related to our interest rate swap and $0.2 million ($0.1 million, net of tax) related to pension liabilities. At December 31, 2002, the assets and liabilities related to our open oil hedging instruments were included in current assets ($2.6 million), other assets ($1.4 million), current liabilities ($24.4 million), other long-term liabilities ($0.6 million) and deferred income taxes (a tax benefit of $8.4 million).

During 2002, $14.7 million ($8.9 million net of tax) in losses from the settlement of oil hedging instruments were reclassified from OCI and charged to income as a reduction of oil sales revenues. Oil sales revenues for the period have also been reduced by a $0.9 million non-cash expense related to the amortization of option premiums. As of December 31, 2002, $21.8 million ($13.1 million, net of tax) of deferred net losses on derivative instruments recorded in OCI are expected to be reclassified to earnings during the next twelve-month period.

Commodity price risk. As of March 1, 2003, we had the following open oil hedge positions with respect to our oil properties:

	Barrels per Day		
	2003	2004	2005
Swaps			
Average price $23.81/bbl	19,250	—	—
Average price $23.82/bbl	—	17,500	—
Average price $23.57/bbl	—	—	5,000

Assuming our fourth quarter 2002 production volumes are held constant in subsequent periods, these positions result in us hedging approximately 75%, 69% and 20% of oil production in 2003, 2004 and 2005, 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 settlements 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 and gas sales revenues. These contracts resulted in an increase (decrease) in revenues of $(15.6) million, $0.3 million and $(72.8) million for the years ended December 31, 2002, 2001 and 2000, respectively. As of December 31, 2002 we had an unrealized loss of $20.9 million ($12.6 million, net of tax) with respect to these contracts. The estimated fair value of the hedges is included in our balance sheet as of December 31, 2002.

Our average realized price for oil is sensitive to changes in location and qualify differential adjustments as set forth in our oil sales contracts. At December 31, 2002 we had basis risk swap contracts on our Illinois Basin production through September 30, 2003. The swaps fix the location differential portion of 2,600 barrels per day at $0.43, $0.57 and $0.39 per barrel for the first, second and third quarters of 2003, respectively.

The fair value of outstanding crude oil derivative commodity instruments and the change in fair value that would be expected from a 10% 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	$(20.9)	$29.3	$27.4	$17.7

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 period 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% 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% 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.

The contract counterparties for our derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better. Three of the financial institutions are participating lenders in our revolving credit facility, with one counterparty holding contracts that represent approximately 33% of the fair value of all open positions as of December 31, 2002.

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 revenues on the hedged volumes than we would receive in the absence of hedges.

Interest rate risk. Our credit facility is sensitive to market fluctuations in interest rates. We use interest rate swaps to hedge underlying debt obligations. These instruments hedge specific debt issuances and qualify for hedge accounting. The interest rate differential is reflected as an adjustment to interest expense over the life of the instruments. We have entered into an interest rate swap for an aggregate notional principal amount of $7.5 million that fixes the interest rate on that amount of borrowing under our credit facility at 3.9% plus the LIBOR margin set forth in our credit facility. The swap expires in October 2004.

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.

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 Chairman of the Board and 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 Chairman of the Board and 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.

(a) (3) Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated February 2, 2003 between Plains Exploration & Production Company and 3TEC Energy Corporation (incorporated by reference to Exhibit 10.1 to Plains' Current Report on Form 8-K filed on February 3, 2003).
3.1	Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
3.2	Bylaws (incorporated by reference to Exhibit 3.2 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002)
4.2	Indenture dated July 3, 2002 among Plains Exploration & Production Company, L.P., Plains E&P Company, the Subsidiary Guarantors parties thereto, and JPMorgan Chase Bank, as Trustee (incorporated by reference to Exhibit 4.2 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
4.3	Form of 8 3/4% Senior Subordinated Note (included in Exhibit 4.2).
4.4	Registration Rights Agreement dated July 3, 2002 among Plains Exploration & Production Company, L.P., Plains E&P Company, Arguello Inc. and Plains Illinois (incorporated by reference to Exhibit 4.4 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.1	Master Separation Agreement dated July 3, 2002 between Plains Exploration & Production Company, L.P. and Plains Resources Inc. (incorporated by reference to Exhibit 10.1 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.2	Plains Exploration & Production Company, L.P. Transition Services Agreement dated July 3, 2002 between Plains Exploration & Production Company, L.P. and Plains Resources Inc. (incorporated by reference to Exhibit 10.2 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.3	Extension of Term of Plains Exploration & Production Company Transition Services Agreement, dated as of December 18, 2002, between Plains Exploration & Production Company and Plains Resources Inc. (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-4 filed on February 12, 2003).
10.4	Plains Resources Inc. Transition Services Agreement dated July 3, 2002 between Plains Resources Inc. and Plains Exploration & Production Company, L.P. (incorporated by reference to Exhibit 10.3 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.5	Second Amended and Restated Tax Allocation Agreement dated November 20, 2002 between Plains Exploration & Production Company and Plains Resources Inc. (incorporated by reference to Exhibit 10.4 to the Company's Amendment No. 2 to Form 10 filed on December 3, 2002)

Exhibit Number	Description
10.6	Technical Services Agreement dated July 3, 2002 between Plains Exploration & Production Company, L.P. and Plains Resources Inc. (incorporated by reference to Exhibit 10.5 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.7	Intellectual Property Agreement dated July 3, 2002 between Plains Exploration & Production Company, L.P. and Plains Resources Inc. (incorporated by reference to Exhibit 10.6 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.8	Employee Matters Agreement dated July 3, 2002 between Plains Exploration & Production Company, L.P. and Plains Resources Inc. (incorporated by reference to Exhibit 10.7 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.9	Purchase and Sale Agreement dated June 4, 1999, by and among Plains Resources Inc., Chevron U.S.A., Inc., and Chevron Pipe Line Company (incorporated by reference to Exhibit 10.7 to the Company's Form S-1 filed on June 21, 2002).
10.10	Crude Oil Marketing Agreement dated as of November 23, 1998 among Plains Resources Inc., Plains Illinois Inc., Stocker Resources, L.P., Calumet Florida, Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.8 to the Company's Form S-1 filed on June 21, 2002).
10.11	Letter Agreement dated as of October 23, 2001 by and between Plains Marketing, L.P. and Stocker Resources, L.P. (incorporated by reference to Exhibit 10.9 to the Company's Form S-1 filed on June 21, 2002).
10.12	Credit Agreement dated July 3, 2002 among Plains Exploration & Production Company, L.P., JPMorgan Chase Bank, as Administrative Agent, Bank One, NA (Main Office Chicago) and Fleet National Bank, as Syndication Agents, BNP Paribas and Fortis Capital Corp., as Documentation Agents, and the Lenders party thereto (incorporated by reference to Exhibit 10.11 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.13	First Amendment, effective as of July 19, 2002, to Credit Agreement dated as of July 3, 2002 among Plains Exploration & Production Company, L.P., as Borrower, JPMorgan Chase Bank, as administrative agent, Bank One, NA and Fleet National Bank, as Syndication Agents, BNP Paribas and Fortis Capital Corp., as Documentation Agents, and the Lenders party thereto (incorporated by reference to Exhibit 10.12 to the Company's Amendment No. 1 to Form S-1 filed on August 28, 2002).
10.14	Employment Agreement, dated as of September 19, 2002, between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.13 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
10.15	Employment Agreement, dated as of September 19, 2002, between Plains Exploration & Production Company and John T. Raymond (incorporated by reference to Exhibit 10.14 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
10.16	Employment Letter Agreement, dated as of August 20, 2002, between Plains Exploration & Production Company and Stephen A. Thorington (incorporated by reference to Exhibit 10.15 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
10.17	Employment Letter Agreement, dated as of September 19, 2002, between Plains Exploration & Production Company and Timothy T. Stephens (incorporated by reference to Exhibit 10.16 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
10.18*	Form of Plains Stock Appreciation Rights Agreement.
10.19*	Form of Plains Restricted Stock Award Agreement.

Exhibit Number	Description
10.20	Plains Exploration & Production Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.21 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.21	Amendment No. 1 to Employee Matters Agreement, dated as of September 18, 2002, between Plains Resources Inc. and Plains Exploration & Production Company (incorporated by reference to Exhibit 10.22 to the Company's Amendment No. 2 to Form S-1 filed on October 4, 2002).
10.22	Amendment No. 1 to Master Separation Agreement, dated as of November 20, 2002, between Plains Resources Inc. and Plains Exploration & Production Company (incorporated by reference to Exhibit 10.24 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.23	Amendment No. 2 to Employee Matters Agreement, dated as of November 20, 2002, between Plains Resources Inc. and Plains Exploration & Production Company (incorporated by reference to Exhibit 10.25 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.24	Amendment No. 3 to Employee Matters Agreement, dated as of December 2, 2002, between Plains Exploration & Production Company and Plains Resources Inc. (incorporated by reference to Exhibit 10.23 to the Company's Registration Statement on Form S-4 filed on February 12, 2003).
10.25	Amendment No. 1 to Employment Agreement, dated as of November 20, 2002, between Plains Exploration & Production Company and James C. Flores (incorporated by reference to Exhibit 10.26 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.26	Amendment No. 1 to Employment Agreement, dated as of November 20 , 2002, between Plains Exploration & Production Company and John T. Raymond (incorporated by reference to Exhibit 10.27 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.27	Amendment No. 1 to Employment Letter Agreement, dated as of November 20 , 2002, between Plains Exploration & Production Company and Stephen A. Thorington (incorporated by reference to Exhibit 10.28 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.28	Plains Exploration & Production Company 2002 Transition Stock Incentive Plan (incorporated by reference to Exhibit 10.33 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.29	Plains Exploration & Production Company 2002 Rollover Stock Incentive Plan (incorporated by reference to Exhibit 10.34 to the Company's Amendment No. 1 to Form 10 filed on December 3, 2002).
10.30	Voting Agreement dated as of February 2, 2003, by and among Plains Exploration & Production Company, 3TEC Energy Corporation, EnCap Energy Acquisition III-B, Inc., EnCap Energy Capital Fund III, L.P., BOCP Energy Partners, L.P., ECIC Corporation, Floyd C. Wilson, Stephen W. Herod, and R.A. Walker (incorporated by reference to Exhibit 10.2 to Plains' Current Report on Form 8-K filed on February 3, 2003).
10.31	Voting Agreement dated as of February 2, 2003, by and among Plains Exploration & Production Company, 3TEC Energy Corporation, EnCap Energy Capital Fund III-B, L.P., EnCap Energy Capital Fund III, L.P., BOCP Energy Partners, L.P., Energy Capital Investment Company PLC, Sable Management, L.P., and James C. Flores (incorporated by reference to Exhibit 10.3 to Plains' Current Report on Form 8-K filed on February 3, 2003).

Exhibit Number	Description
10.32	Registration Rights Agreement dated February 2, 2003, by and among Plains Exploration & Production Company, EnCap Energy Capital Fund III, L.P., EnCap Energy Acquisition III-B, Inc., BOCP Energy Partners, L.P., ECIC Corporation and EnCap Investments L.L.C. (incorporated by reference to Exhibit 10.4 to Plains' Current Report on Form 8-K filed on February 3, 2003).
10.33*	Form of Plains Restricted Stock Unit Agreement.
10.34*	First Amendment to Plains Exploration & Production Company 2002 Stock Incentive Plan.
21.1*	Subsidiaries of Plains Exploration & Production Company.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell and Associates, Inc.
23.3*	Consent of Ryder Scott Company
23.4*	Consent of H. J. Gruy and Associates, Inc.
99.1	Supplemental Tax Letter (incorporated by reference to Exhibit 99.2 to the Company's Amendment No. 2 to Form 10 filed on December 3, 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 3, 2003 with respect to the Company's proposed acquisition of 3TEC Energy Corporation.

A Current Report on Form 8-K was filed on February 20, 2003 with respect to current estimates of certain results for 2003.

A Current Report on Form 8-K was filed on February 21, 2003 with respect to the Company's press release reporting 2002 earnings and December 31, 2002 oil and gas reserve information.

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 EXPLORATION & PRODUCTION COMPANY

Date: March 26, 2003	By: /s/ STEPHEN A. THORINGTON Stephen A. Thorington, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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.

Date: March 26, 2003	By: /s/ JAMES C. FLORES James C. Flores, Chairman of the Board and Chief Executive Officer (Principal Financial Officer)
Date: March 26, 2003	By: /s/ ALAN R. BUCKWALTER, III Alan R. Buckwalter, III, Director
Date: March 26, 2003	By: /s/ JERRY L. DEES Jerry L. Dees, Director
Date: March 26, 2003	By: /s/ TOM H. DELIMITROS Tom H. Delimitros, Director
Date: March 26, 2003	By: /s/ JOHN H. Lollar John H. Lollar, Director
Date: March 26, 2003	By: /s/ STEPHEN A. THORINGTON Stephen A. Thorington, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: March 26, 2003	By: /s/ CYNTHIA A. FEEBACK Cynthia A. Feeback, Senior Vice President - Accounting and Treasurer (Principal Accounting Officer)

CERTIFICATION

I, James C. Flores, Chief Executive Officer of Plains Exploration & Production Company, certify that:

1. I have reviewed this annual report on Form 10-K of Plains Exploration & Production Company;

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.

Date: March 26, 2003

/s/ JAMES C. FLORES
Name: James C. Flores
Title: Chairman of the Board and Chief Executive Officer

CERTIFICATION

I, Stephen A. Thorington, Chief Financial Officer of Plains Exploration & Production Company, certify that:

1. I have reviewed this annual report on Form 10-K of Plains Exploration & Production Company;

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.

Date: March 26, 2003

/s/ STEPHEN A. THORINGTON
Name: Stephen A. Thorington
Title: Executive Vice President and
Chief Financial Officer

PLAINS EXPLORATION & PRODUCTION COMPANY

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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 of Plains Exploration & Production Company

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Plains Exploration & Production Company 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 2 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments and hedging activities, effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
March 10, 2003

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED BALANCE SHEETS

(in thousands of dollars)

	December 31, 2002	December 31, 2001
ASSETS		
Current Assets		
Cash and cash equivalents	$ 1,028	$ 13
Accounts receivable—Plains All American Pipeline, L.P.	22,943	12,331
Other accounts receivable	5,925	3,091
Commodity hedging contracts	2,594	21,787
Inventories	5,198	4,629
Other current assets	1,051	960
	38,739	42,811
Property and Equipment, at cost		
Oil and natural gas properties—full cost method		
Subject to amortization	629,454	561,034
Not subject to amortization	30,045	33,371
Other property and equipment	2,207	1,516
	661,706	595,921
Less allowance for depreciation, depletion and amortization	(168,494)	(140,804)
	493,212	455,117
Other Assets	18,929	18,827
	$ 550,880	$ 516,755
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and other current liabilities	$ 38,577	$ 34,056
Commodity hedging contracts	24,572	—
Royalties payable	11,873	7,271
Interest payable	9,207	41
Payable to Plains Resources Inc.	1,435	—
Current maturities of long-term debt	511	511
	86,175	41,879
Payable to Plains Resources Inc.	—	235,161
Long-Term Debt		
8.75% Senior Subordinated Notes	196,855	—
Revolving credit facility	35,800	—
Other	511	1,022
	233,166	1,022
Other Long-Term Liabilities	6,303	1,413
Deferred Income Taxes	51,416	57,193
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common stock, $0.01 par value, 100,000,000 shares authorized, 24,224,448 shares issued and outstanding	244	—
Additional paid-in capital	174,279	—
Retained earnings	12,155	—
Combined owner's equity	—	164,203
Accumulated other comprehensive income	(12,858)	15,884
	173,820	180,087
	$ 550,880	$ 516,755

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF INCOME

(in thousands of dollars, except per share data)

	Year Ended December 31,		
	2002	2001	2000
Revenues			
Oil sales to Plains All American Pipeline, L.P.	$178,038	$174,895	$126,434
Gas sales	10,299	28,771	16,017
Other operating revenues	226	473	—
	188,563	204,139	142,451
Costs and Expenses			
Production expenses	78,451	63,795	56,228
General and administrative			
Stock appreciation rights	3,653	—	—
Spin-off costs	777	—	—
Other	10,756	10,210	6,308
Depreciation, depletion and amortization	30,359	24,105	18,859
	123,996	98,110	81,395
Income from Operations	64,567	106,029	61,056
Other Income (Expense)			
Expenses of terminated public equity offering	(2,395)	—	—
Interest expense	(19,377)	(17,411)	(15,885)
Interest and other income	174	463	343
Income Before Income Taxes and Cumulative Effect of Accounting Change	42,969	89,081	45,514
Income tax expense			
Current	(6,353)	(6,014)	(2,431)
Deferred	(10,379)	(28,374)	(14,334)
Income Before Cumulative Effect of Accounting Change	26,237	54,693	28,749
Cumulative effect of accounting change, net of tax benefit	—	(1,522)	—
Net Income	$ 26,237	$ 53,171	$ 28,749
Basic and Diluted Earnings Per Share			
Income before cumulative effect of accounting change	$ 1.08	$ 2.26	$ 1.19
Cumulative effect of accounting change	—	(0.06)	—
Net income	$ 1.08	$ 2.20	$ 1.19
Weighted Average Shares Outstanding			
Basic	24,193	24,200	24,200
Diluted	24,201	24,200	24,200

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands of dollars)

	Year Ended December 31,		
	2002	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 26,237	$ 53,171	$ 28,749
Items not affecting cash flows from operating activities			
Depreciation, depletion and amortization	30,359	24,105	18,859
Deferred income taxes	10,379	28,374	14,334
Cumulative effect of adoption of accounting change	—	1,522	—
Change in derivative fair value	—	1,055	—
Other noncash items	457	996	—
Change in assets and liabilities from operating activities			
Accounts receivable and other assets	(11,964)	9,197	7,597
Inventories	(576)	(591)	(195)
Payable to Plains Resources Inc.	4,946	—	—
Accounts payable and other liabilities	18,988	(1,021)	10,120
Net cash provided by operating activities	78,826	116,808	79,464
CASH FLOWS FROM INVESTING ACTIVITIES			
Acquisition, exploration and development costs	(64,497)	(125,753)	(70,505)
Additions to other property and equipment	(190)	(127)	(366)
Proceeds from property sales	529	—	—
Net cash used in investing activities	(64,158)	(125,880)	(70,871)
CASH FLOWS FROM FINANCING ACTIVITIES			
Principal payments of long-term debt	(511)	(511)	(511)
Change in revolving credit facility	35,800	—	—
Proceeds from debt issuance	196,752	—	—
Debt issuance costs	(5,936)	—	—
Contribution from Plains Resources Inc.	52,200	—	—
Distribution to Plains Resources Inc.	(311,964)	—	—
Receipts from (payments to) Plains Resources Inc.	20,363	9,060	(12,621)
Other	(357)	—	—
Net cash provided by (used in) financing activities	(13,653)	8,549	(13,132)
Net increase (decrease) in cash and cash equivalents	1,015	(523)	(4,539)
Cash and cash equivalents, beginning of period	13	536	5,075
Cash and cash equivalents, end of period	$ 1,028	$ 13	$ 536

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands of dollars)

	Year Ended December 31,		
	2002	2001	2000
Net Income	$ 26,237	$53,171	$28,749
Other Comprehensive Income (Loss)			
Commodity hedging contracts:			
Cumulative effect of accounting change, net of taxes 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	—
Comprehensive Income (Loss)	$ (2,505)	$69,055	$28,749

See notes to consolidated financial statements.

PLAINS EXPLORATION AND PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(share and dollar amounts in thousands)

	Combined Owner's Equity	Common Stock Shares	Common Stock Amount	Additional Capital Paid-in	Contribution Receivable	Retained Earnings	Accumulated Other Comprehensive Income	Total
Balance at December 31, 1999	$ 82,283	—	$—	$ —	$ —	$ —	$ —	$ 82,283
Net income	28,749	—	—	—	—	—	—	28,749
Other comprehensive income	—	—	—	—	—	—	—	—
Balance at December 31, 2000	111,032	—	—	—	—	—	—	111,032
Net income	53,171	—	—	—	—	—	—	53,171
Other comprehensive income	—	—	—	—	—	—	15,884	15,884
Balance at December 31, 2001	164,203	—	—	—	—	—	15,884	180,087
Net income	14,082	—	—	—	—	12,155	—	26,237
Contribution of amounts due to Plains Resources Inc.	255,991	—	—	—	—	—	—	255,991
Distribution to Plains Resources Inc.	(311,964)	—	—	—	—	—	—	(311,964)
Cash contribution by Plains Resources Inc.	5,000	—	—	—	—	—	—	5,000
Incorporation and capitalization of Plains Exploration & Production Company	(127,312)	24,200	242	127,070	—	—	—	—
Contributions by Plains Resources Inc.								
Cash	—	—	—	47,200	—	—	—	47,200
Receivable	—	—	—	510	(510)	—	—	—
Other	—	—	—	4,314	—	—	—	4,314
Spin-off by Plains Resources Inc.	—	(141)	—	(4,335)	—	—	—	(4,335)
Restricted stock awards								
Issuance of restricted stock	—	165	2	1,500	—	—	—	1,502
Deferred compensation	—	—	—	(1,470)	—	—	—	(1,470)
Other comprehensive income	—	—	—	—	—	—	(28,742)	(28,742)
Balance at December 31, 2002	$ —	24,224	$244	$174,789	$(510)	$12,155	$(12,858)	$173,820

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Significant Accounting Policies

Organization

The consolidated financial statements of Plains Exploration & Production Company ("PXP", "us", "our", or "we") include the accounts of our wholly-owned subsidiaries Arguello Inc., Plains Illinois, Inc. and other immaterial subsidiaries. We are a Delaware corporation that was converted from a limited partnership in September 2002. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to prior year statements to conform to the current year presentation.

We are an independent energy company that is 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.

Under the terms of a Master Separation Agreement between us and Plains Resources, on July 3, 2002 Plains Resources contributed to us: (i) 100% of the capital stock of its wholly owned subsidiaries that own oil and gas properties offshore California and in Illinois; and (ii) all amounts payable to it by us and our subsidiary companies (the "reorganization"). The contribution of the amounts payable to Plains Resources is reflected in Stockholders' Equity.

On July 3, 2002 we issued $200.0 million of 8.75% Senior Subordinated Notes due 2012 (the "8.75% Notes") and entered into a $300.0 million revolving credit facility. The net proceeds from the 8.75% notes, $195.3 million, and $116.7 million borrowed under the credit facility were used to pay a $312.0 million cash distribution to Plains Resources.

Effective at the time of the reorganization we assumed direct ownership and control of Arguello Inc., Plains Illinois, Inc., and two other subsidiaries. Accordingly, for periods subsequent to the reorganization, the financial information is presented on a consolidated basis. For periods prior to the reorganization, the historical operations of the businesses owned by PXP, Arguello Inc., Plains Illinois, Inc. and the two other subsidiaries, all previously referred to as the Upstream Subsidiaries of Plains Resources Inc., were presented on a carve-out combined basis since no direct owner relationship existed among the various operations comprising these businesses. Accordingly, Plains Resources' net investment in the businesses (combined owners' equity) was shown in lieu of stockholder's equity in the historical financial statements.

In June 2002 we filed a registration statement on Form S-1 with the Securities and Exchange Commission for the initial public offering (the "IPO"), of our common stock. We terminated the IPO in October 2002, primarily due to market conditions. As a result, costs and expenses of $2.4 million incurred in connection with the IPO were charged to expense during 2002.

In September 2002 we were capitalized with 24.2 million shares of common stock, all of which were owned by Plains Resources. As a result of the capitalization, Combined Owners Equity as of June 30, 2002 was reclassified between Common Stock and Additional Paid-in Capital. Retained Earnings at December 31, 2002 represents our earnings from June 30, 2002 through December 31, 2002.

On December 18, 2002 Plains Resources distributed 24.1 million of the issued and outstanding shares of our common stock to the holders of Plains Resources' common stock on the basis of one share of our common stock for every one share of Plains Resources common stock held as of the close of business on December 11, 2002 (the "spin-off") and contributed 0.1 million shares of our common stock to us. Prior to the spin-off Plains Resources made a $52.2 million in cash capital contribution to us and transferred to us certain assets and liabilities of Plains Resources ($4.3 million, net), primarily related to land, unproved oil and gas properties, office equipment and pension obligations. In addition, as a result of the spin-off certain tax attributes previously considered in the deferred income tax liabilities allocated to us ($4.3 million) and recognized in our financial statements remained with Plains Resources. The cash contributions, the transfer of assets and the assumption of certain liabilities by us and the effect of the increase in our deferred tax liabilities are reflected in Additional Paid-in Capital in Stockholders' Equity.

These financial statements include allocations of direct and indirect corporate and administrative costs of Plains Resources made prior to the reorganization. The methods by which such costs were estimated and allocated to us were deemed reasonable by Plains Resources' management; however, such allocations and estimates are not necessarily indicative of the costs and expenses that would have been incurred had we operated as a separate entity. Allocations of such costs are considered to be related party transactions and are discussed in Note 4.

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 natural gas reserves. The costs of unproved properties are excluded from amortization until the properties are evaluated. Interest is capitalized on oil and natural gas properties not subject to amortization and in the process of development. Proceeds from the sale of oil and natural 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 natural 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 is recorded at cost and consists primarily of office furniture and fixtures and computer hardware and software. Acquisitions, renewals, and betterments are capitalized; maintenance and repairs are expensed. Depreciation is provided using the straight-line method over estimated useful lives of three to seven years. 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 natural gas reserves, (2) depreciation, depletion and amortization, including future abandonment costs, (3) income taxes 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 one institution and at times may exceed federally insured limits. We periodically assess the financial condition of the institution and believe that any possible credit risk is minimal.

Inventory. Oil inventories are carried at the lower of the cost to produce or market value. Materials and supplies inventory is stated at the lower of cost or market with cost determined on an average cost method. Inventory consists of the following (in thousands):

	December 31,	
	2002	2001
Oil	$ 730	$ 428
Materials and supplies	4,468	4,201
	$5,198	$4,629

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

	December 31,	
	2002	2001
Land	$ 8,853	$ 8,103
Commodity hedging contracts	1,432	5,627
Debt issue costs, net	5,485	—
Other	3,159	5,097
	$18,929	$18,827

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 likely than not that the related tax benefits will not be realized.

Under the terms of a tax allocation agreement, our taxable income or loss prior to the spin-off is included in the consolidated income tax returns filed by Plains Resources. 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 Plains Resources during the period in which we are included in Plains Resources' consolidated group, we could be liable if any federal tax liability is incurred, but not discharged, by any other member of Plains Resources' consolidated group. In addition, to the extent Plains Resources' net operating losses are used in the consolidated return to offset our taxable income during the period January 1, 2002 through the spin-off, we will reimburse Plains Resources 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. Such amount will be paid to Plains Resources in periods in which it makes federal income tax payments.

Income tax obligations reflected in these financial statements are calculated assuming we filed a separate consolidated income tax return. Income taxes currently payable at December 31, 2001, which were forgiven in the reorganization, are included in Payable to Plains Resources in the consolidated balance sheet at December 31,2001. At December 31, 2002 current liabilities and other long-term liabilities include $0.2 million and $3.2 million, respectively, of income taxes payable to Plains Resources with respect to periods subsequent to the reorganization and the reimbursement due Plains Resources with respect to state taxes and the utilization of net operating losses.

Revenue Recognition. Oil and gas revenue from our interests in producing wells is recognized when the production is delivered and the title transfers.

Derivative Financial Instruments (Hedging). We utilize 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. See Note 2.

Stock Based Compensation. We account for stock based compensation using the intrinsic value method. See Note 6.

Earnings Per Share. In September 2002 we were capitalized with 24,200,000 shares of common stock, all of which were owned by Plains Resources. In accordance with SEC Staff Accounting Bulletin No. 98, this capitalization has been retroactively reflected for purposes for calculating earnings per share for the years ended December 31, 2001 and 2000. The weighted average shares outstanding for computing both basic and diluted earnings per share was 24,200,000 shares for the years ended December 31, 2001 and 2000. For the year ended December 31, 2002 weighted average shares outstanding for computing basic and diluted earnings per share were 24,193,000 and 24,201,000, respectively. In computing EPS, no adjustments were made to reported net income, and no potential common stock existed during the periods.

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 $26.5 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 $20.2 million (reflecting a $30.8 million decrease in accumulated depreciation, depletion and amortization, partially offset by $10.6 million in accretion expense), $12.3 million net of taxes. We estimate that we will record a liability of $26.5 million and an asset of $15.9 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 have no effect on our financial statements.

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 in 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, 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 consolidated 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.

Note 2—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 gain of $7.0 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 $9.7 million and $4.2 million, respectively, and a net-of-tax non-cash charge of $1.5 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 and gas 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 and gas revenues in the period in which they occur. No ineffectiveness was recognized in 2002 or 2001.

Unrealized gains and losses on hedging instruments reflected in OCI, and adjustments to carrying amounts on hedged volumes, are included in oil and gas revenues in the period that the related volumes are delivered. Gains and losses of hedging instruments that represent hedge ineffectiveness, as well as any amounts excluded from the assessment of hedge effectiveness, are recognized currently in oil and gas revenues. For purposes of our combined 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 and gas revenues for the year ended December 31, 2001 include a $3.1 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 consisted of $26.6 million ($15.9 million, net of tax) of unrealized gains on our open oil hedging instruments. As oil prices increased significantly during 2002, the fair value of our open oil hedging positions decreased $62.3 million ($37.3 million, net of tax). At December 31, 2002, OCI consisted of $20.9 million ($12.6 million net of tax) of unrealized losses on our oil hedging instruments, $0.3 million ($0.2 million, net of tax) loss related to our interest rate swap and $0.2 million ($0.1 million, net of tax) related to pension liabilities. At December 31, 2002, the assets and liabilities related to our open oil hedging instruments were included in current assets ($2.6 million), other assets ($1.4 million), current liabilities ($24.4 million), other long-term liabilities ($0.6 million) and deferred income taxes (a tax benefit of $8.4 million).

During 2002, $14.7 million ($8.9 million net of tax) in losses from the settlement of oil hedging instruments were reclassified from OCI and charged to income as a reduction of oil sales revenues. Oil sales revenues for the period have also been reduced by a $0.9 million non-cash expense related to the amortization of option premiums. As of December 31, 2002, $21.8 million ($13.1 million, net of tax) of deferred net losses on derivative instruments recorded in OCI are expected to be reclassified to earnings during the next twelve-month period.

Our average realized price for oil is sensitive to changes in location and quality differential adjustments as set forth in our oil sales contracts. At December 31, 2002 we had basis risk swap contracts on our Illinois Basin production through September 30, 2003. The swaps fix the location differential portion of 2,600 barrels per day at $0.43, $0.57 and $0.39 per barrel for the first, second and third quarters of 2003, respectively.

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

	Bbls Per Day	
	2003	2004
Swaps		
Average price $23.81 per Bbl	19,250	—
Average price $23.53 per Bbl	—	12,500

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.

We utilize interest rate swaps to manage the interest rate exposure on our long-term debt. We currently have an interest rate swap agreement that expires in October 2004, under which we receive LIBOR and pay 3.9% on a notional amount of $7.5 million. The interest rate swap fixes the interest rate on $7.5 million of borrowings under our credit facility at 3.9% plus the LIBOR margin set forth in the credit facility (5.3% at December 31, 2002).

Note 3—Long-Term Debt

At December 31, 2002 long-term debt consisted of:

	Current	Long-Term
Revolving credit facility	$—	$ 35,800
8.75% senior subordinated notes, net of unamortized discount of $3.1 million	—	196,855
Other	511	511
	$511	$233,166

Revolving credit facility

As of December 31, 2002 we had $35.8 million in borrowings, bearing interest at 3.0% and $5.2 million in letters of credit outstanding under our $300.0 million revolving credit facility. The credit facility provides for a borrowing base of $225.0 million that will be reviewed every six months, with the lenders and us each having the right to one annual interim unscheduled redetermination, and adjusted based on our oil and gas properties, reserves, other indebtedness and other relevant factors, and matures in 2005. The credit facility contains a $30.0 million sub-limit on letters of credit. To secure borrowings, we pledged 100% of the shares of stock of our domestic subsidiaries, who also guaranteed payments under the credit facility, and gave mortgages covering 80% of the total present value of our domestic oil and gas properties.

Amounts borrowed under the credit facility bear an annual interest rate, at our election, equal to either: (i) the Eurodollar rate, plus from 1.375% to 1.75%; or (ii) the greatest of (1) the prime rate, as determined by JPMorgan Chase Bank, (2) the certificate of deposit rate, plus 1.0%, or (3) the federal funds rate, plus 0.5%; plus an additional 0.125% to 0.5% for each of (1)-(3). The amount of interest payable on outstanding borrowings is based on (1) the utilization rate as a percentage of the total amount of funds borrowed under the credit facility to the borrowing base and (2) our long-term debt rating. Commitment fees and letter of credit fees under the credit facility are based on the utilization rate and long-term debt rating. Commitment fees range from 0.375% to 0.5% of the unused portion of the borrowing base. Letter of credit fees range from 1.375% to 1.75%. The issuer of any letter of credit receives an issuing fee of 0.125% of the undrawn amount. In 2002 we made cash payments for interest and fees totalling $1.2 million.

The credit facility contains negative covenants that limit our ability, as well as the ability of our subsidiaries, among other things, to incur additional debt, pay dividends on stock, make distributions of cash or property, change the nature of our business or operations, redeem stock or redeem subordinated debt, make investments, create liens, enter into leases, sell assets, sell capital stock of subsidiaries, create subsidiaries, guarantee other indebtedness, enter into agreements that restrict dividends from subsidiaries, enter into certain types of swap agreements, enter into gas imbalance or take-or-pay arrangements, merge or consolidate and enter into transactions with affiliates. In addition, the credit facility requires us to maintain a current ratio, which includes availability, of at least 1.0 to 1.0 and a ratio of total debt to earnings before interest, depreciation, depletion, amortization and income taxes of no more than 4.5 to 1.0. At December 31, 2002, we were in compliance with the covenants contained in the credit facility and could have borrowed the full $225.0 million available under the credit facility.

8.75% notes

On July 3, 2002, we and Plains E&P Company, our wholly owned subsidiary that has no material assets and was formed for the sole purpose of being a corporate co-issuer of certain notes, issued $200.0 million principal amount of 8.75% notes at an issue price of 98.376%. The 8.75% notes are our unsecured general obligations, are subordinated in right of payment to all of our existing and future senior indebtedness and are jointly and severally guaranteed on a full, unconditional basis by all of our existing and future domestic restricted subsidiaries. The indenture also limits our ability, as well as the ability of our subsidiaries, among other things, to incur additional indebtedness, make certain investments, make restricted payments, sell assets, enter into agreements containing dividends and other payment restrictions affecting subsidiaries, enter into transactions with affiliates, create liens, merge, consolidate and transfer assets and enter into different lines of business. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase. The indenture governing the 8.75% notes permitted the spin-off and the spin-off did not, in itself, constitute a change of control for purposes of the indenture.

The 8.75% notes are not redeemable until July 1, 2007. On or after that date they are redeemable, at our option, at 104.375% of the principal amount for the twelve-month period ending June 30, 2008, at 102.917% of the principal amount for the twelve-month period ending June 30, 2009, at 101.458% of the principal amount for the twelve-month period ending June 30, 2010 and at 100% of the principal amount thereafter. In each case, accrued interest is payable to the date of redemption.

Other

We also have a note with an outstanding principal balance of $1.0 million at December 31, 2002 that was issued in connection with the purchase of a production payment on certain of our producing properties. The note bears interest at 8%, payable annually, and requires an annual principal payment of $511,000 through 2004.

Aggregate total maturities of long-term debt in the next five years are as follows: 2003—$0.5 million; 2004—$0.5 million; and 2005—$35.8 million.

Note 4—*Related Party Transactions*

Prior to the reorganization, we used a centralized cash management system under which our cash receipts were remitted to Plains Resources and our cash disbursements were funded by Plains Resources. We were charged interest on any amounts, other than income taxes payable, due to Plains Resources at the average effective interest rate of Plains Resources long-term debt. For the years ended December 31, 2002, 2001 and 2000 we were charged $10.7 million, $20.4 million and $19.5 million, respectively, of interest on amounts payable to Plains Resources. Of such amounts, $9.3 million, $17.3 million and $15.7 million was included in interest expense in 2002, 2001 and 2000, respectively, and $1.4 million, $3.1 million and $3.8 million was capitalized in oil and gas properties in 2002, 2001 and 2000, respectively.

To compensate Plains Resources for services rendered under the Services Agreement, we are allocated direct and indirect corporate and administrative costs of Plains Resources. Such costs for the years ended December 31, 2002, 2001 and 2000 totaled $4.4 million, $8.2 million and $3.9 million, respectively. Of such amounts, $3.1 million, $6.1 million and $2.8 million was included in general and administrative expense in 2002, 2001 and 2000, respectively, and $1.3 million, $2.1 million and $1.1 million was capitalized in oil and gas properties in 2002, 2001 and 2000, respectively.

In addition, prior to the reorganization Plains Resources entered into various derivative instruments to reduce our exposure to decreases in the market price of oil. At the time of the reorganization, all open derivative instruments held by Plains Resources on our behalf were assigned to us.

In connection with the reorganization and the spin-off we entered into certain agreements with Plains Resources, 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 the upstream assets and liabilities of Plains Resources, other than its 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 Plains Resources; other provisions governing our relationship with Plains Resources, including mandatory dispute arbitration, sharing information, confidentiality and other covenants; and a noncompetition provision.

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

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

Plains Resources transition services agreement. This agreement became effective as of the date of the spin-off and provides that we will provide Plains Resources tax, accounting, payroll, employee benefits, legal and financial services on an interim basis. We will charge Plains Resources on a monthly basis our costs of providing such services. No charges were made to Plains Resources in 2002 under the terms of this agreement.

Technical services agreement. The technical services agreement provides that we will provide Calumet Florida, a subsidiary of Plains Resources, 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 charge Plains Resources on a monthly basis our costs of providing such services. No charges were made to Plains Resources in 2002 under the terms of this agreement.

We charter private aircraft from Gulf Coast Aviation Inc. ("Gulf Coast"), a corporation which from time-to-time leases an aircraft owned by our Chief Executive Officer. In 2002, we paid Gulf Coast $0.2 million in connection with charter services in which our Chief Executive Officer's aircraft was used. The charter services were arranged through arms-length dealings and the rates were market-based.

Note 5—Benefit Plans

We have adopted a nonqualified retirement plan (the "Plan") for certain of our officers who were formerly officers of Plains Resources. Benefits under the Plan are based on salary at the time of adoption of the Plains Resources plan, vest over the 15-year period designated by the Plains Resources plan and are payable over a 15-year period commencing at age 60. The Plan is unfunded.

The following table summarizes our unfunded pension obligation at December 31, 2002 (in thousands):

Projected benefit obligation for service rendered to date	$ 510
Plan assets at fair value	—
Benefit obligation in excess of fair value of plan assets	(510)
Unrecognized (gain) loss	193
Unrecognized prior service costs	75
Adjustment to recognize minimum liability	(268)
Net amount recognized	$(510)

The weighted-average discount rate used in determining the projected benefit obligation at December 31, 2002 was 6.75%.

We also adopted a 401(k) defined contribution plan whereby we match 100% of an employee's contribution (subject to certain limitations in the plan). Matching contributions are made 100% in cash. The initial contribution under the plan, $0.1 million, was made for the pay period ended December 31, 2002.

Note 6—Stock Compensation Plans

At the time of the spin-off all individuals holding outstanding options to acquire Plains Resources common stock were granted an equal number of stock appreciation rights ("SARs") with respect to our common stock. The exercise price of the SARs was based on the exercise price of the Plains Resources options adjusted for the relationship of the closing price (with dividend) of Plains Resources common stock on the spin-off date ($23.05 per share) less the closing price (on a "when-issued" basis) of our common stock on the spin-off date ($9.10 per share), both as reported on the NYSE, and such closing price of our common stock ($9.10 per share). All recipients of our SARs received the benefit of prior service credit at Plains Resources and have the same amount of vesting as they had under their related Plains Resources stock options and vesting terms remain unchanged. Generally, the SARs have a pro rata vesting period of two to five years and an exercise period of five to ten years.

SARs are subject to variable accounting treatment. Accordingly, at the end of each quarter, we compare the closing price of our common stock on the last day of the quarter to the exercise price of each SAR. To the extent the closing price exceeds the exercise price of each SAR, we recognize such excess as an accounting charge for the SAR's deemed vested at the end of the quarter to the extent such excess had not been recognized in previous quarters. If such excess were to be less than the extent to which accounting charges had been recognized in previous quarters, we would recognize the difference as income in the quarter. We recognized a $2.7 million accounting charge as compensation expense equal to the aggregate in-the-money value of the SARs deemed vested at the spin-off date and an additional $1.0 million accounting charge to reflect the movement in our common stock price and the vesting deemed to have occurred from the spin-off date to December 31, 2002.

The following table reflects the SARs 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	Weighted Number Exercisable at 12/31/02	Weighted Average Exercise Price
$2.46—$8.33	719	1.7 years	$ 5.18	632	$ 5.12
9.08— 9.08	1,000	8.4 years	9.08	—	—
9.10— 9.36	884	4.3 years	9.27	60	9.36
9.37— 9.76	571	3.6 years	9.44	180	9.52
9.97—10.50	873	4.1 years	10.01	619	10.03
2.46—10.50	4,047	4.7 years	8.68	1,491	7.86

Also at the time of the spin-off we granted an award of 165,000 restricted shares of common stock to certain of our officers that vest in three equal annual installments beginning on the first annual anniversary of the date of grant. We will recognize total compensation expense of $1.5 million ratably over the life of the grant.

Note 7—Income Taxes

Until the date of the spin-off, our taxable income or loss was included in the consolidated income tax returns filed by Plains Resources. Income tax obligations reflected in these financial statements with respect to such returns are based on the tax sharing agreement that provides that income taxes are calculated assuming we filed a separate combined income tax return. Currently payable income taxes at December 31, 2001 are included in Payable to Plains Resources Inc. in the consolidated balance sheet at December 31, 2001.

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	December 31, 2001
U.S. Federal		
Deferred tax assets:		
Net operating losses	$ 846	$ —
Alternative minimum tax credit	106	—
Commodity hedging contracts and other	8,572	658
	9,524	658
Deferred tax liabilities:		
Net oil & gas acquisition, exploration and development costs	(48,715)	(36,520)
Commodity hedging contracts and other	—	(10,700)
	(48,715)	(47,220)
Net U.S. Federal deferred tax asset (liability)	(39,191)	(46,562)
States		
Deferred tax liability	(12,225)	(10,631)
Net deferred tax assets (liability)	$(51,416)	$(57,193)

At December 31, 2002, for federal income tax purposes, we had carryforwards of approximately $2.4 million of regular tax net operating losses, and $0.1 million of enhanced oil recovery credits. The NOL carryforwards expire in 2019.

Set forth below is a reconciliation between the income tax provision (benefit) computed at the United States statutory rate on income 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	$15,039	$31,101	$15,935
State income taxes, net of federal benefit	2,409	4,758	2,232
Other	(716)	(1,471)	(1,402)
Income tax expense on income before income taxes and cumulative effect of accounting change	16,732	34,388	16,765
Income tax benefit allocated to cumulative effect of accounting change	—	(1,042)	—
Income tax provision	$16,732	$33,346	$16,765

Under the terms of a tax allocation agreement, we have agreed to indemnify Plains Resources if the spin-off is not tax-free to Plains Resources as a result of various actions taken by us or with respect to our failure to take various actions. In addition, we agreed that, during the three-year period following the spin-off, without the prior written consent of Plains Resources, we will not engage in transactions that could adversely affect the tax treatment of the spin-off unless we obtain a supplemental tax ruling from the IRS or a tax opinion acceptable to Plains Resources 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 Plains Resources to ensure we would be able to comply with our obligation under this agreement. We may not be able to control some of the events that could trigger this indemnification obligation.

Note 8—Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

Operating leases. We lease certain real property, equipment and operating facilities under various operating leases. Future noncancellable commitments related to these leases total $0.9 million in each of 2003, 2004 and 2005, $0.4 million in 2006, $0.3 million in 2007 and $0.4 million thereafter. Total expenses related to operating lease obligations were less than $0.1 million in each of 2002, 2001 and 2000.

Environmental matters. 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. However, in some instances, we have received an indemnity in connection with such purchase. There can be no assurance that we will be able to collect on these indemnities. Often these regulations are more burdensome on older properties that were operated before the regulations came into effect such as some of our properties in California and Illinois that have operated for over 90 years. We have established policies for continuing compliance with environmental laws and regulations. We also 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, 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. Typically, when producing oil and gas assets are purchased the purchaser assumes the obligation to plug and abandon wells that are part of such assets. However, in some instances, we received an indemnity with respect to those costs.

We estimate at December 31, 2002 our future costs related to plugging, abandonment and remediation (including our commitments related to the purchase of certain of our onshore California properties) will be approximately $0.8 million, net of salvage and other considerations including the fair value of fee lands on which we conduct certain of our production operations ($104.9 million before salvage value and other considerations). Effective January 1, 2003, upon adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations", we will record the fair value of liabilities associated with our asset retirement obligations. See Note 1—Recent Accounting Pronouncements.

In connection with the purchase of certain of our onshore California properties, each year we are required to plug and abandon 20% of the then remaining inactive wells (there were 154 inactive wells at December 31, 2002). If we do not meet this commitment, and the requirement is not waived, we must escrow funds to cover the cost of the wells that were not abandoned. To date we have not been required to escrow any funds. In addition, until the end of 2005, we are required to spend at least $600,000 per year (and $300,000 per year from 2006 through 2010) to remediate oil contaminated soil from existing well sites that require remediation.

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. 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.

In the ordinary course of business, we are a claimant and/or defendant in various other legal proceedings. In particular, we are required to indemnify Plains Resources for any liabilities it incurs in connection with a lawsuit it (through a predecessor interest in Stocker Resources, Inc.) has regarding an electric services contract with Commonwealth Energy Corporation. In this lawsuit, Plains Resources is seeking a declaratory judgment that it was entitled to terminate the contract and that Commonwealth has no basis for proceeding against a related $1.5 million performance bond. In a counter suit against Plains Resources, Commonwealth is seeking unspecified damages. We understand that Plains Resources intends to defend its rights vigorously in this matter. 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, oil spills, 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. Our operations in California, including transportation of oil by pipelines within the city and county of Los Angeles, are especially susceptible to damage from earthquakes and involve increased risks of personal injury, property damage and marketing interruptions because of the population density of southern California. 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. We maintain coverage for earthquake damages in California but this coverage may not provide for the full effect of damages that could occur and we may be subject to additional liabilities. 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.

Industry Concentration

Financial instruments which potentially subject us to concentrations of credit risk consist principally of accounts receivable with respect to our oil and gas operations and derivative instruments related to our hedging activities. Plains All American Pipeline, L.P. ("PAA"), in which Plains Resources held a 25% interest at December 31, 2002, 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.

The contract counterparties for our derivative commodity contracts are all major financial institutions with Standard & Poor's ratings of A or better. Three of the financial institutions are participating lenders in the credit facility, with one such counterparty holding contracts that represent approximately 33% of the fair value of all of our open positions at December 31, 2002.

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 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 and gas production which could have a negative impact on future results of operations or cash flows.

Note 9—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 included in other assets and other long-term liabilities are stated at fair value. The carrying amounts and fair values of our other financial instruments are as follows (in thousands):

	December 31, 2002	
	Carrying Amount	Fair Value
Long-Term Debt		
Bank debt	$ 35,800	$ 35,800
Senior subordinated debt	196,855	208,000
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 10—Oil and natural gas activities

Costs incurred

Our oil and natural 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			
Unproved properties	$ 65	$ 44	$ 73
Proved properties(1)	(4,516)	1,645	1,953
Exploration costs	602	286	293
Exploitation and development costs(2)	68,346	123,778	68,186
	$64,497	$125,753	$70,505

(1) In connection with the acquisition of an additional interest in the Point Arguello field, offshore California, we assumed certain obligations of the seller. As consideration for receiving the transferred properties and assuming such obligations, we received $2.4 million. In addition, we received $2.7 million as our share of revenues less costs for the period April 1 to July 31, 2002, the period prior to ownership.

(2) Includes capitalized general and administrative expense of $6.0 million, $6.2 million and $5.2 million in 2002, 2001 and 2000, respectively, and capitalized interest expense of $2.4 million, $3.1 million and $3.8 million in 2002, 2001 and 2000, respectively.

PLAINS EXPLORATION & PRODUCTION COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

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	$ 629,454	$ 561,034
Accumulated DD&A	(167,278)	(139,797)
	$ 462,176	$ 421,237

The average DD&A rate per equivalent unit of production was $3.17, $2.70 and $2.25 in 2002, 2001 and 2000, 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	$24,612	$27,523	$31,090
Exploration costs	—	—	425
Capitalized interest	5,433	5,848	3,222
	$30,045	$33,371	$34,737

Unproved property costs not subject to amortization consist primarily of acquisition costs related to unproved areas and capitalized interest. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves established or impairment determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as the undeveloped areas are tested. Our onshore properties and one offshore property consist of mature but underdeveloped oil properties that were acquired from major or large independent oil and gas companies. These fields were discovered from 1906 to 1981, have produced significant volumes since initial discovery, and exhibit complex reservoir and geologic conditions. Due to the nature of the reserves, the ultimate evaluation of the properties will occur over a period of several years. We expect that 70% of the costs not subject to amortization at December 31, 2002 will be transferred to the amortization base over the next three years and the remainder within the next ten years. The leases covering the properties are held by production and will not limit the time period for evaluation. Approximately 10%, 9% and 11% of the balance in unproved properties at December 31, 2002, related to additions made in 2002, 2001 and 2000, 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 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	$188,563	$204,139	$142,451
Production costs	(78,451)	(63,795)	(56,228)
Depreciation, depletion and amortization	(29,632)	(23,707)	(18,395)
Income tax expense	(31,307)	(45,022)	(24,981)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 49,173	$ 71,615	$ 42,847

Supplemental reserve information (unaudited)

The following information summarizes our net proved reserves of oil (including condensate and natural 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., and Ryder Scott Company in 2002 and 2001 and H.J. Gruy and Associates, Inc., Netherland, Sewell & Associates, Inc., and Ryder Scott Company in 2000. The estimates are in accordance with SEC regulations.

Management believes 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 and gas 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. Almost all of our reserve base (approximately 95% of year-end 2002 reserve volumes) is comprised of oil properties that are sensitive to oil price volatility.

Estimated quantities of oil and natural gas 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 (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved Reserves						
Beginning balance	223,293	96,217	204,387	93,486	195,213	90,873
Revision of previous estimates	8,897	(19,827)	(13,093)	(5,485)	(5,601)	(3,597)
Extensions, discoveries, improved recovery and other additions	15,049	6,661	40,218	11,571	22,429	9,252
Purchase of reserves in-place	2,635	—	—	—	—	—
Sale of reserves in-place	(930)	(2,535)	—	—	—	—
Production	(8,783)	(3,362)	(8,219)	(3,355)	(7,654)	(3,042)
Ending balance	240,161	77,154	223,293	96,217	204,387	93,486
Proved Developed Reserves						
Beginning balance	119,248	59,101	105,679	52,184	100,758	49,255
Ending balance	127,415	53,317	119,248	59,101	105,679	52,184

Standardized measure of discounted future net cash flows (unaudited)

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

	December 31,		
	2002	2001	2000
Future cash inflows	$ 6,819,645	$ 3,662,137	$ 5,850,215
Future development costs	(431,841)	(305,261)	(249,319)
Future production expense	(2,528,065)	(1,714,132)	(2,748,492)
Future income tax expense	(1,446,528)	(537,252)	(1,030,400)
Future net cash flows	2,413,211	1,105,492	1,822,004
Discounted at 10% per year	(1,529,704)	(721,025)	(1,032,566)
Standardized measure of discounted future net cash flows	$ 883,507	$ 384,467	$ 789,438

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 and gas 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 2. Such arrangements are not reflected in the reserve reports. The overall average year-end prices used in the reserve reports as of December 31, 2002, 2001 and 2000 were $26.91, $15.31 and $21.93 per barrel of oil, respectively, and $4.63, $2.56 and $14.63 per Mcf of gas, respectively.

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 $1.5 billion, $0.6 billion and $1.3 billion 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 and gas 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	$ 384,467	$ 789,438	$ 727,286
Sales, net of production expenses	(125,463)	(139,545)	(159,035)
Net change in sales and transfer prices, net of production expenses	979,042	(665,006)	180,935
Changes in estimated future development costs	(62,801)	(17,535)	(16,097)
Extensions, discoveries and improved recovery, net of costs	98,969	89,010	141,641
Previously estimated development costs incurred during the year	39,692	86,881	27,855
Purchase of reserves in-place	16,583	—	—
Sale of reserves in-place	(2,959)	—	—
Revision of quantity estimates and timing of estimated production	(133,618)	(156,362)	(82,141)
Accretion of discount	62,376	141,598	101,667
Net change in income taxes	(372,781)	255,988	(132,673)
Balance, end of year	$ 883,507	$ 384,467	$ 789,438

Note 11—Quarterly Financial Data (Unaudited)

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	$40,673	$45,140	$50,907	$51,843	$188,563
Operating profit	16,753	20,471	21,408	21,121	79,753
Net income	5,864	8,218	7,418	4,737	26,237
Basic and diluted earnings per share	$ 0.24	$ 0.34	$ 0.30	$ 0.20	$ 1.08
2001					
Revenues	$53,773	$56,924	$50,598	$42,844	$204,139
Operating profit	35,039	34,202	27,060	19,938	116,239
Income before cumulative effect of accounting change	17,573	17,080	12,468	7,572	54,693
Cumulative effect of accounting change	(1,522)	—	—	—	(1,522)
Net income	16,051	17,080	12,468	7,572	53,171
Basic and diluted earnings per share					
Income before cumulative effect of accounting change	$ 0.73	$ 0.71	$ 0.51	$ 0.31	2.26
Cumulative effect of accounting change	(0.06)	—	—	—	(0.06)
Net income	0.67	0.71	0.51	0.31	2.20

Note 12—Consolidating Financial Statements

We and Plains E&P Company are the co-issuers of the 8.75% notes discussed in Note 3. The 8.75% notes are jointly and severally guaranteed on a full and unconditional basis by Arguello Inc., Plains Illinois Inc. and certain immaterial subsidiaries (referred to as "Guarantor Subsidiaries").

The following financial information presents consolidating financial statements, which include:

- PXP (the "Issuer");
- the guarantor subsidiaries on a combined basis ("Guarantor Subsidiaries");
- elimination entries necessary to consolidate the Issuer and Guarantor Subsidiaries; and
- the company on a consolidated basis.

Plains E&P Company has no material assets or operations; accordingly, Plains E&P Company has been omitted from the Issuer financial information.

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2002
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current Assets				
Cash and cash equivalents	$ 1,004	$ 24	$ —	$ 1,028
Accounts receivable and other current assets	21,273	8,646	—	29,919
Commodity hedging contracts	2,594	—	—	2,594
Inventories	4,009	1,189	—	5,198
	28,880	9,859	—	38,739
Property and Equipment, at cost				
Oil and gas properties—full cost method				
Subject to amortization	507,501	121,953	—	629,454
Not subject to amortization	17,621	12,424	—	30,045
Other property and equipment	2,008	199	—	2,207
	527,130	134,576	—	661,706
Less allowance for depreciation, depletion and amortization	(75,007)	(93,487)	—	(168,494)
	452,123	41,089	—	493,212
Investment in and Advances to Subsidiaries	33,243	—	(33,243)	—
Other Assets	19,221	(292)	—	18,929
	$533,467	$ 50,656	$(33,243)	$ 550,880
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and other current liabilities	$ 50,996	$ 10,096	$ —	$ 61,092
Commodity hedging contracts	15,188	9,384	—	24,572
Current maturities on long-term debt	511	—	—	511
	66,695	19,480	—	86,175
Long-Term Debt	233,166	—	—	233,166
Other Long-Term Liabilities	4,101	2,202	—	6,303
Payable to Parent	—	58,948	(58,948)	—
Deferred Income Taxes	55,685	(4,269)	—	51,416
Stockholders' Equity				
Stockholders' equity	186,678	(20,009)	20,009	186,678
Accumulated other comprehensive income	(12,858)	(5,696)	5,696	(12,858)
	173,820	(25,705)	25,705	173,820
	$533,467	$ 50,656	$(33,243)	$ 550,880

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2001
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current Assets				
Cash and cash equivalents	$ 11	$ 2	$ —	$ 13
Accounts receivable and other current assets	10,703	5,679	—	16,382
Commodity hedging contracts	13,872	7,915	—	21,787
Inventories	3,252	1,377	—	4,629
	27,838	14,973	—	42,811
Property and Equipment, at cost				
Oil and gas properties—full cost method				
Subject to amortization	450,038	110,996	—	561,034
Not subject to amortization	19,676	13,695	—	33,371
Other property and equipment	1,322	194	—	1,516
	471,036	124,885	—	595,921
Less allowance for depreciation, depletion and amortization	(56,137)	(84,667)	—	(140,804)
	414,899	40,218	—	455,117
Investment in and Advances to Subsidiaries	(21,496)	—	21,496	—
Other Assets	16,275	2,552	—	18,827
	$437,516	$ 57,743	$21,496	$ 516,755
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current Liabilities				
Accounts payable and other current liabilities	$ 29,822	$ 11,546	$ —	$ 41,368
Current maturities on long-term debt	511	—	—	511
	30,333	11,546	—	41,879
Payable to Plains Resources Inc.	172,603	62,558	—	235,161
Long-Term Debt	1,022	—	—	1,022
Other Long-Term Liabilities	—	1,413	—	1,413
Deferred Income Taxes	53,471	3,722	—	57,193
Stockholders' equity				
Combined owner's equity	164,203	(25,889)	25,889	164,203
Accumulated other comprehensive income	15,884	4,393	(4,393)	15,884
	180,087	(21,496)	21,496	180,087
	$437,516	$ 57,743	$21,496	$ 516,755

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2002
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and liquids	$123,795	$54,243	$ —	$178,038
Gas	10,299	—	—	10,299
Other operating revenues	—	226	—	226
	134,094	54,469	—	188,563
Costs and Expenses				
Production expenses	50,510	27,941	—	78,451
General and administrative	13,479	1,707	—	15,186
Depreciation, depletion and amortization	21,532	8,827	—	30,359
	85,521	38,475	—	123,996
Income from Operations	48,573	15,994	—	64,567
Other Income (Expense)				
Equity in earnings of subsidiaries	5,988	—	(5,988)	—
Expenses of terminated public equity offering	(2,395)	—		(2,395)
Interest expense	(12,942)	(6,435)	—	(19,377)
Interest and other income	(140)	314	—	174
Income Before Income Taxes and Cumulative Effect of Accounting Change	39,084	9,873	(5,988)	42,969
Income tax expense				
Current	(1,232)	(5,121)	—	(6,353)
Deferred	(11,615)	1,236	—	(10,379)
Net Income	$ 26,237	$ 5,988	$(5,988)	$ 26,237

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2001
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and liquids	$124,250	$50,645	$ —	$174,895
Gas	28,771	—	—	28,771
Other operating revenues	—	473	—	473
	153,021	51,118	—	204,139
Costs and Expenses				
Production expenses	41,458	22,337	—	63,795
General and administrative	8,708	1,502	—	10,210
Depreciation, depletion and amortization	18,413	5,692	—	24,105
	68,579	29,531	—	98,110
Income from Operations	84,442	21,587	—	106,029
Other Income (Expense)				
Equity in earnings of subsidiaries	11,528	—	(11,528)	—
Interest expense	(10,679)	(6,732)	—	(17,411)
Interest and other income	94	369	—	463
Income Before Income Taxes and Cumulative Effect of Accounting Change	85,385	15,224	(11,528)	89,081
Income tax expense				
Current	(2,832)	(3,182)	—	(6,014)
Deferred	(27,620)	(754)	—	(28,374)
Income Before Cumulative Effect of Accounting Change	54,933	11,288	(11,528)	54,693
Cumulative effect of accounting change, net of tax benefit	(1,762)	240	—	(1,522)
Net Income	$ 53,171	$11,528	$(11,528)	$ 53,171

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2000
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and liquids	$ 85,921	$40,513	$ —	$126,434
Gas	16,017	—	—	16,017
	101,938	40,513	—	142,451
Costs and Expenses				
Production expenses	35,278	20,950	—	56,228
General and administrative	5,168	1,140	—	6,308
Depreciation, depletion and amortization	15,450	3,409	—	18,859
	55,896	25,499	—	81,395
Income from Operations	46,042	15,014	—	61,056
Other Income (Expense)				
Equity in earnings of subsidiaries	6,859	—	(6,859)	—
Interest expense	(10,212)	(5,673)	—	(15,885)
Interest and other income	213	130	—	343
Income Before Income Taxes	42,902	9,471	(6,859)	45,514
Income tax expense				
Current	(168)	(2,263)	—	(2,431)
Deferred	(13,985)	(349)	—	(14,334)
Net Income	$ 28,749	$ 6,859	$(6,859)	$ 28,749

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2002
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 26,237	$ 5,988	$(5,988)	$ 26,237
Items not affecting cash flows from operating activities:				
Depreciation, depletion and amortization	21,532	8,827	—	30,359
Equity in earnings of subsidiaries	(5,988)	—	5,988	—
Deferred income taxes	11,615	(1,236)	—	10,379
Other noncash items	457	—	—	457
Change in assets and liabilities from operating activities:				
Accounts receivable and other assets	(12,301)	337	—	(11,964)
Inventories	(757)	181	—	(576)
Accounts payable to Plains Resources Inc.	4,946	—	—	4,946
Accounts payable and other liabilities	20,217	(1,229)	—	18,988
Net cash provided by operating activities	65,958	12,868	—	78,826
CASH FLOWS FROM INVESTING ACTIVITIES				
Acquisition, exploration and developments costs	(54,811)	(9,686)	—	(64,497)
Additions to other property and equipment	(185)	(5)	—	(190)
Proceeds from property sales	529	—	—	529
Net cash used in investing activities	(54,467)	(9,691)	—	(64,158)
CASH FLOWS FROM FINANCING ACTIVITIES				
Principal payments of long-term debt	(511)	—	—	(511)
Change in revolving credit facility	35,800	—	—	35,800
Proceeds from debt issuance	196,752	—	—	196,752
Debt issuance costs	(5,936)	—	—	(5,936)
Contribution from Plains Resources Inc.	52,200	—	—	52,200
Distribution to Plains Resources Inc.	(311,964)	—	—	(311,964)
Receipts from (payments to) Plains Resources Inc.	23,518	(3,155)	—	20,363
Other	(357)	—	—	(357)
Net cash provided by (used in) financing activities	(10,498)	(3,155)	—	(13,653)
Net increase (decrease) in cash and cash equivalents	993	22	—	1,015
Cash and cash equivalents, beginning of year	11	2	—	13
Cash and cash equivalents, end of year	$ 1,004	$ 24	$ —	$ 1,028

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2001
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 53,171	$ 11,528	$(11,528)	$ 53,171
Items not affecting cash flows from operating activities:				
Depreciation, depletion and amortization	18,413	5,692	—	24,105
Equity in earnings of subsidiaries	(11,528)	—	11,528	—
Deferred income taxes	27,620	754	—	28,374
Cumulative effect of adoption of accounting change	1,762	(240)	—	1,522
Change in derivative fair value	(7)	1,062	—	1,055
Other noncash items	263	733	—	996
Change in assets and liabilities from operating activities:				
Accounts receivable and other assets	9,449	(252)	—	9,197
Inventories	(586)	(5)	—	(591)
Accounts payable and other liabilities	157	(1,178)	—	(1,021)
Net cash provided by operating activities	98,714	18,094	—	116,808
CASH FLOWS FROM INVESTING ACTIVITIES				
Acquisition, exploration and developments costs	(108,577)	(17,176)	—	(125,753)
Additions to other property and equipment	(127)	—	—	(127)
Net cash used in investing activities	(108,704)	(17,176)	—	(125,880)
CASH FLOWS FROM FINANCING ACTIVITIES				
Principal payments of long-term debt	(511)	—	—	(511)
Receipts from (payments to) Plains Resources Inc.	10,272	(1,212)	—	9,060
Net cash provided by (used in) financing activities	9,761	(1,212)	—	8,549
Net increase (decrease) in cash and cash equivalents	(229)	(294)	—	(523)
Cash and cash equivalents, beginning of year	240	296	—	536
Cash and cash equivalents, end of year	$ 11	$ 2	$ —	$ 13

PLAINS EXPLORATION & PRODUCTION COMPANY
CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2000
(in thousands)

	Issuer	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income	$ 28,749	$ 6,859	$(6,859)	$ 28,749
Items not affecting cash flows from operating activities:				
Depreciation, depletion and amortization	15,450	3,409	—	18,859
Equity in earnings of subsidiaries	(6,859)	—	6,859	—
Deferred income taxes	13,985	349	—	14,334
Other noncash items	—	—	—	—
Change in assets and liabilities from operating activities:				
Accounts receivable and other assets	7,192	405	—	7,597
Inventories	228	(423)	—	(195)
Accounts payable and other liabilities	9,745	375	—	10,120
Net cash provided by operating activities	68,490	10,974	—	79,464
CASH FLOWS FROM INVESTING ACTIVITIES				
Acquisition, exploration and developments costs	(54,782)	(15,723)	—	(70,505)
Additions to other property and equipment	(359)	(7)	—	(366)
Net cash used in investing activities	(55,141)	(15,730)	—	(70,871)
CASH FLOWS FROM FINANCING ACTIVITIES				
Principal payments of long-term debt	(511)	—	—	(511)
Receipts from (payments to) Plains Resources Inc.	(12,803)	182	—	(12,621)
Net cash provided by (used in) financing activities	(13,314)	182	—	(13,132)
Net increase (decrease) in cash and cash equivalents	35	(4,574)	—	(4,539)
Cash and cash equivalents, beginning of year	205	4,870	—	5,075
Cash and cash equivalents, end of year	$ 240	$ 296	$ —	$ 536

Note 13—Subsequent Event

On February 3, 2003 we announced that we entered into a definitive agreement pursuant to which we will acquire 3TEC Energy Corporation, or 3TEC, for approximately $333 million plus the assumption of debt, which totaled $99.0 million at December 31, 2002. Under the terms of the merger agreement, 3TEC common stockholders will receive $8.50 of cash and 0.85 of a share of our common stock for each share of 3TEC common stock they own, which equates to a total of $16.97 per 3TEC common share based on the January 31, 2003 closing price of $9.96 per share for our common stock. This exchange ratio is subject to an upward or downward adjustment should the market price of our common stock fall below $7.65 per share or rise above $12.35 per share, respectively. This mechanism is intended to provide that the total value of the consideration received by 3TEC common stockholders at the effective time of the merger will be between $15.00 and $19.00 per share of 3TEC common stock. For this purpose, the market price of our common stock will be the average closing price of our common stock for the 20 consecutive trading days immediately preceding the third trading day prior to closing. In addition, if the market price of our common stock is less than $6.25, we may either (i) terminate the merger agreement or (ii) in lieu of issuing more common stock increase the cash consideration paid per share of 3TEC common stock by the amount our common stock market price is less than $6.25 times the exchange ratio after adjustment.

The merger is expected to qualify as a tax free reorganization under Section 368(a) of the Internal Revenue Code. Accordingly, the merger is expected to be tax free to our stockholders and tax free for the stock portion of the consideration received by 3TEC stockholders. We anticipate funding the cash portion of the merger through a new credit facility.

The Boards of Directors of both companies have approved the merger agreement and each has recommended it to their respective stockholders for approval. The transaction is subject to stockholder approval from both companies and other customary conditions. Assuming the market price of our common stock is between $7.65 and $12.35, after the merger is completed, 3TEC common stockholders will own approximately 40% of the combined company and our stockholders will own approximately 60% of the combined company.

CORPORATE INFORMATION

DIRECTORS

James C. Flores
Chairman and Chief Executive Officer
Plains Exploration & Production Company

Alan R. Buckwalter, III
Retired, Chairman & CEO
Chase Bank of Texas

Jerry L. Dees
Retired, Senior Vice President
Exploration and Land
Vastar Resources, Inc.

Tom H. Delimitros
General Partner
AMT Venture Funds

John H. Lollar
Managing Partner
Newgulf Exploration, LP

OFFICERS

James C. Flores
Chairman and Chief Executive Officer

John T. Raymond
President and Chief Operating Officer

Stephen A. Thorington
Executive Vice President and
Chief Financial Officer

Timothy T. Stephens
Executive Vice President, Secretary and
General Counsel

Cynthia A. Feeback
Senior Vice President—Accounting and Treasurer

Thomas M. Gladney
Senior Vice President—Operations

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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CORPORATE HEADQUARTERS

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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 Resources;
- the consequences of our officers and employees providing services to both us and Plains Resources and not being required to spend any specified percentage or amount of time on our business;
- 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 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;
- 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.

Designed by Curran & Connors, Inc. / www.curran-connors.com

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