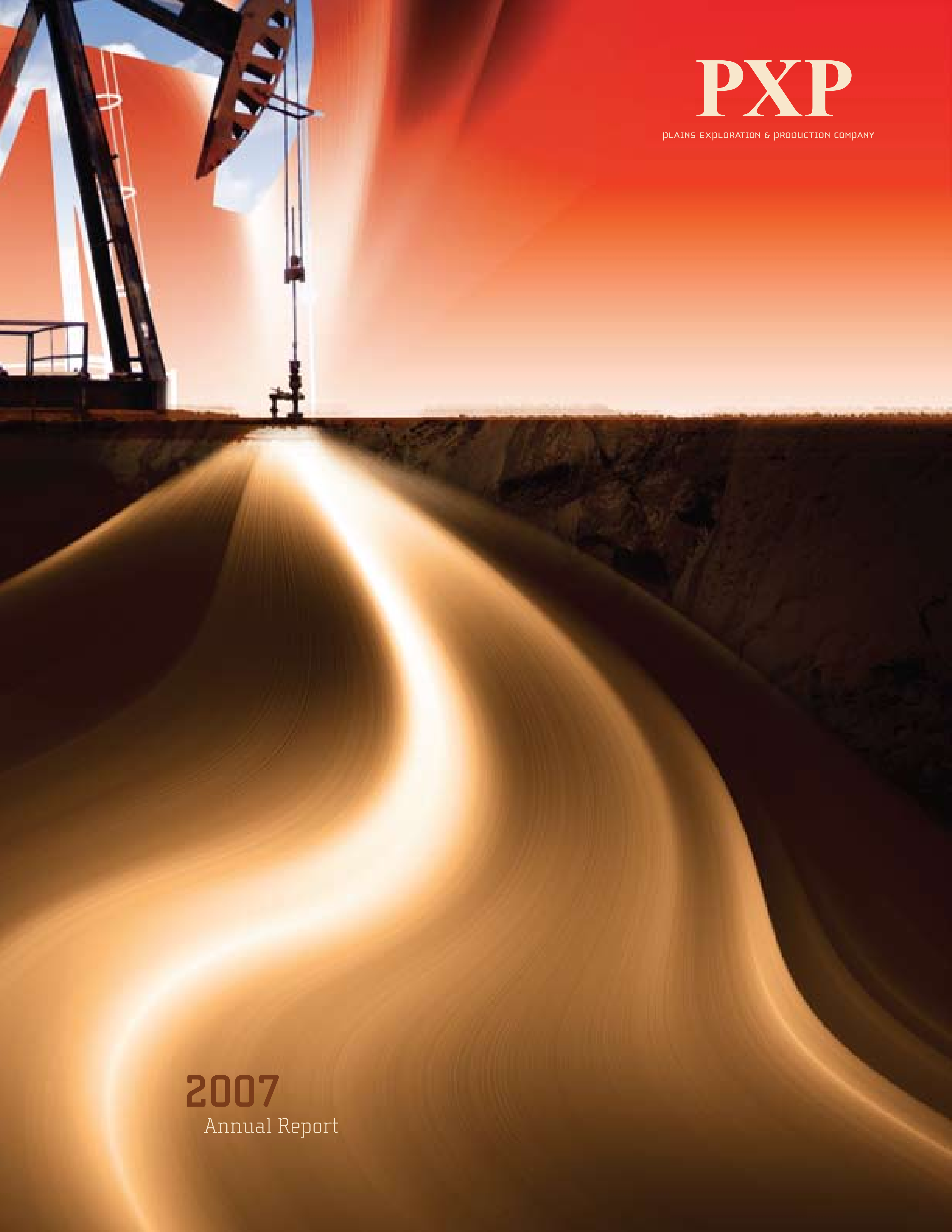


PXP

PLAINS EXPLORATION & PRODUCTION COMPANY

2007 Annual Report

our company

We are an independent oil and gas company engaged in the activities of acquiring, developing, exploring and producing oil and gas properties primarily in the United States. We own oil and gas properties with principal operations in:

- the Los Angeles and San Joaquin Basins onshore California;
- the Santa Maria Basin offshore California;
- the Piceance and Wind River Basins in the Rocky Mountains;
- the Permian Basin in West Texas and New Mexico;
- the Anadarko Basin in the Texas Panhandle; and
- the South Texas and Gulf Coast regions, including the Gulf of Mexico.

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. In addition to the assets in our principal focus areas listed above, we also have interests in exploration prospects offshore New Zealand and Vietnam.

Financial Highlights

(in thousands, except per share and percentage information)

	2007[1]	2006	2005	2004[2]	2003[3]
Reserve Data:					
Total oil reserves (barrels)	**436,533**	333,217	356,333	351,403	227,728
Total gas reserves (Mcf)	**1,519,976**	110,922	267,921	407,400	319,177
Total barrels of oil equivalent (BOE)	**689,862**	351,704	400,987	419,303	280,924
Percentage proved developed volume	**51%**	52%	67%	68%	58%
Estimated future net cash flows	**$ 18,042,121**	$ 5,652,412	$ 6,772,811	$ 4,651,720	$ 3,040,267
Standardized measure	**$ 7,623,323**	$ 2,510,663	$ 3,082,166	$ 2,236,719	$ 1,256,803
Percentage proved developed present value	**67%**	68%	77%	79%	71%
Operating Data:					
Oil production (barrels)	**18,124**	18,975	18,671	16,441	9,267
Average oil price (per barrel)[4]	**$ 61.60**	$ 55.62	$ 46.76	$ 36.12	$ 26.92
Gas production (Mcf)	**29,312**	20,629	29,359	38,590	18,195
Average gas price (per Mcf)[4]	**$ 5.68**	$ 6.73	$ 7.15	$ 5.90	$ 5.01
BOE production	**23,010**	22,413	23,564	22,872	12,300
Average BOE price[4]	**$ 56.12**	$ 53.76	$ 45.96	$ 35.92	$ 27.69
Production expense per BOE	**$ 18.25**	$ 14.49	$ 12.10	$ 9.76	$ 8.52
Selected Financial Data:					
Total revenue	**$ 1,272,840**	$ 1,018,503	$ 944,420	$ 671,706	$ 304,090
Income from Operations	**$ 419,634**	$ 1,348,450	$ 343,700	$ 208,599	$ 103,629
Income (loss) before cumulative effect of accounting change	**$ 158,751**	$ 599,710	$ (214,012)	$ 8,840	$ 47,087
Cumulative effect of accounting change, net of income tax	**-**	$ (2,182)	-	-	$ 12,324
Net income (loss)	**$ 158,751**	$ 597,528	$ (214,012)	$ 8,840	$ 59,411
Income (loss) per share					
Before cumulative effect of accounting change	**$ 1.99**	$ 7.67	$ (2.75)	$ 0.14	$ 1.41
Cumulative effect of accounting change	**-**	$ (0.03)	-	-	$ 0.37
Net income (loss)	**$ 1.99**	$ 7.64	$ (2.75)	$ 0.14	$ 1.78
Weighted average shares outstanding					
Basic	**78,627**	77,273	77,726	63,542	33,321
Diluted	**79,808**	78,234	77,726	64,014	33,469
Total assets	**$ 9,693,351**	$ 2,463,228	$ 2,741,942	$ 2,633,245	$ 1,212,268
Long-term debt	**$ 3,305,000**	$ 235,500	$ 797,375	$ 635,468	$ 487,906
Total shareholders' equity	**$ 3,338,247**	$ 1,130,683	$ 718,337	$ 870,375	$ 354,256

(1) Reflects the acquisition of Pogo Producing Company effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.

(2) Reflects the acquisition of Nuevo Energy Company effective May 14, 2004.

(3) Reflects the acquisition of 3TEC Energy Corporation effective June 1, 2003.

(4) Average realized sales price before derivative transactions.

fellow shareholders

2007 was the most active year in PXP's five-year history.

We continued our strategy of acquiring oil and gas properties or companies with meaningful current production and cash flow as well as large development project inventories and dynamic growth opportunities. Our goal is not only to be opportunistic from a valuation point of view but also to build a company that creates per share value for the shareholder in the form of organic growth and share repurchases. We closed two major acquisitions, announced two significant asset divestitures, announced major discoveries in the Gulf of Mexico and delivered strong daily production rates from our base business.

The enhanced asset base now includes significant positions in high-quality basins located in California, the Rocky Mountains, Texas, New Mexico and the Gulf of Mexico. These changes have positioned us to capitalize on strong but volatile energy prices, to improve our cash margin per barrel of oil equivalent, and to generate a growing stream of income and cash flow. This enables PXP to have the financial flexibility to opportunistically pursue strategic acquisitions and to buy our own common stock, each of which creates more value per share over time.

Our commitment to a long-term strategy of accelerating per-share growth is intact and is now supported by a substantial portfolio of cash generating and growth assets, as well as an extraordinary group of employees dedicated to achieving results. We continue to optimize the value of our long-lived properties and efficiently increase reserves and production while pursuing other value-enhancing, growth opportunities. For the fifth consecutive year of positive, double-digit returns, our stock price ended the year at $54 per share—the highest year-end stock price in the Company's history.

strategic transactions

Always cognizant of market conditions, asset net present values, operating efficiencies and costs, we regularly scrutinize the market for opportunities to capture value on existing PXP assets and add assets with considerable value.

We identified and executed two remarkable opportunities, adding substantial asset value, growth potential and cash-flow generating capability. In May PXP acquired a sizable development business in the Piceance Basin of Colorado for $1 billion and in November acquired Pogo Producing Company (Pogo) for $3.6 billion. The synergies of combining Pogo and PXP resulted in significant annual cost savings. Then, through post-acquisition divestitures and partnering, we high-graded and aligned operator strengths to maximize operating efficiencies and investment returns.

Late in the year we announced divestitures in the amount of $1.75 billion for 50% of our interests in the Piceance and Permian Basins and all of our interests in the San Juan Basin. The after-tax values realized through these transactions are significantly higher than the properties were valued in our stock price. We identified and leveraged the dislocation between the equity and asset markets to realize some very attractive values for the PXP shareholders. The transactions closed during the first quarter 2008 and the after-tax proceeds are planned for share repurchases, debt reduction and reinvestment in our business.

These efforts resulted in a balanced, geographically diverse, lower-risk and efficient portfolio of producing properties capable of growing production and reserves over time, complemented by an attractive portfolio of other longer term value-enhancing projects.

operational performance

We entered the year focused on developing our large California oil resource base and exploring a significant number of Gulf of Mexico prospects. In addition to accomplishing these goals through the execution of an active development and exploration program, we successfully added and integrated the Piceance Basin and Pogo properties. Also, our employee and contractor safety incident rates improved over 2006.

PXP ended the year with fourth quarter sales volumes of approximately 85.1 thousand barrels of oil equivalent (BOE) per day, a 58% increase compared to the fourth quarter of 2006, and proved reserves of 689.9 million BOE, a 96% increase over 2006 year-end reserves. Post divestment, PXP's proved reserves will be approximately 577 million BOE, of which 69% is oil and 31% is natural gas.

exploration

Our exploration investment in the Gulf of Mexico once again yielded material discoveries, Flatrock and Vicksburg. The Flatrock discovery well found significant accumulations of gas/condensate pay in multiple intervals. A total of five wells, all productive, were drilled in 2007 and early 2008 in the Flatrock area of South Marsh Island Block 212. Production from the Flatrock area began in January 2008. The Vicksburg discovery well in 7,500 feet of water in DeSoto Canyon blocks 353 and 397 and Mississippi Canyon block 393 was announced in January 2008. PXP expects to participate in an additional similar offset prospect with the same operator during 2008.

Continuing to build on the 2006 and 2007 Gulf of Mexico exploration successes, PXP's 2008 plans include participation in additional Flatrock area wells, delineation drilling of the Friesian discovery well announced in November 2006 and select deepwater Gulf of Mexico exploration prospects.

PXP 12.31.07 STOCK PRICE $54.00
12.31.02 STOCK PRICE $9.75

- **2007** Pogo Producing, **acquired**
- **2007** Piceance Basin properties, **acquired**
- **2006** Gulf of Mexico discoveries, **sold**
- **2006** Non-core California and West Texas properties, **sold**
- **2005** East Texas properties, **sold**
- **2004** Nuevo Energy, **acquired**
- **2003** 3TEC Energy, **acquired**
- **2002** PXP became public company and started trading on NYSE December 2002

Development

Development activity in each of the California asset areas remained high in 2007. These properties, which include over 2,500 potential drilling locations, continue to produce solid economic returns, provide reserve additions and generate substantial cash flow per share.

In May we acquired Piceance Basin properties, which include approximately 60,000 acres and associated midstream assets. Since the acquisition, we increased production from these assets 57% by maintaining an active drilling program and completing facility expansion projects. The Pogo properties, acquired late in the year, show promise for sustainable multi-year development drilling, especially in the Permian Basin, the Texas Panhandle and the South Texas areas.

Financial performance

PXP's net income for 2007 was $159 million, or $1.99 per diluted share, on revenues of $1.3 billion, compared to net income of $598 million, or $7.64 per diluted share, on revenues of $1.0 billion for 2006. The 2006 results include a $983 million pre-tax gain on the sale of oil and gas properties and a $298 million pre-tax derivative mark-to-market loss. Net cash provided by operating activities during the year was $588 million compared to $675 million in 2006.

We ended the year with $3.3 billion in long-term debt and a debt-to-capitalization ratio of 50% before $1.75 billion of asset sale proceeds received in early 2008. As in 2006, we ended 2007 with a strong balance sheet and the financial flexibility to repurchase PXP common shares and to seek investment opportunities with long-term benefits for PXP shareholders.

Looking Forward

Our $1.15 billion 2008 capital budget supports PXP's diversified growth strategy by funding drilling programs in each of its key asset areas. Approximately 65% of this spending is planned for production and development activities in the California, Rockies, Permian Basin, Texas Panhandle, South Texas and Gulf of Mexico asset areas, while approximately 25% is intended for exploration projects primarily in the Gulf of Mexico, onshore Gulf Coast and the Texas Panhandle. The balance is allocated to capitalized interest, general and administrative costs, and California real estate development.

Our accomplishments achieved through 2007 were notable. With an enhanced asset base and financial flexibility, PXP is well positioned to accelerate per share value in 2008. We look forward to carefully investing excess cash to create shareholder value. In particular, we are pleased our Board authorized up to $1 billion of stock repurchases supplementing the 2006 and 2007 stock repurchase program in which we purchased 7.7 million shares for $342 million. We believe allocating excess cash to repurchase PXP stock is a sound investment that benefits our shareholders as we continue to grow the value of our assets.

On behalf of the Board of Directors and the employees of PXP, I want to thank all of our shareholders and partners for your continued confidence and support.

JAMES C. FLORES
Chairman, President and
Chief Executive Officer

NYSE corporate governance compliance

As required by the rules of the New York Stock Exchange, following our 2007 Annual Meeting of Shareholders we submitted the annual CEO Certification regarding NYSE corporate governance listing standards to the NYSE. In addition, we have filed the certifications required by Section 302 of the Sarbanes-Oxley Act of 2002 with our 2007 Annual Report on Form 10-K as Exhibits 31.1 and 31.2.

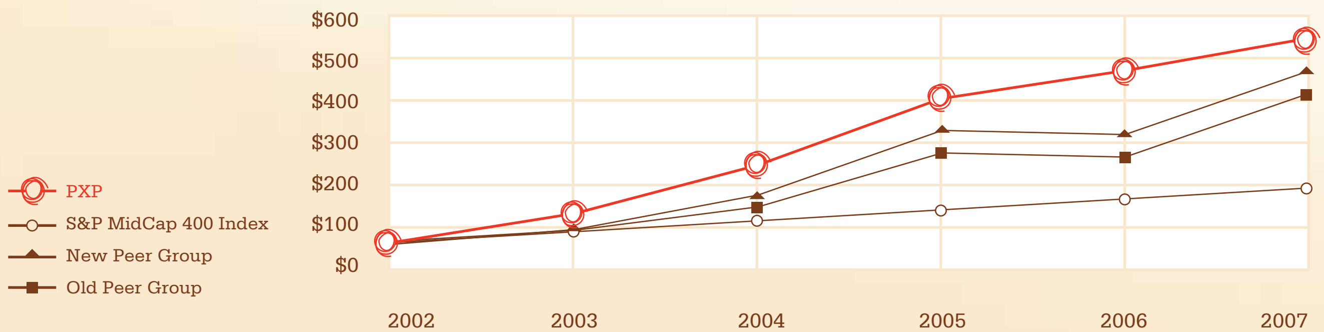
comparison of shareholder return

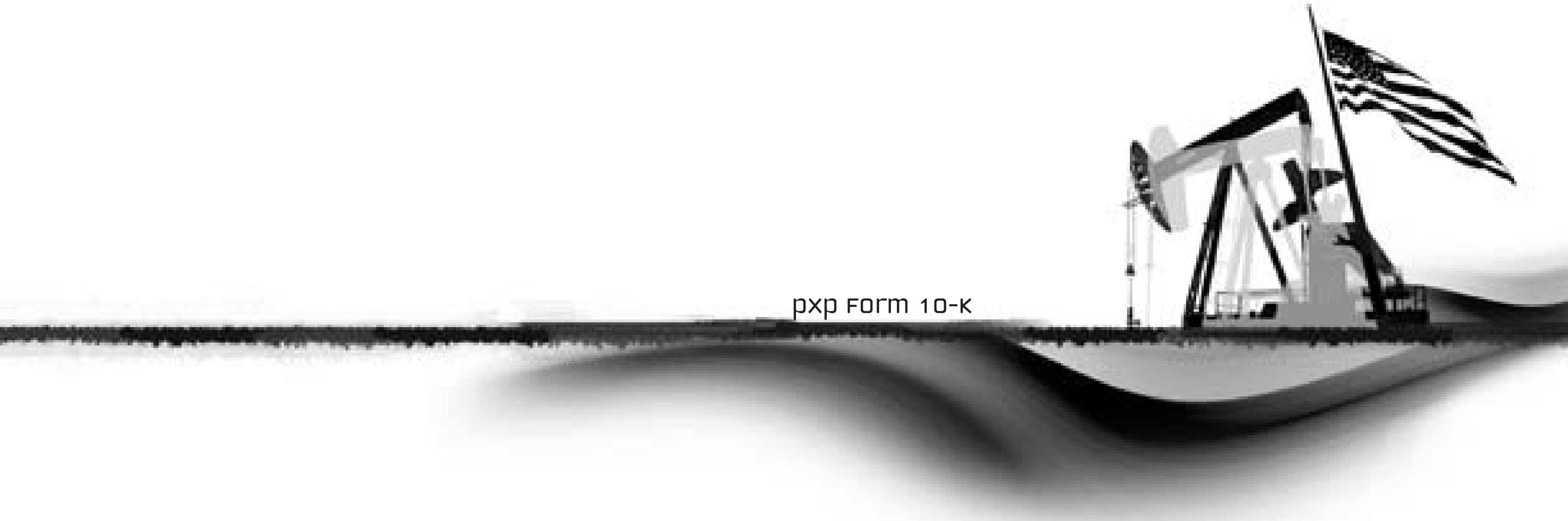
The following graph compares the cumulative total shareholder return on our common stock with the cumulative return of (i) the S&P Mid-cap 400, (ii) a peer group consisting of Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Co., Denbury Resources Inc., EOG Resources, Inc., Forest Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Range Resources Corporation, Ultra Petroleum Corp. and XTO Energy Inc. and (iii) a peer group used by PXP last year consisting of Chesapeake Energy Corporation, Cimarex Energy Co., Denbury Resources Inc., EOG Resources, Inc., Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, Pogo Producing Company and XTO Energy Inc..

The graph covers the period from December 31, 2002, through December 31, 2007, and assumes that $100 was invested on December 31, 2002 and that any dividends were reinvested. No dividends have been declared or paid on PXP's common stock. Shareholder returns over the period indicated should not be considered indicative of future shareholder returns.

The information contained in the Performance Graph shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that PXP specifically incorporates it by reference into such filing.

comparison of cumulative five year total return





pxp Form 10-K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2007

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	**33-0430755**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

700 Milam Street, Suite 3100
Houston, Texas 77002
(Address of principal executive offices)
(Zip Code)

(713) 579-6000
(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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer,” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

On January 31, 2008, there were 112.8 million 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 $3.4 billion on June 29, 2007 (based on $47.81 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange on such date).

DOCUMENTS INCORPORATED BY REFERENCE: The information required in Part III of the Annual Report on Form 10-K is incorporated by reference to the registrant's definitive proxy statement to be filed pursuant to Regulation 14A for the registrant's 2008 Annual Meeting of Stockholders.

PLAINS EXPLORATION & PRODUCTION COMPANY
2007 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 information regarding Plains Exploration & Production Company that is intended to be covered by the safe harbor for “forward-looking statements” provided by the Private Securities Litigation Reform Act of 1995. 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. Although we believe that our expectations are based on reasonable assumptions, there are risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- uncertainties inherent in the development and production of oil and gas and in estimating reserves;
- unexpected difficulties in integrating our operations as a result of any significant acquisitions;
- unexpected future capital expenditures (including the amount and nature thereof);
- impact of oil and gas price fluctuations, including the impact on our reserve volumes and values and our earnings as a result of our derivative positions;
- 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 success of our derivative activities;
- the success of our risk management activities;
- the effects of competition;
- the availability (or lack thereof) of acquisition or combination opportunities;
- the availability (or lack thereof) of capital to fund our business strategy and/or operations;
- 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 reliance on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report and our other filings with the Securities and Exchange Commission. 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 for any obligation to disclose material information under the federal securities laws, we do not intend to update these forward-looking statements and information. See Item 1A "Risk Factors” and Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results” in this report for additional discussions of risks and uncertainties.

AVAILABLE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC’s Public Reference Room at

100 F Street, NE, Room 1580 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 website at *www.sec.gov*. No information from the SEC's website is incorporated by reference herein. Our website is *www.PXP.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 website. These documents are posted to our website as soon as reasonably practicable after we have filed or furnished these documents with the SEC. We have placed on our website copies of our Corporate Governance Guidelines, charters of our Audit, Organization & Compensation and Nominating & Corporate Governance Committees, and our Policy Concerning Corporate Ethics and Conflicts of Interest. We intend to post amendments to and waivers of our Policy Concerning Corporate Ethics and Conflicts of Interest (to the extent applicable to our principal executive officer, our principal financial officer and our principal accounting officer) at this location on our website. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, Plains Exploration & Production Company, 700 Milam, Suite 3100, Houston, TX 77002. No information from our website is incorporated by reference herein.

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 document:

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.

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

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.

Gas. Natural gas.

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

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of gas.

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 by one degree Fahrenheit.

MMcf. One million cubic feet of gas.

Oil. Crude oil, condensate and natural gas liquids.

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

Proved reserves. Proved oil and gas reserves are the estimated quantities of oil, 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) oil, 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) oil, gas, and natural gas liquids, that may occur in undrilled prospects; and (iv) oil, gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

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

Reserve additions. Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery and other additions and purchases of reserves in-place.

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 volumes.

Royalty interest. 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.

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

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.

The terms “development well”, "exploratory well", “proved developed reserves”, “proved reserves” and “proved undeveloped reserves” are defined by the SEC. References herein to “PXP”, the "Company", "we", "us" and "our" mean Plains Exploration & Production Company.

PART I

Items 1 and 2. *Business And Properties*

General

We are an independent oil and gas company primarily engaged in the activities of acquiring, developing, exploring and producing oil and gas properties primarily in the United States. We own oil and gas properties with principal operations in:

- the Los Angeles and San Joaquin Basins onshore California;
- the Santa Maria Basin offshore California;
- the Piceance and Wind River Basins in the Rocky Mountains;
- the Permian Basin in West Texas and New Mexico;
- the Anadarko Basin in the Texas Panhandle; and
- the South Texas and Gulf Coast regions, including the Gulf of Mexico.

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. In addition to the assets in our principal focus areas listed above, we also have interests in exploration prospects offshore New Zealand and Vietnam. We use derivative contracts to manage our exposure to commodity price risk.

Oil and Gas Reserves

As of December 31, 2007, we had estimated proved reserves of 689.9 MMBOE, of which 63% was comprised of oil and 51% was proved developed. We have a total proved reserve life of approximately 18 years and a proved developed reserve life of approximately 9 years. We believe our long-lived, low production decline reserve base combined with our active risk management program should provide us with relatively stable and recurring cash flow. As of December 31, 2007, and based on year-end 2007 reference prices as adjusted for area and quality differentials, our reserves had a standardized measure of $7.6 billion. Our pro forma proved reserves were 577.1 MMBOE after adjusting for the $1.75 billion asset divestments that have or are expected to close in the first quarter of 2008. See “Divestments.”

The following table sets forth certain information with respect to our reserves that for 2007 are based upon (1) reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott Company L.P. and (2) reserve volumes prepared by us and audited by Ryder Scott and Miller and Lents, Ltd. For 2007, the independent petroleum consulting firms prepared 80% of the reserve volumes, we prepared 19% of the reserve volumes, which the independent petroleum consulting firms audited, and we prepared 1% of the reserve volumes, which were not audited by an independent petroleum consulting firm. In 2006 and 2005, 100% of our reserves were based on reserve reports prepared by Netherland, Sewell & Associates, Inc. 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 December 31,		
	2007	2006	2005
	(dollars in thousands)		
Oil and Gas Reserves			
Oil (MBbls)			
Proved developed	227,915	171,646	234,638
Proved undeveloped	208,618	161,571	121,695
	436,533	333,217	356,333
Gas (MMcf)			
Proved developed	757,736	62,021	193,904
Proved undeveloped	762,240	48,901	74,017
	1,519,976	110,922	267,921
MBOE	689,862	351,704	400,987
Standardized Measure	$7,623,323(1)	$2,510,663	$3,082,166
Average year-end realized prices (2)			
Oil and liquids (per Bbl)	$ 85.50	$ 50.71	$ 51.24
Gas (per Mcf)	$ 6.28	$ 6.14	$ 8.02
Year-end NYMEX prices			
Oil and liquids (per Bbl)	$ 95.98	$ 61.05	$ 61.04
Gas (per Mcf)	$ 7.48	$ 6.30	$ 11.23
Reserve life (years) (3)	18.0	17.3	17.3

(1) Our year-end 2007 standardized measure includes future development costs related to proved undeveloped reserves of $481 million in 2008, $595 million in 2009 and $589 million in 2010.

(2) Based on prices in effect at year-end with adjustments based on location and quality. The market price for California crude oil and natural gas in the Rocky Mountains differs from the established market indices due primarily to transportation and refining costs and transportation constraints.

(3) Reserve life is calculated by dividing proved reserve volumes at year-end by production volumes. Production volumes are based on annualized fourth quarter production and are adjusted, if necessary, to reflect property acquisitions and dispositions.

During the three-year period ended December 31, 2007, we participated in 76 exploratory wells, of which 54 were successful, and 625 development wells, 615 of which were successful. During this period, we incurred aggregate oil and gas acquisition, development and exploration costs of $7.8 billion, approximately 89% of which was for acquisition and development activities. During this period, proved reserve additions totaled 409 MMBOE. Reserve additions and the number of wells drilled do not include any amounts attributable to the two deepwater Gulf of Mexico discoveries that were sold to Statoil Gulf of Mexico LLC in November 2006 prior to the wells being completed and any related reserve additions being recognized. Costs include expenditures related to these discoveries. See “Divestments.” Approximately 51% of our reserves at December 31, 2007 are classified as proved developed compared to 52% at December 31, 2006.

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 standardized measure 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 derivatives 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.

Since December 31, 2006, we have not filed any estimates of total net proved oil or gas reserves with any federal authority or agency other than the SEC.

Acquisitions

We 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 that meet our investment criteria.

In November 2007, we acquired Pogo Producing Company for approximately 40 million shares of common stock and approximately $1.5 billion in cash. Pogo was engaged in oil and gas exploration, development, acquisition and production activities on its properties primarily located in the onshore United States, Vietnam and New Zealand. We accounted for the transaction under purchase accounting rules effective November 6, 2007.

In May 2007, we acquired certain properties in the Piceance Basin from a private company for $975 million in cash and one million shares of common stock. The Piceance Basin properties include interests in oil and gas producing properties in the Mesaverde geologic section of the Piceance Basin in Colorado, plus associated midstream assets, including a 25% interest in Collbran Valley Gas Gathering, LLC (“CVGG”).

In April 2005 and September 2005, we acquired certain California producing oil and gas properties, primarily located in the Los Angeles and the Santa Maria Basins in two separate transactions for a total of $134 million.

Divestments

On December 14, 2007, together with certain of our subsidiaries, we entered into a definitive purchase and sale agreement with a subsidiary of Occidental Petroleum Corporation (“Oxy”) to sell

50% of our interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, the Piceance Basin in Colorado (including a 50% interest in the entity that holds our interest in CVGG) and the Utah Overthrust exploratory prospect to Oxy for $1.55 billion in cash. We will retain 50% of our working interest in the Permian and Piceance Basin properties. The transaction effective date is January 1, 2008 and is expected to close during the first quarter of 2008 subject to customary closing conditions and adjustments.

On December 14, 2007, certain of our subsidiaries entered into a definitive purchase and sale agreement with XTO Energy Inc. to sell our oil and gas interests located in the San Juan Basin in New Mexico and in the Barnett Shale in Texas. The sale of the San Juan Basin and Barnett Shale properties closed on February 15, 2008, with an effective date of January 1, 2008, and we received $199 million of cash. We are scheduled to purchase XTO's 50% working interest in the Big Mac prospect area located on the Texas Gulf Coast for approximately $20 million during the first quarter of 2008. Subsequent to closing the transaction, we will have a 100% working interest in the Big Mac prospect area, covering approximately 50,000 net lease acres.

Proved reserves attributed to the asset divestments expected to close in the first quarter of 2008 were 112.8 MMBOE at December 31, 2007.

In November 2006, we closed the sale of non-producing oil and gas properties to Statoil. We sold Statoil our working interests in two deepwater Gulf of Mexico discoveries, Big Foot and Caesar, and one deepwater exploration prospect, Big Foot North. We received approximately $706 million in cash proceeds.

In September 2006, we closed the sale of non-strategic oil and gas properties located primarily in California and Texas to subsidiaries of Oxy for net proceeds of approximately $864 million.

In May 2005, we closed the sale to XTO of interests in producing properties located in East Texas and Oklahoma for net proceeds of approximately $341 million.

Development and Exploration

We expect to continue our reserve and production growth through the development of our existing inventory of projects in each of our primary operating areas. To complement the development activities, we expect to continue to expand on our success in exploratory drilling by taking advantage of our exploratory projects in the Gulf of Mexico, onshore Gulf Coast and Panhandle area of Texas. To implement the plans, we will focus on:

- allocating investment capital prudently after rigorous evaluation;
- optimizing production practices;
- realigning and expanding injection processes;
- performing stimulations, recompletions, artificial lift upgrades and other operating margin and reserve enhancements;
- focusing geophysical and geological talent;
- employing modern seismic applications;
- establishing land and prospect inventory practices to reduce costs; and
- using new technology applications in drilling and completion practices.

By implementing our development and exploration 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, 2007, our additions to proved reserves, excluding reserves added as a result of acquisition activities, totaled 152 MMBOE. During this period we incurred aggregate oil and gas development and exploration costs of $1.8 billion.

Our Board of Directors has approved a $1.15 billion 2008 capital budget with approximately 65% to be utilized for production and development activities in the California, Rocky Mountains, Texas and Gulf of Mexico asset areas. Approximately 25% is intended for exploration projects primarily in the Gulf of Mexico, onshore Gulf Coast and Panhandle area of Texas. The remaining 10% is intended for estimated capitalized general and administrative and interest expense, other property and equipment and California real estate development.

Of our 2008 development spending, approximately 30% is allocated to the California oil fields located in the Los Angeles, the San Joaquin and the Santa Maria Basins. The Rocky Mountains, which includes the Piceance Basin and the Madden Field, represents approximately 15% while Texas, which primarily includes the Texas Panhandle properties, the Permian Basin and the South Texas asset areas, represents approximately 25%. The remaining development budget is allocated to the delineation of our significant 2007 Gulf of Mexico exploratory discoveries, Flatrock and Friesian.

Description of Properties

Our oil and gas operations are concentrated in the Los Angeles and San Joaquin Basins onshore California, the Santa Maria Basin offshore California, the Piceance and Wind River Basins in the Rocky Mountains, the Permian Basin in West Texas and New Mexico, the Anadarko Basin in the Texas Panhandle and the South Texas and Gulf Coast regions, including the Gulf of Mexico. We also have interests in exploration prospects offshore New Zealand and Vietnam. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential.

We continue to increase the value of our oil and gas assets through a diversified growth strategy with sustained development of our base properties in the California, Rocky Mountains, Texas and Gulf of Mexico asset areas and continued exploration primarily in the Gulf of Mexico, onshore Gulf Coast and the Panhandle area of Texas. Capital additions to our oil and gas properties were $823 million in 2007, excluding acquisitions, and are currently budgeted to be approximately $1.1 billion in 2008.

The following table sets forth information with respect to our oil and gas properties as of and for the year ended December 31, 2007:

	Proved Reserves at December, 31, 2007		
	Proved Developed	**Proved Undeveloped**	**Total Proved**
		(MMBOE)	
Onshore California	156.6	185.8	342.4
Offshore California	25.8	1.0	26.8
Rocky Mountains	58.8	81.4	140.2
Permian Basin	71.8	39.5	111.3
Texas Panhandle	8.9	16.1	25.0
South Texas	21.8	3.4	25.2
Gulf Coast Basin, including Gulf of Mexico	5.3	8.2	13.5
All other areas	5.2	0.3	5.5
Total	354.2	335.7	689.9

Onshore California

Los Angeles Basin

We hold a 100% working interest in the majority of our Los Angeles Basin properties, including Inglewood, Las Cienegas, Montebello, Packard, and San Vicente. The LA Basin properties are characterized by light crude (18 to 29 degree API gravity), well depths ranging from 2,000 feet to over 10,000 feet and include both primary production and waterfloods.

In 2007, we spent $73 million on capital projects in the LA Basin and drilled 40 wells, including injection wells. Drilling was concentrated on waterflood projects in the Inglewood Field Vickers Rindge formation with 12 wells drilled and 10 wells in the Moynier and Rubel formations. In addition, we drilled 10 wells at Montebello and 8 wells at Las Cienegas. Our net average daily sales volume from our LA Basin properties in the fourth quarter of 2007 was 13.1 MBOE per day. In 2008, a similar development drilling program is planned.

San Joaquin Basin

Our San Joaquin Basin properties are primarily in the Cymric, Midway Sunset and South Belridge Fields. These are long-lived fields that have heavier oil (12 to 16 degree API gravity), and shallow wells (generally less than 2,000 feet) that require enhanced oil recovery techniques, including steam injection.

We spent $93 million in 2007 on capital projects in the San Joaquin Basin and drilled 118 wells, including injection wells. Drilling was concentrated in the Midway Sunset Field, where we spent $62 million and drilled 81 wells, and in the Cymric Field, where we spent $23 million and drilled 28 wells. At Midway Sunset our development and expansion program in 2007 included 45 Diatomite, 18 Marvic Spellacy, 12 Marvic, 4 Potter and 2 A-1 wells and accompanying facility expansion. In the Cymric Field we drilled 16 Diatomite and 12 Tulare wells. Our net average daily sales volume from our San Joaquin Basin properties in the fourth quarter of 2007 was 20.8 MBOE per day. Our continuous development and expansion program in 2008 includes drilling Diatomite, Marvic Spellacy and Potter wells at the Midway Sunset Field, Diatomite and Tulare wells in the Cymric Field and Tulare wells in the South Belridge Field.

Other Onshore California

We hold a 100% working interest (94% net revenue interest) in the Arroyo Grande Field located in San Luis Obispo County, California. This is a long-lived field that has heavier oil (12 to 16 degree API gravity), wells depths averaging 1,700 feet and requires continuous steam injection. In 2007, we spent $15 million on capital projects in this field and drilled 40 wells, including injection wells. Our net average daily sales volume from the Arroyo Grande Field in the fourth quarter of 2007 was 1.4 MBOE per day. We plan to continue our drilling efforts within the Arroyo Grande Field in 2008 to increase the efficiency of the recovery process.

Santa Maria Basin Offshore California

Point Arguello. We hold a 69.3% working interest (58% net revenue interest) in the Point Arguello Unit and the various partnerships owning the related transportation, processing and marketing infrastructure. Capital projects in 2007 totaled $5 million and our net average daily sales volume in the fourth quarter of 2007 was 4.6 MBOE per day. Much of the activity on this property has and will continue to concentrate on maintaining production through well workovers and recompletions.

Point Pedernales. We hold a 100% working interest (83% net revenue interest) in the Pt. Pedernales Field which includes one platform, utilized to exploit the Federal OCS Monterey Reservoir by extended reach directional wells, and support facilities which lie within the onshore Lompoc Field. In 2007 we spent $15 million on capital projects in this field. Our combined net average daily sales volume from our Pt. Pedernales and Lompoc Fields averaged 7.7 MBOE per day in the fourth quarter of 2007. Much of the activity on this property has and will continue to concentrate on maintaining production through well workovers and recompletions. In addition, we are actively pursuing obtaining leases from the California State Lands Commission for the Tranquillon Ridge Field located in state waters adjacent to the Point Pedernales Field where it can be drilled from our existing platform.

Rocky Mountains

Piceance Basin

Our working interest is generally 100% in the Piceance Basin, which covers over 64,000 gross (60,000 net) acres, includes over 200 producing wells and over 3,000 additional potential drilling locations in the Mesaverde geologic section plus the associated midstream assets, including a 25% interest in CVGG. The Mesaverde geologic section is found at depths generally ranging from 6,000 feet to 10,000 feet below the surface.

In 2007, we spent $126 million on capital projects in the Piceance Basin utilizing five rigs and drilling 61 wells. Stage one of a planned expansion project of the Anderson Gulch Processing Plant on the Collbran Valley Gathering System ("CVGS") was completed in late August 2007 and stage two was completed in early October 2007. Drilling was concentrated in the East Plateau, Brush Creek and Hell's Gulch Fields. Our net average daily sales volume from our Piceance Basin properties in the fourth quarter of 2007 was 8.2 MBOE per day. In 2008, we plan to continue our production and reserve development in the Brush Creek, Hell's Gulch and East Plateau fields.

In December 2007, we entered into a definitive purchase and sale agreement with a subsidiary of Oxy to sell 50% of PXP's interests in our oil and gas properties located in the Piceance Basin and a 50% interest in the entity that holds our interest in CVGG. We will retain 50% of our interest in the oil and gas properties and will remain the operator. See "Divestments."

Wind River Basin

We own a non-controlling interest in the Madden Unit located in central Wyoming. The Madden Unit is a federal unit operated by a third party and consists of approximately 64,104 gross acres in the Wind River Basin. PXP owns an average working interest of approximately 14%.

The Madden Unit is characterized by gas production from multiple stratigraphic horizons of the Lower Fort Union, Lance, Mesaverde and Cody sands and the Madison Dolomite. Production from the Madden Unit is typically found at depths ranging from 5,500 to 25,000 feet. Some of the gas produced from the Madden Unit requires processing at the Lost Cabin Gas Plant. PXP owns an approximate 14% interest in the Lost Cabin Gas Plant.

In 2007, subsequent to our acquisition of Pogo, we spent $0.7 million on capital projects in the Madden Unit. Our net average daily sales volume from the acquisition date to year end 2007 was 4.3 MBOE per day. We will continue to target, among other objectives, the Lower Fort Union Sands and the shallower (3,500 feet) Shotgun Sands in 2008.

In late November 2007, the combustion blower for Train III failed at the Lost Cabin Gas Plant and subsequently Train III, which processes nearly half of PXP's net share of gas from the Madden unit, was shut-in. Repairs are currently underway and production is expected to return to pre-shut-in rates during the first quarter of 2008.

San Juan Basin

Our net average daily sales volume from the acquisition date to year end 2007 was 3.0 MBOE per day. In December 2007, we announced a definitive purchase and sale agreement with XTO to sell PXP's interests in the San Juan Basin properties and in the Barnett Shale in Texas. The transaction effective date is January 1, 2008, and it closed on February 15, 2008. See "Divestments."

Permian Basin

We have interests in oil and gas properties on 385,443 gross leasehold acres located in the Permian Basin in West Texas and Southeastern New Mexico.

We entered into a definitive purchase and sale agreement in December 2007 with a subsidiary of Oxy to sell 50% of our interests in oil and gas properties located in the Permian Basin and will retain 50% of our interests in these properties. Oxy will be the operator of all the assets currently operated by PXP. See "Divestments."

Our net average daily sales volume from our Permian Basin properties from the acquisition date to year end 2007 was 18.3 MBOE per day.

We expect to continue development drilling in various known fields and prospects. Drilling objectives for these wells range in vertical depth from 4,500 feet to 17,000 feet below the surface and target numerous formations including, among others, the Grayburg, Delaware (Bell Canyon, Cherry Canyon, Brushy Canyon), Spraberry, Bone Spring, Wolfcamp, Granite Wash, Strawn, Atoka, Morrow and Mississippian formations.

Texas Panhandle

We have interests in oil and gas properties on approximately 495,171 gross leasehold acres with 715 square miles of 3-D seismic located in the Anadarko Basin in the Panhandle of Texas.

Development activities are concentrated in the Turkey Track Ranch and the Courson Ranch areas located primarily in Roberts and Hutchinson Counties as well as in the Wheeler and Marvin Lake Prospects in Wheeler and Hemphill Counties. The structural and stratigraphic objectives include Cleveland Sands, Mississippian carbonates, Granite and Atoka Wash, found at varying depths.

Exploration opportunities in the Panhandle have been identified on a concentration of ranches principally located in Roberts and Hutchinson Counties. Structural objectives include the Hunton Limestone and Dolomite, the Simpson Sandstones and Dolomite and the Ellenburger Dolomite. Stratigraphic traps include the Pennsylvania Granite Wash, Morrow Channel Sands and Mississippian carbonate mounds.

We spent $13.8 million on exploration and development projects in 2007 subsequent to our acquisition of Pogo. Our net average daily sales volume from our Panhandle properties from the acquisition date to year end 2007 was 6.7 MBOE per day. In 2008, we plan to concentrate our development drilling on the Wheeler and Marvin Lake Prospects as well as additional exploration drilling at the Courson and Turkey Track Ranches.

South Texas and Gulf Coast Regions

South Texas

We own interests in oil and gas properties on 41,800 gross acres with 175 square miles of 3-D seismic located in South Texas.

Development activities are primarily for gas reserves concentrated in Los Mogotes, Hundido, South Hundido and Hereford Ranch Fields located in Webb and Zapata Counties. The fields produce from the Eocene Wilcox formation, found at depths generally ranging from 7,000 to 14,000 feet below the surface.

We spent $6.5 million on exploration and development projects in this area in 2007, subsequent to our acquisition of Pogo. Our net average daily sales volume from our South Texas properties from the acquisition date to year end 2007 was 10.4 MBOE per day. In 2008, we plan to continue focusing on development in the Los Mogotes, Hundido, South Hundido and Hereford Ranch Fields.

Gulf Coast Basin

We spent $424 million in 2007 on exploration and development projects in the Gulf Coast Basin, which includes coastal onshore and offshore areas of Texas and Louisiana and the Gulf of Mexico. We participated in a total of 14 exploration wells, five of which were successful and three of which were in progress at year end. Our net average sales volume for the area was 1.9 MBOE per day in the fourth quarter of 2007.

Gulf of Mexico

We entered into an exploration agreement with McMoRan Exploration Co. in November 2006 to participate in several of their Miocene exploratory prospects for $20 million. Through year end 2007, we participated in six wells of which three were successful and two were in progress at year end, all located in the Flatrock area. The discoveries were:

- the Hurricane Deep discovery well on South Marsh Island Block 217 where we own a 30% interest;
- the Flatrock discovery well on South Marsh Island 212 Block where we own a 30% interest; and
- the Cottonwood Point discovery well on Vermillion Block 31 where we own a 40% interest.

Production commenced at Hurricane Deep and Flatrock in the first quarter of 2008

In the deepwater area of the Gulf of Mexico, we participated in three exploration wells, of which two were unsuccessful and the other was in progress at year-end 2007. The Vicksburg discovery well is located on De Soto Canyon Block 353 and was announced in February 2008, in which PXP has a 17.5% working interest. Additional drilling and development plans are subject to further analysis.

On Green Canyon Block 599 we have a 50% interest in the Friesian discovery well announced in November 2006. During 2008, we plan to participate in several development wells and select exploration wells in the Flatrock area and deepwater Gulf of Mexico.

Onshore and Offshore Areas of Texas and Louisiana

Breton Sound. The primarily gas-focused Breton Sound area is located east-southeast of New Orleans. We spent $28.6 million on capital projects and drilled one successful exploratory well in 2007.

Jefferson County, Texas. PXP holds interests in over 92,000 gross acres, including the Oligocene, Hackberry and Vicksburg reservoirs. We own over 275 square miles of new, proprietary 3-D seismic data and interpretation of that data has yielded a number of exploratory prospects. In December 2007 we announced a definitive purchase and sale agreement to acquire XTO's interest. The transaction is expected to close during the first quarter 2008 at which time PXP will have a 100% working interest. We expect exploratory drilling to begin in 2008.

Polk and Tyler Counties, Texas. We hold approximately 69,761 gross acres, including the Cretaceous Woodbine and Austin Chalk Formations. We own approximately 125 square miles of new, proprietary 3-D seismic data and interpretation of that data has yielded a number of exploratory prospects, which are generally 100% owned and operated by PXP.

South Louisiana. We have approximately 51,000 gross acres in central South Louisiana on which to explore for Oligocene and deeper Eocene targets. We own over 165 square miles of new 3-D seismic data in central South Louisiana and hold 100% working interest.

International

New Zealand

We have interests in approximately 930,364 gross acres with 1,885 square kilometers of 3-D seismic in the offshore Northern Taranaki Basin and approximately 5,310,000 gross acres in the offshore East Coast Basin. Prior to the Pogo acquisition, Pogo and its partners drilled one unsuccessful well in the Taranaki Basin during 2007. We anticipate drilling the next prospect in 2009.

Vietnam

Our interest in Block 124 covers approximately 1,480,000 gross acres offshore central Vietnam. We are currently interpreting approximately 850 square kilometers of 3-D seismic data. PXP and its partner, PetroVietnam, expect to drill an exploratory well in late 2008 or 2009.

Other Areas

Wyoming. PXP holds interests in approximately 58,000 gross acres in the Green River Basin. Dependent on when required permits are issued and seasonal limitations, we anticipate initiating drilling in 2009.

North Dakota. We are evaluating our Mississippian Bakken Shale unconventional resource play located in Williams and Dunn Counties. We own a 100% working interest in over 85,000 gross acres.

Utah. PXP owns a 100% working interest in approximately 71,447 gross acres. In December 2007, we announced a definitive purchase and sale agreement with Oxy to sell 50% of PXP's interest in this leasehold.

Southwest Indiana. The Company owns a 50% working interest in a Devonian New Albany Shale unconventional resource play that an industry partner operates. Approximately 237,500 gross acres are under lease. We are evaluating drilling opportunities and development plans.

Texas. PXP owns a 75% working interest in 8,000 gross acres of leasehold in Jack and Wise Counties in the Barnett Shale Trend. In December 2007, we announced a definitive purchase and sale agreement with XTO to sell PXP's interests in these properties. The sale closed on February 15, 2008.

Acquisition, Exploration and Development Expenditures

The following table summarizes the costs incurred during the last three years for our acquisition, exploration and development activities.

	Year Ended December 31,		
	2007	2006	2005
	(In thousands of dollars)		
Property acquisitions costs:			
Unproved properties	$1,822,312	$ 48,315	$ 16,682
Proved properties	3,883,607	7,175	134,696
Exploration costs	465,246	272,352	129,066
Development costs	357,345	319,730	300,439
	$6,528,510	$647,572	$580,883

Development costs include expenditures of $109 million in 2007, $128 million in 2006 and $114 million in 2005 related to the development of proved undeveloped reserves included in our proved oil and gas reserves at the beginning of each year. Development costs also include capital costs required to maintain our proved developed producing reserves.

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 realized and our average production expenses during the years ended December 31, 2007, 2006 and 2005.

	Year Ended December 31,		
	2007	2006	2005
Daily Average Volumes			
Oil and liquids sales (Bbls)	49,655	51,985	51,154
Gas (Mcf)			
Production	80,307	56,519	80,435
Used as fuel	6,307	13,214	14,358
Sales	74,000	43,305	66,077
BOE			
Production	63,041	61,405	64,560
Sales	61,986	59,202	62,166
Unit Economics (in dollars)			
Average NYMEX Prices			
Oil	$ 72.36	$ 66.23	$ 56.61
Gas	6.86	7.21	8.62
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 61.60	$ 55.62	$ 46.76
Gas (per Mcf)	5.68	6.73	7.15
Per BOE	56.12	53.76	45.96
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 9.98	$ 8.32	$ 5.97
Steam gas costs	4.57	2.95	3.32
Electricity	1.76	1.76	1.35
Production and ad valorem taxes	1.44	1.15	1.03
Gathering and transportation	0.50	0.31	0.43
DD&A (oil and gas properties)	12.92	8.96	7.39

See Item 7 “Managements Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations” for cash payments related to our derivatives.

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 are subject to wide fluctuations and depend on numerous factors beyond our control, including location and quality differentials, 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 and volumes of our proved reserves and our revenues, profitability and cash flow.

We use various derivative instruments to manage our exposure to commodity price risks. Derivatives provide us protection on the sales revenue streams if prices decline below the prices at which the derivatives are set. However, ceiling prices in derivatives may result in us receiving less revenue on the volumes than would be received in the absence of the derivatives. Our derivative instruments currently consist of crude oil purchased put option contracts and oil and gas price collar contracts entered into with financial institutions.

A substantial portion of our oil and gas reserves are located in California and approximately 42% of our production is attributable to heavy crude (generally 21 degree API gravity crude oil or lower). The market price for California crude oil differs from the established market indices in the U.S., due principally to the higher transportation and refining costs associated with heavy oil.

Our heavy crude is primarily sold to ConocoPhillips under a 15-year contract which expires on December 31, 2014. This contract provides for pricing based on a percentage of the NYMEX crude oil price for each type of crude oil that we produce and deliver to ConocoPhillips in California. This percentage may be renegotiated every two years, and the current percentage rates were renegotiated at the end of 2007. During 2007, we received approximately 83% of the NYMEX index price for crude oil sold under the ConocoPhillips contract, representing approximately 37% of our total crude oil production. Effective January 1, 2008, we will receive approximately 88% of the NYMEX index price for crude oil sold under this contract.

Approximately 24% of our crude oil production is sold through Plains Marketing, L.P. ("PMLP"), which is a subsidiary of Plains All American Pipeline, L.P., with 42% sold under contracts that provide for NYMEX less a fixed price differential (currently averaging NYMEX less $3.62 per barrel) and the remainder sold under contracts that provide for monthly field posted prices. These contracts expire at various times through 2008. The marketing agreement with PMLP provides that PMLP will purchase for resale at market prices certain of our oil production for which PMLP charges a marketing fee.

Prices received for our gas are subject to seasonal variations and other fluctuations. Approximately 50% of our gas production is sold monthly based on industry recognized, published index pricing. The remainder is priced daily on the spot market. Fluctuations between the two pricing mechanisms can significantly impact the overall differential to the Henry Hub. In addition, the market price for our Rocky Mountain gas production differs from the Henry Hub market indices in the U.S., due principally to transportation constraints and transportation costs.

During 2007, 2006 and 2005, sales to ConocoPhillips accounted for 45%, 54% and 44%, respectively, of our total revenues and sales to PMLP accounted for 31%, 41% and 38%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect; however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions.

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.

Productive Wells and Acreage

As of December 31, 2007, we had working interests in 4,615 gross (3,816.5 net) active producing oil wells and 1,979 gross (1,246.1 net) active producing gas wells. The following table sets forth information with respect to our developed and undeveloped acreage as of December 31, 2007:

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Domestic (1)				
California				
Onshore	91,125	65,013	103,705	72,101
Offshore	41,588	34,328	125,330	21,503
Colorado	7,620	7,467	56,440	53,043
Indiana	215,527	102,571	22,040	10,331
Louisiana				
Onshore	13,795	4,812	115,288	110,373
Offshore	9,526	4,888	244,948	84,030
New Mexico	107,638	83,886	126,388	78,185
Texas	361,214	208,723	559,316	433,019
Utah	—	—	71,447	68,591
Wyoming	30,885	3,895	207,310	158,480
Other states	27,971	9,434	228,533	174,416
	906,889	525,017	1,860,745	1,264,072
International (2)				
New Zealand	—	—	6,240,364	5,774,643
Vietnam	—	—	1,480,000	1,480,000
	—	—	7,720,364	7,254,643
	906,889	525,017	9,581,109	8,518,715

(1) Less than 10% of domestic total net undeveloped acres is covered by leases that expire from 2008 through 2010.

(2) In order to retain approximately 5.4 million net undeveloped acres in New Zealand and all of the undeveloped acres in Vietnam, we will be required to drill two wells in New Zealand and two wells in Vietnam during 2009.

Drilling Activities

Information with regard to our drilling activities during the years ended December 31, 2007, 2006 and 2005, is set forth below:

	Year Ended December 31,					
	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Oil	—	—	1.0	1.0	5.0	5.0
Gas	36.0	32.1	6.0	4.7	6.0	2.7
Dry	8.0	4.9	8.0	6.0	6.0	3.1
	44.0	37.0	15.0	11.7	17.0	10.8
Development Wells						
Oil	140.0	139.1	186.0	185.8	217.0	216.4
Gas	37.0	35.0	5.0	4.4	30.0	12.0
Dry	3.0	3.0	4.0	4.0	3.0	3.0
	180.0	177.1	195.0	194.2	250.0	231.4
	224.0	214.1	210.0	205.9	267.0	242.2

At December 31, 2007, there were 5 gross exploratory and 13 gross development wells (3 net exploratory and 5 net development wells) in progress.

Real Estate

We are in the process of pursuing surface development of portions of the following tracts of real property, some of which are used in our oil and gas operations:

Property	Location	Approximate Acreage (Net to Our Interest)
Montebello	Los Angeles County, California	497
Arroyo Grande	San Luis Obispo County, California	1,080
Lompoc	Santa Barbara County, California	3,727

In January 2006, we entered into real estate consulting agreements with Cook Hill Properties, LLC. Under the terms of the agreements, Cook Hill Properties will be responsible for creating a development plan and obtaining all necessary permits for real estate development in an environmentally responsible manner on the surface estates of our properties listed above. Cook Hill Properties is a 15% participant in the venture and can earn an additional incentive on each property.

Our objective relative to the Montebello project is to take advantage of the positioning of this site as a potential significant residential development project in the San Gabriel Valley region of Greater Los Angeles. The project is located in southeastern Los Angeles County 10 miles east of downtown Los Angeles. Our objective in Lompoc and Arroyo Grande is to provide similar sustainable development inventory to California's Central Coast. Our Lompoc property is located midway between Santa Barbara and San Luis Obispo a few miles inland from the Pacific Ocean; our Arroyo Grande property is located in the geographically desirable region near Pismo Beach and the Edna Valley.

We are actively pursuing the entitlement process for our Montebello and Lompoc properties and are engaged in pre-entitlement activities in Arroyo Grande. Our current development plans include master planned communities with a range of housing from entry level to executive and estate homes, parks and recreational land uses.

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. In 2007, we spent approximately $11 million on our real estate projects.

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 prospects and resources in the oil and gas industry.

Regulation

Our operations are subject to extensive governmental regulation. Many federal, state and local legislative and regulatory bodies' agencies are authorized 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 laws 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 laws and 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, or OSHA, and comparable state and local statutes and rules 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 and local statutes and rules require that we maintain certain information about hazardous conditions or materials used or produced in our operations and that we provide this information to our employees, 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 conditions or substances.

MMS. The United States Minerals Management Service, or 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 exploration, drilling, development and production plans in federal waters. Additionally, the MMS has promulgated regulations requiring offshore production facilities to meet stringent engineering, construction, and environmental specifications, including regulations 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." The MMS has adopted regulations providing for enforcement actions, including civil penalties, and lease forfeiture or cancellation for failure to comply with approved plans for 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 (or other actions taken by the MMS under its regulatory authority) could adversely affect our operations.

We acquired the now-dormant Nuevo Energy Company in May 2004. The United States Attorney's Office has notified Nuevo that it is investigating allegations that during 2000-2002, prior to the acquisition, an unaffiliated contract operator retained by Nuevo may have falsified certain records in violation of federal laws related to equipment testing. We are cooperating with this investigation. Under certain laws, Nuevo may be held responsible for the actions of its agents. However, we do not believe that such investigation will have a material adverse effect on the Company.

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 and other oil and gas 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 may limit the amount of oil and gas we can produce from our wells and 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 and CVGG 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. FERC regulates interstate gas pipeline transportation rates and service conditions. Although FERC does not regulate the production of gas, the agency’s actions are intended to foster increased competition within all phases of the gas industry. To date, 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.

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 increasingly stringent 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. Such statutes include, but are not limited to, the Comprehensive Environmental Response, Compensation and Liability Act, Resource Conservation and Recovery Act, Clean Air Act, Clean Water Act, and Safe Drinking Water Act. Statutes that specifically provide protection to animal and plant species and which may apply to our operations include, but are not limited to, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Endangered Species 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 promulgated there under 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.

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, or is otherwise liable under, 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 incur substantial expense, including remediation costs and other liability under applicable laws and regulations, as well as 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 laws and 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 numerous jurisdictions to operate crude oil, natural gas and related pipelines and equipment that run within the boundaries of these governmental jurisdictions. The permits required for various aspects of our operations are subject to revocation, modification and renewal by issuing authorities.

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 well bores, remove tanks, production equipment and flow lines and restore the well site. 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 receive an indemnity with respect to those costs.

Although we obtained environmental studies on our properties in California and we believe that such properties have been operated in accordance with standard oil and gas industry practices in effect at the time, certain of those properties 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 the purchase agreement. We believe that we do not have any material obligations for operations conducted prior to our acquisition of these properties, other than our obligation to plug existing wells and those normally associated with customary oil and gas 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, and there can be no assurance that any portion of such amounts will be recoverable under the indemnity.

We estimate our 2008 cash expenditures related to plugging, abandonment and remediation will be approximately $11.3 million. Due to the long life of our onshore California reserve base we do not expect our cash outlays for such expenditures for these properties will increase significantly in the next several years. At the Point Arguello Unit, offshore California, the companies from which we purchased our interests retained responsibility for the majority of the 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 are responsible for our 69.3% share of other abandonment costs which primarily consist of wellbore abandonments, conductor removals and site cleanup and preparation.

In connection with the sale of certain properties offshore California in December 2004 we retained the responsibility for certain abandonment costs, including removing, dismantling and disposing of the existing offshore platforms. The present value of such abandonment costs, $42 million ($81 million undiscounted), are included in our asset retirement obligation as reflected on our consolidated balance sheet. In addition, we agreed to guarantee the performance of the purchaser with respect to the remaining abandonment obligations related to the properties (approximately $46 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2007, the escrow account had a balance of $6 million. The fair value of our guarantee, $0.4 million, is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

Employees

As of January 31, 2008, we had 775 full-time employees, two of whom were employed in our international operations and 339 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.

Item 1A. *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 or debt securities.

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 negative impact 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, and other major producing companies;
- political conditions in other oil-producing and gas-producing countries, including the possibility of insurgency or war in such areas;
- the prices of foreign exports and the availability of alternate fuel sources;
- general economic conditions in the United States and worldwide including the value of the U.S. Dollar relative to other major currencies; and
- governmental regulations.

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

- our revenues, cash flows, profitability 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 and our oil and gas reserve volumes.

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 us and independent petroleum engineers. The estimates were calculated using oil and gas prices in effect on the dates 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, transportation 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.

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 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.

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

A substantial portion of our oil and gas reserves are located in California. 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 production is heavier than premium grade light oil and the margin (sales price minus production costs) is generally less than that of lighter oil sales due to the processes required to refine this type of oil and the transportation requirements. As such, the effect of material price decreases will more adversely affect the profitability of heavy oil production compared with lighter grades of oil.

We intend to continue to enter into derivative contracts for a portion of our crude oil and gas production, which exposes us to the risk of financial loss and may result in our making cash payments or prevent us from receiving the full benefit of increases in prices for oil and gas and which may cause volatility in our reported earnings.

We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil and gas prices above the maximum fixed amount specified in the derivative agreement. The derivative instruments also expose us to the risks of financial loss in a variety of circumstances, including when:

- a counterparty to the derivative contract is unable to satisfy its obligations;
- production is delayed or less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy.

For 2008 and 2009, our derivative position consists of purchased put option and oil and gas price collar contracts. The crude oil purchased put options have a strike price of $55.00 on 42,000 barrels per day for 2008 and 32,500 barrels per day for 2009. The only cash settlements we are required to make on these contracts are option premiums and interest, which are expected to total approximately $58 million in 2008 and $40 million in 2009. In return, to the extent the daily average NYMEX price for

West Texas Intermediate crude oil is less than $55.00, we will receive the difference between $55.00 and the daily average NYMEX price for West Texas Intermediate crude oil.

Our derivative positions also include price collars on 2,500 barrels per day of crude oil in 2008 with an average floor of $60.00 and an average ceiling of $80.13 and 15,000 MMBtu per day of gas with an average floor of $8.00 and an average ceiling of $12.11. In a typical collar transaction, we have the right to receive from the counterparty the excess of the floor price specified in the derivative agreement over a floating price based on a market index, multiplied by the specified quantity. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty this difference multiplied by the specified quantity. If we have less production than we have specified under the collars when the floating price exceeds the fixed price, we must make payments against which there is no offsetting production. If these payments become too large, the remainder of our business may be adversely affected.

See Item 7A "Quantitative and Qualitative Disclosures About Market Risk" for a summary of our current derivative positions. Since all of such derivative contracts are accounted for under mark to market accounting, we expect continued volatility in derivative gains or losses on our income statement as changes occur in the NYMEX price indexes.

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

We conduct operations offshore California, Louisiana, Texas, New Zealand and Vietnam. 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:

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

The majority of our oil production in California is dedicated to two customers and as a result, our credit exposure to those customers is significant.

We have entered into oil marketing arrangements with PMLP and with ConocoPhillips under which PMLP or ConocoPhillips purchase the majority of our net oil production in California. We generally do not require letters of credit or other collateral from PMLP or ConocoPhillips to support these trade receivables. Accordingly, a material adverse change in PMLP's or ConocoPhillips' financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

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 susceptible to damage from natural disasters, such as earthquakes, mudslides and fires, and our Gulf of Mexico operations are susceptible to hurricanes. Any of these operating hazards could cause serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs and other environmental damages, or property damage, all of 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. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. As a result, we do not believe that insurance coverage for the full potential liability, especially environmental liability, is currently available at reasonable cost. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur liability at a time when we are not able to obtain liability insurance, then our business, results of operations and financial condition could be materially adversely affected.

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

The successful acquisition 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 development and exploration operations may not result in any increases in reserves. Our operations may be curtailed, delayed or canceled as a result of:

- increases in the costs of, or inadequate access, to 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, 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 and 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 development activities. Future reserve increases and production may be dependent on our success in our exploration efforts, which may be unsuccessful.

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 and processing for our production. Substantially all of our oil and gas production is transported by pipelines and trucks and/or processed in facilities owned by third parties. The inability or unwillingness of these parties to provide transportation and processing services to us for a reasonable fee could result in our having to find transportation and processing alternatives, increased transportation and processing 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 operations and cash flows.

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 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.

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 broad 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, or their interpretations, 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 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.

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. 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 of our onshore California fields 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 coastal California gnatcatcher, which is a type of bird designated as threatened under the Federal 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;
- difficulty in assuming recoverable reserves, future production rates, operating costs, infrastructure requirements, environmental and other liabilities, and other factors beyond our control;
- 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.

Our foreign operations subject us to additional risks.

Our ownership and operations in New Zealand and Vietnam are subject to the various risks inherent in foreign operations. These risks may include the following:

- currency restrictions and exchange rate fluctuations;
- risks of increases in taxes and governmental royalties and renegotiation of contracts with governmental entities; and
- changes in laws and policies governing operations of foreign-based companies.

United States laws and policies on foreign trade, taxation and investment may also adversely affect our international operations. In addition, if a dispute arises from foreign operations, foreign courts may have exclusive jurisdiction over the dispute, or we may not be able to subject foreign persons to the jurisdiction of United States courts.

Local laws and customs in many countries differ significantly from those in the United States. In many foreign countries, particularly in those with developing economies like Vietnam, it is common to engage in business practices that are prohibited by United States regulations applicable to us. The U.S. Foreign Corrupt Practices Act prohibits corporations and individuals, including us and our employees, from engaging in certain activities to obtain or retain business or to influence a person working in an official capacity. Although we have implemented policies and procedures designed to ensure compliance with these laws, there can be no assurance that all of our employees, contractors and agents, including those based in or from countries where practices which violate such United States laws may be customary, will not take actions in violation of our policies. Any such violation, even if prohibited by our policies, could have a material adverse effect on our business. In addition, our foreign competitors that are not subject to the U.S. Foreign Corrupt Practices Act or similar laws may be able to secure business or other preferential treatment in such countries by means that such laws prohibit with respect to us.

Our net income could be negatively affected by stock based compensation charges.

We adopted Statement of Financial Accounting Standards (“SFAS”) No. 123R, "Share-Based Payment" (“SFAS 123R”) effective January 1, 2006. SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. Under SFAS 123R our stock appreciation rights are considered liability awards and are remeasured to fair value each reporting period with changes in fair value reported in earnings. As a result, we expect volatility in our earnings as our stock price changes.

We recognized $52 million, $55 million and $78 million of stock based compensation expense for the years ended December 31, 2007, 2006 and 2005, respectively.

Our results of operations could be adversely affected as a result of goodwill impairments.

In a purchase transaction, goodwill represents the excess of the purchase price plus the liabilities assumed, including deferred income taxes recorded in connection with the transaction, over the fair value of the net assets acquired. At December 31, 2007 goodwill totaled $536.8 million and represented 6% of our total assets.

Goodwill is not amortized, but instead must be tested at least annually for impairment by applying a fair-value based test. Goodwill is deemed impaired to the extent of any excess of its carrying amount over the residual fair value of the reporting unit. Such impairment could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and stockholders' equity. The most significant factors that could result in the impairment of our goodwill would be significant declines in oil and gas prices and/or reserve volumes which would result in a decline in the fair value of our oil and gas properties.

If oil and gas prices decrease, we may be required to take writedowns.

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 present value discounted at 10% of estimated future net cash flows from proved oil and gas reserves, net of estimated future income taxes (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 writedown if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. 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, writedowns of our oil and gas properties could occur. Writedowns required by these rules do not directly impact our cash flows from operating activities.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other actions have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets may be specific targets of terrorist organizations. These developments have subjected our operation to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

We face strong competition.

We face strong competition in all aspects of our business. Competition is particularly intense for prospective undeveloped leases and purchases of proved oil and gas reserves. There is also competition for the rigs and related equipment and services that are necessary for us to develop and operate our natural gas and oil properties. Our competitive position is also highly dependent on our ability to recruit and retain geological, geophysical and engineering expertise. We compete for prospects, proved reserves, field services and qualified oil and gas professionals with major and diversified energy companies. Some companies may be able to more successfully define, evaluate, bid for and purchase properties and prospects than us.

Our real estate entitlement efforts are subject to regulatory approvals.

Before being in a position to develop a property or to sell entitled land to a developer, we must obtain a variety of approvals from local, state and federal permitting authorities with respect to a number of matters including, without limitation:

- land use issues including zoning, subdivision, density, traffic, grading and site planning; and

- environmental issues including air and water quality and protection of endangered species and their habitats.

A portion of our surface acreage in Montebello has been designated as California Coastal Sage Scrub, a known habitat for the California Gnatcatcher, which is a species of bird designated as threatened under the Federal Endangered Species Act. We are consulting with the U.S. Fish and Wildlife Service and other regulatory agencies regarding proposed development footprints and habitat mitigation and protection strategies but the results of these consultations cannot be predicted.

Some of the regulatory approvals we are seeking are discretionary by nature. The entitlement approval process is often a lengthy and complex procedure requiring, among other things, the submission of development plans and reports and presentations at public hearings. Because of the provisional nature of these approvals and the concerns of various environmental and public interest groups, our ability to entitle and realize future income from our surface properties could be delayed, reduced, prevented or made more expensive.

Our real estate surface development efforts are greatly affected by the performance of the real estate market.

Our real estate activities are subject to numerous factors beyond our control, including: local real estate market conditions (both where our properties are located and in areas where our potential customers reside); substantial existing and potential competition; general national, regional and local economic conditions; fluctuations in interest rates and mortgage availability; and changes in demographic conditions. Real estate markets have historically been subject to strong periodic cycles driven by numerous factors beyond the control of market participants. Real estate investments often cannot easily be converted into cash and market values may be adversely affected by these economic circumstances, market fundamentals, competition and demographic conditions. Because of the effect these factors have on real estate values, it is difficult to predict with certainty the level of future sales or sales prices that will be realized for individual assets.

Our real estate surface development activities lack geographic diversification.

Our surface entitlement and development activities are limited to the following California counties: Los Angeles, Santa Barbara and San Luis Obispo. Economic and other events that adversely impact this comparatively narrow geographic region will have a direct negative impact on our real estate efforts.

Item 1B. *Unresolved Staff Comments*

Not applicable.

Item 3. *Legal Proceedings*

On November 15, 2005, the United States Court of Federal Claims issued a ruling granting the plaintiffs' motion for summary judgment as to liability and partial summary judgment as to damages in the breach of contract lawsuit Amber Resources Company et al. v. United States, Case No. 02-30c. The Court's ruling also denied the United States' motion to dismiss and motion for summary judgment. The United States Court of Federal Claims ruled that the federal government's imposition of new and onerous requirements that stood as a significant obstacle to oil and gas development breached agreements that it made when it sold 36 federal leases offshore California. The Court further ruled that the Government must give back to the current lessees the more than $1.1 billion in lease bonuses it had received at the time of sale. On October 31, 2006, the Court issued an unfavorable decision on the plaintiff's motion for partial summary judgment concerning plaintiffs' additional claims regarding the hundreds of millions of dollars that have been spent in the successful efforts to find oil and gas in the disputed lease area, and other matters. Plaintiffs filed a motion for final judgment on November 29, 2006 and the court granted such motion on January 11, 2007. Judgment on the $1.1 billion was filed January 12, 2007. The United States has filed its notice of appeal and Plaintiffs intend to file a cross-appeal concerning the Court's October 31, 2006 decision. No payments will be made until all appeals have either been waived or exhausted. We are among the current lessees of the 36 leases. Our share of the $1.1 billion award is in excess of $80 million if the plaintiffs are successful.

We are a defendant in various other lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty and could have a material adverse effect on our financial position, 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*

The following items were presented for approval to stockholders of record on September 25, 2007 at the special meeting of stockholders, held on November 6, 2007 in Houston, Texas:

	For	Against	Abstained or Withheld
(i) Issuance of PXP common stock to stockholders of Pogo Producing Company as a result of the merger of Pogo with and into PXP Acquisition a wholly owned subsidiary of PXP.	63,648,977	196,272	25,383
(ii) Approval of amendment to certificate of incorporation to increase the number of authorized common shares from 150,000,000 to 250,000,000	63,478,248	366,020	26,364

Of the 72,766,033 shares of common stock issued and outstanding on September 25, 2007, 63,870,632 were present, either in person or by proxy, at the special meeting.

PART II

Item 5. ***Market For Registrant's Common Equity, Related Stockholder Matters And Issuer Purchases Of Equity Securities***

Price Range of Common Stock

Our common stock is listed on the New York Stock Exchange under the symbol "PXP". The following table sets forth the range of high and low sales prices for our common stock as reported on the New York Stock Exchange Composite Tape for the periods indicated below:

	High	Low
2007		
1st Quarter	$49.42	$43.00
2nd Quarter	54.30	42.38
3rd Quarter	51.76	35.31
4th Quarter	57.08	43.91
2006		
1st Quarter	$46.90	$36.55
2nd Quarter	42.54	31.45
3rd Quarter	47.39	39.72
4th Quarter	49.73	40.20

At January 31, 2008 we had approximately 2,331 shareholders of record.

Dividend Policy

We have not paid any cash dividends and 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, repurchase shares of our common stock 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. As discussed in Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations—Financing Activities and Note 6 to the Consolidated Financial Statements, our credit facility and indentures restrict our ability to pay cash dividends.

Issuer Purchases of Equity Securities

Our Board of Directors has authorized the repurchase of up to $1.0 billion of PXP common stock. The shares will be repurchased from time to time in open market transactions or privately negotiated transactions at our discretion, subject to market conditions and other factors.

Item 6. *Selected Financial Data*

The following selected financial information was derived from our consolidated financial statements, including the consolidated balance sheets at December 31, 2007 and 2006 and the related consolidated statements of income and cash flows for each of the three years in the period ended December 31, 2007 and the notes thereto, appearing elsewhere in this report. You should read this information in conjunction with Item 7 "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.

	Year Ended December 31,				
	2007 (1)	2006	2005	2004 (2)	2003 (3)
	(In thousands, except per share amounts)				
Revenues	$1,272,840	$1,018,503	$ 944,420	$ 671,706	$ 304,090
Costs and Expenses					
Production costs	413,122	313,125	285,292	223,080	104,819
General and administrative	124,006	123,134	127,513	92,042	43,158
Depreciation, depletion, amortization and accretion	316,078	216,782	187,915	147,985	52,484
Gain on sale of oil and gas properties (4)	—	(982,988)	—	—	—
	853,206	(329,947)	600,720	463,107	200,461
Income from Operations	419,634	1,348,450	343,700	208,599	103,629
Other Income (Expense)					
Interest expense	(68,908)	(64,675)	(55,421)	(37,294)	(23,778)
Debt extinguishment costs (5)	—	(45,063)	—	(19,691)	—
Gain (loss) on mark-to-market derivative contracts (6)	(88,549)	(297,503)	(636,473)	(150,314)	847
Gain on termination of merger agreement (7)	—	37,902	—	—	—
Interest and other income (expense)	6,322	5,496	3,324	723	(159)
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	268,499	984,607	(344,870)	2,023	80,539
Income tax (expense) benefit					
Current	4,677	(142,378)	229	(375)	(1,224)
Deferred	(114,425)	(242,519)	130,629	7,192	(32,228)
Income (Loss) Before Cumulative Effect of Accounting Change	158,751	599,710	(214,012)	8,840	47,087
Cumulative effect of accounting change, net of tax (expense)/benefit (8)	—	(2,182)	—	—	12,324
Net Income (Loss)	$ 158,751	$ 597,528	$ (214,012)	$ 8,840	$ 59,411
Earnings (Loss) Per Share					
Basic					
Income (loss) before cumulative effect of accounting change	$ 2.02	$ 7.76	$ (2.75)	$ 0.14	$ 1.41
Cumulative effect of accounting change	—	(0.03)	—	—	0.37
Net income (loss)	$ 2.02	$ 7.73	$ (2.75)	$ 0.14	$ 1.78
Diluted					
Income (loss) before cumulative effect of accounting change	$ 1.99	$ 7.67	$ (2.75)	$ 0.14	$ 1.41
Cumulative effect of accounting change	—	(0.03)	—	—	0.37
Net income (loss)	$ 1.99	$ 7.64	$ (2.75)	$ 0.14	$ 1.78
Weighted Average Common Shares Outstanding					
Basic	78,627	77,273	77,726	63,542	33,321
Diluted	79,808	78,234	77,726	64,014	33,469

Table continued on following page

	Year Ended December 31,				
	2007 (1)	2006	2005	2004 (2)	2003 (3)
	(In thousands of dollars)				
Cash Flow Data					
Net cash provided by operating activities	$ 588,112	$ 674,981	$ 463,334	$ 363,219	$ 118,278
Net cash (used in) provided by investing activities	(2,243,137)	811,999	(168,420)	5,414	(368,710)
Net cash provided by (used in) financing activities	1,679,572	(1,487,633)	(294,907)	(368,465)	250,781

	As of December 31,				
	2007 (1)	2006	2005	2004 (2)	2003 (3)
	(In thousands of dollars)				
Balance Sheet Data					
Assets					
Cash and cash equivalents	$ 25,446	$ 899	$ 1,552	$ 1,545	$ 1,377
Other current assets	649,474	183,897	291,780	256,622	87,104
Property and equipment, net	8,377,227	2,107,524	2,251,887	2,184,962	965,748
Goodwill	536,822	158,515	173,858	170,467	147,251
Other assets	104,382	12,393	22,865	19,649	10,788
	$ 9,693,351	$ 2,463,228	$ 2,741,942	$ 2,633,245	$ 1,212,268
Liabilities and Stockholders' Equity					
Current liabilities	$ 818,046	$ 460,192	$ 363,998	$ 426,395	$ 155,086
Long-term debt	3,305,000	235,500	797,375	635,468	487,906
Other long-term liabilities	272,627	170,574	603,422	381,524	65,429
Deferred income taxes	1,959,431	466,279	258,810	319,483	149,591
Stockholders' equity	3,338,247	1,130,683	718,337	870,375	354,256
	$ 9,693,351	$ 2,463,228	$ 2,741,942	$ 2,633,245	$ 1,212,268

(1) Reflects the acquisition of Pogo effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.
(2) Reflects the acquisition of Nuevo effective May 14, 2004.
(3) Reflects the acquisition of 3TEC Energy Corporation effective June 1, 2003.
(4) Represents gain on the sale of oil and gas properties to subsidiaries of Oxy of $345 million and gain on the sale of non-producing oil and gas properties to Statoil of $638 million. Gain on the sale of these oil and gas properties was recognized because the sale caused a significant change in the relationship between capitalized costs and proved reserves.
(5) In connection with the retirement of our 7.125% Senior Notes and 8.75% Senior Subordinated Notes in 2006 we recorded $45.1 million of debt extinguishment costs. In connection with the retirement of the debt assumed in the acquisition of Nuevo in 2004, we recorded $19.7 million of debt extinguishment costs.
(6) We do not use hedge accounting for certain of our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. Consequently, these derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts in the income statement.
(7) Represents the fee received by us, net of expense, in connection with a terminated merger in 2006.
(8) Cumulative effect of adopting SFAS 123R—"Share-Based Payment" in 2006 and SFAS No. 143—"Accounting for Asset Retirement Obligations" in 2003.

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.

Company Overview

We are an independent oil and gas company primarily engaged in the activities of acquiring, developing, exploring and producing oil and gas properties primarily in the United States. We own oil and gas properties with principal operations in:

- the Los Angeles and San Joaquin Basins onshore California;
- the Santa Maria Basin offshore California;
- the Piceance and Wind River Basins in the Rocky Mountains;
- the Permian Basin in West Texas and New Mexico;
- the Anadarko Basin in the Texas Panhandle; and
- the South Texas and Gulf Coast regions, including the Gulf of Mexico.

We also have interests in exploration prospects offshore New Zealand and Vietnam.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil or gas prices above the maximum fixed amount specified in the derivative agreement. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy (see "Derivative Instruments and Hedging").

Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. Our primary sources of liquidity are cash generated from our operations and our senior revolving credit facility. At December 31, 2007, we had approximately $687 million of availability under our senior revolving credit facility. We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our senior revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies, anticipated capital expenditures and expenditures under our stock repurchase program. In December 2007, we executed definitive agreements to sell oil and gas properties for approximately $1.75 billion that have or are expected to close in the first quarter of 2008 that will provide us additional funds to repurchase stock and reduce debt. See Items 1 and 2 "Business and Properties—Divestments." In addition, the majority of our capital expenditures and expenditures under our stock repurchase program are discretionary and could be curtailed if our cash flows declined from expected levels.

Acquisitions

In November 2007, we acquired Pogo for approximately 40 million shares of common stock and approximately $1.5 billion in cash. Pogo was engaged in oil and gas exploration, development, acquisition and production activities on its properties primarily located in the onshore United States, Vietnam and New Zealand. We accounted for the transaction under purchase accounting rules effective November 6, 2007.

In May 2007, we acquired certain properties in the Piceance Basin from a private company for $975 million in cash and one million shares of common stock. The Piceance Basin properties include interests in oil and gas producing properties in the Mesaverde geologic section of the Piceance Basin in Colorado, plus associated midstream assets, including a 25% interest in CVGG.

General

We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration and development activities are capitalized. 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 writedown if our capitalized costs exceed the allowed "ceiling." 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, writedowns of our oil and gas properties could occur. Writedowns 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 estimated proved reserves, our reserve volumes and our revenues, profitability and cash flow.

Our oil and gas production expenses include salaries and benefits of personnel involved in production activities (including stock based compensation), steam gas costs, electricity 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 estimated proved reserves. For the purposes of computing depletion, estimated proved reserves are redetermined as of the end of each year and on an interim basis when deemed necessary.

General and administrative expenses ("G&A") consist primarily of salaries and related benefits of administrative personnel (including stock based compensation), office rent, systems costs and other administrative costs.

Results Overview

In addition to fluctuations as a result of operating in the oil and gas industry, our earnings are subject to volatility due to: (i) gains and losses on derivative contracts subject to mark-to-market accounting as changes occur in the NYMEX price indexes; and (ii) stock appreciation rights ("SARs"), which are accounted for as liability awards under SFAS 123R and are remeasured to fair value each reporting period. The fair value of SARs is related to the market price of our common stock and will fluctuate with movements in our stock price.

In 2007, we reported net income of $158.8 million, or $1.99 per diluted share. Net income for the period includes an $88.5 million pre-tax derivative mark-to-market loss. Our results reflect the acquisitions of the Piceance Basin properties effective May 31, 2007 and Pogo effective November 6, 2007.

In 2006, we reported net income of $597.5 million, or $7.64 per diluted share. Net income for the period includes a $983.0 million pre-tax gain on sales of oil and gas properties, a $297.5 million pre-tax derivative mark-to-market loss, debt extinguishment costs of $45.1 million, a $37.9 million gain on the termination of a merger agreement, and a non-cash, after-tax expense related to the adoption of SFAS 123R of $2.2 million, or $0.03 per share.

In 2005, primarily as a result of a $636.5 million derivative mark-to-market loss, we reported a net loss of $214.0 million, or $2.75 per share.

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,		
	2007 (1)	2006 (2)	2005
Sales Volumes			
Oil and liquids sales (MBbls)	18,124	18,975	18,671
Gas (MMcf)			
Production	29,312	20,629	29,359
Used as fuel	2,302	4,823	5,241
Sales (3)	27,010	15,806	24,118
MBOE			
Production	23,010	22,413	23,564
Sales (3)	22,625	21,609	22,691
Daily Average Volumes			
Oil and liquids sales (Bbls)	49,655	51,985	51,154
Gas (Mcf)			
Production	80,307	56,519	80,435
Used as fuel	6,307	13,214	14,358
Sales (3)	74,000	43,305	66,077
BOE			
Production	63,041	61,405	64,560
Sales (3)	61,986	59,202	62,166
Unit Economics (in dollars) (4)			
Average NYMEX Prices			
Oil	$ 72.36	$ 66.23	$ 56.61
Gas	6.86	7.21	8.62
Average Realized Sales Price Before Derivative Transactions			
Oil (per Bbl)	$ 61.60	$ 55.62	$ 46.76
Gas (per Mcf)	5.68	6.73	7.15
Per BOE	56.12	53.76	45.96
Costs and Expenses per BOE			
Production costs			
Lease operating expenses	$ 9.98	$ 8.32	$ 5.97
Steam gas costs	4.57	2.95	3.32
Electricity	1.76	1.76	1.35
Production and ad valorem taxes	1.44	1.15	1.03
Gathering and transportation	0.50	0.31	0.43
DD&A (oil and gas properties)	12.92	8.96	7.39

(1) Reflects the acquisition of Pogo effective November 6, 2007 and the Piceance Basin properties effective May 31, 2007.

(2) Reflects the sale of oil and gas properties to subsidiaries of Oxy effective October 1, 2006.

(3) 2005 amounts represent volumes presented on a basis consistent with 2006 and 2007. See Note 4 below.

(4) Prior to 2006, gas revenues included amounts attributable to buy-sell contracts related to our thermal recovery operations in California and associated costs were included in steam gas costs. As a result of our adoption of EITF 04-13 effective January 1, 2006, in 2007 and 2006 certain costs associated with such contracts are reflected as a reduction in gas revenues and the associated volumes are not included in sales volumes. Amounts per BOE reflected in the foregoing table are based on production volumes for 2005 and sales volumes for 2006 and 2007.

The following table reflects cash receipts (payments) made with respect to derivative contracts during the periods presented (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Contracts accounted for using hedge accounting			
Oil sales	$ —	$ —	$ (53,044)
Gas sales	—	—	(6,255)
Gas purchases	—	—	10,293
Elimination of crude oil swaps	—	—	(147,280)
Mark-to-market contracts			
Oil sales	(103,784)	(89,596)	(279,982)
Gas sales	235	—	—
Gas purchases	—	(11,425)	—
Elimination of crude oil collars	—	(593,283)	(145,383)

Comparison of Year Ended December 31, 2007 to Year Ended December 31, 2006

Oil and gas revenues. Oil and gas revenues increased $253.7 million, or 25%, to $1.3 billion for 2007 from $1.0 billion for 2006 primarily due to the absence of an oil revenue hedging loss in 2007 and higher realized prices.

Oil revenues excluding the effects of hedging, increased $60.9 million to $1.1 billion for 2007 from $1.0 billion for 2006 reflecting higher realized prices ($113.3 million) partially offset by lower sales volumes ($52.4 million). Our average realized price for oil increased $5.98 to $61.60 per Bbl for 2007 from $55.62 per Bbl for 2006. The increase is primarily attributable to an improvement in the NYMEX oil price, which averaged $72.36 per Bbl in 2007 versus $66.23 per Bbl in 2006. Oil sales volumes decreased 2.3 MBbls per day to 49.7 MBbls per day in 2007 from 52.0 MBbls per day in 2006 due to the property divestitures in 2006. Hedging had the effect of decreasing our oil revenues by $145.8 million, or $7.68 per Bbl, in 2006. Hedging had no impact on oil revenues in 2007.

Gas revenues increased $47.1 million to $153.4 million in 2007 from $106.3 million in 2006 due to increased sales volumes ($63.6 million) partially offset by lower realized prices ($16.5 million). Our average realized price for gas was $5.68 per Mcf in 2007 compared to $6.73 per Mcf in 2006. Our realized price for gas decreased due to a decrease in the index price for natural gas ($0.35 per Mcf) and the higher differentials for the Piceance Basin properties which we acquired in 2007. Our average differential for gas sold in the Piceance Basin was $3.33 per Mcf during 2007. Gas sales volumes increased from 43.3 MMcf per day in 2006 to 74.0 MMcf per day in 2007, primarily reflecting the impact of the acquisition of the Piceance Basin properties and Pogo, partially offset by the 2006 property sale.

Lease operating expenses. Lease operating expenses increased $46.1 million, to $225.8 million in 2007 from $179.7 million in 2006. The increase is primarily attributable to higher expenditures for well workovers, repairs and maintenance, labor costs, general cost increases from service providers and the impact of our acquisition and divestment activity. On a per unit basis, lease operating expenses increased to $9.98 per BOE in 2007 versus $8.32 per BOE in 2006 due to increased costs.

Steam gas costs. Steam gas costs increased $39.7 million, to $103.5 million in 2007 from $63.8 million in 2006, primarily reflecting higher steam volumes and higher cost of gas used in steam generation. In 2007 we burned approximately 16.8 Bcf of natural gas at a cost of approximately $6.17 per Mcf compared to 14.6 Bcf at a cost of approximately $4.36 per Mcf in 2006. The higher cost per Mcf in 2007 reflects that substantially all of the gas burned in 2007 was purchased while in 2006 approximately 20% of the gas burned was produced from the Company's properties and costs for these volumes consisted only of transportation costs.

Electricity. Electricity increased $1.8 million, to $39.8 million in 2007 from $38.0 million in 2006, primarily reflecting higher cost for purchased electricity and an increase in usage. On a per unit basis, electricity was $1.76 per BOE in 2007 and 2006.

Production and ad valorem taxes. Production and ad valorem taxes increased $7.8 million, to $32.6 million in 2007 from $24.8 million in 2006 primarily reflecting increased volumes from the Pogo acquisition and the effect of increased oil prices.

Gathering and transportation expenses. Gathering and transportation expenses increased $4.6 million, to $11.4 million in 2007 from $6.8 million in 2006, primarily reflecting the Piceance Basin and Pogo acquisitions.

General and administrative expense. G&A expense increased $0.9 million, to $124.0 million in 2007 from $123.1 million in 2006 due to an increase in other G&A expense of $5.0 million ($75.9 million in 2007 versus $70.9 million in 2006) as a result of increased personnel costs due to the acquisitions in 2007, offset by a decrease in stock based compensation in 2007 ($48.1 million in 2007 versus $52.2 million in 2006). The decrease in stock based compensation in 2007 primarily reflects lower expense for SARs, which fluctuates with changes in our stock price and other factors that impact fair value.

G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. Capitalized costs were $44.6 million in 2007 compared to $34.8 million in 2006, primarily reflecting increased costs and our acquisition, exploration and development activities.

Depreciation, depletion and amortization, or DD&A. DD&A expense increased $99.1 million, to $306.3 million in 2007 from $207.2 million in 2006. Approximately $97.4 million of the increase was attributable to our oil and gas DD&A, primarily due to a higher per unit rate. Our oil and gas unit of production rate increased to $12.92 per BOE in 2007 compared to $8.96 per BOE in 2006. The increase primarily reflects the effect of our acquisitions, increased future development costs, higher cost reserve additions and exploration costs.

Accretion expense. Accretion expense increased $0.2 million, to $9.8 million in 2007 from $9.6 million in 2006.

Interest expense. Interest expense increased $4.2 million, to $68.9 million in 2007 from $64.7 million in 2006 primarily due to higher outstanding debt related to the Piceance Basin and Pogo acquisitions. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization. We capitalized $34.6 million and $7.9 million of interest in 2007 and 2006, respectively. The increase in capitalized interest is due to a higher unevaluated property balance related to the Piceance Basin and Pogo acquisitions.

Loss on mark-to-market derivative contracts. We do not currently use hedge accounting for our derivative instruments. Consequently, these derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.

As a result of the significant increase in oil prices, we recognized losses related to mark-to-market derivative contracts of $88.5 million and $297.5 million in 2007 and 2006, respectively.

Interest and other income. Interest and other income increased $0.8 million to $6.3 million in 2007 compared to $5.5 million in 2006.

Income tax expense. Our 2007 income tax expense was $109.7 million, reflecting an annual effective tax rate of 41%, as compared with income tax expense of $384.9 million and an effective tax rate of 39% for 2006. Variances in our annual effective tax rate from the 35% federal statutory rate primarily result from the effect of state income taxes and permanent differences primarily related to expenses that are not deductible because of Internal Revenue Service limitations. Our current benefit primarily reflects the effect of tax refunds received in 2007.

In 2008, we expect our overall effective tax rate to be between 40% and 43% reflecting the effect of state income taxes and permanent differences primarily related to expenses that are not deductible because of IRS limitations. In 2008, we expect our current tax expense to be higher as a result of anticipated asset sales.

Comparison of Year Ended December 31, 2006 to Year Ended December 31, 2005

Oil and gas revenues. Oil and gas revenues increased $75.2 million, to $1.0 billion for 2006 from $0.9 billion for 2005 primarily due to higher realized prices.

Oil revenues excluding the effects of hedging, increased $182.4 million to $1.1 billion for 2006 from $0.9 billion for 2005 reflecting higher realized prices ($165.5 million) and higher sales volumes ($16.9 million). Our average realized price for oil increased $8.86 to $55.62 per Bbl for 2006 from $46.76 per Bbl for 2005. The increase is primarily attributable to an improvement in the NYMEX oil price, which averaged $66.23 per Bbl in 2006 versus $56.61 per Bbl in 2005. Oil sales volumes increased 0.8 MBbls per day to 52.0 MBbls per day in 2006 from 51.2 MBbls per day in 2005 as higher sales volumes from our California properties was partially offset by lower volumes due to the property divestitures in 2006.

Hedging had the effect of decreasing our oil revenues by $145.8 million, or $7.68 per Bbl in 2006 compared to $139.1 million or $7.45 per Bbl in 2005. The 2006 amount represents the deferred losses related to our 2006 swaps that were terminated in 2005. The 2005 amount includes $106.2 million of deferred losses related to our 2005 swaps that were terminated in 2004. These losses were deferred in Accumulated Other Comprehensive Income (“OCI”) and recognized as a reduction to oil revenues as the hedged production was sold.

Gas revenues, excluding the effects of hedging, decreased $103.5 million to $106.3 million in 2006 from $209.8 million in 2005 due to decreased sales volumes ($55.9 million), a decrease in revenues due to a change in the presentation of certain costs related to buy-sell contracts ($36.9 million) and lower realized prices ($10.7 million). Gas revenues for 2005 include $36.9 million attributable to buy-sell contracts related to our thermal recovery operations in California. As a result of our adoption of EITF 04-13 effective January 1, 2006 (See Note 1 to the consolidated financial statements), in 2006 certain costs associated with such contracts are reflected as a reduction in gas revenues. Our average realized price for gas was $6.73 per Mcf in 2006 compared to $7.15 per Mcf in 2005. Hedging had the effect of decreasing our 2005 gas revenues by $3.1 million or $0.10 per Mcf.

Gas sales volumes decreased from 66.1 MMcf per day in 2005 to 43.3 MMcf per day in 2006 primarily reflecting the effect of property divestitures in the second quarter of 2005 and the fourth quarter of 2006.

Lease operating expenses. Lease operating expenses increased $39.1 million, to $179.7 million in 2006 from $140.6 million in 2005. The increase is primarily attributable to higher expenditures for well workovers and repairs and maintenance, increased labor costs and general cost increases from service providers. On a per unit basis, lease operating expenses increased to $8.32 per BOE in 2006 versus $5.97 per BOE in 2005 due to increased costs and lower volumes.

Steam gas costs. Steam gas costs decreased $14.5 million, to $63.8 million in 2006 from $78.3 million in 2005. Steam gas costs for 2005 include certain costs ($36.9 million) attributable to buy-sell contracts that after the adoption of EITF 04-13 are included in gas revenues. On a basis comparable to 2006, 2005 steam gas costs would have been $41.3 million, or $1.75 per BOE, compared to $63.8 million, or $2.95 per BOE, in 2006, primarily reflecting higher steam volumes partially offset by a decrease in the cost of natural gas used in the process.

Electricity. Electricity increased $6.2 million, to $38.0 million in 2006 from $31.8 million in 2005, primarily reflecting higher cost for purchased electricity and an increase in usage. On a per unit basis, electricity increased to $1.76 per BOE in 2006 versus $1.35 per BOE in 2005.

Production and ad valorem taxes. Production and ad valorem taxes increased $0.3 million, to $24.8 million in 2006 from $24.5 million in 2005 primarily reflecting the effect of increased oil and gas prices partially offset by the effect of the property divestitures in 2005 and 2006.

Gathering and transportation expenses. Gathering and transportation expenses decreased $3.3 million, to $6.8 million in 2006 from $10.1 million in 2005 primarily reflecting the effect of the property divestitures in 2005 and 2006.

General and administrative expense. G&A expense decreased $4.4 million, to $123.1 million in 2006 from $127.5 million in 2005 due to lower stock based compensation expense ($52.2 million in 2006 versus $77.2 million in 2005) partially offset by increases in other G&A expenses ($70.9 million in 2006 versus $50.3 million in 2005). The decrease in stock based compensation in 2006 primarily reflects lower expense for SARs which fluctuates with changes in our stock price and other factors that impact fair value and approximately $19 million of expense in 2005 related to restricted stock units that vested based on the performance of our common stock. The increase in other G&A expenses is primarily due to increased compensation costs reflecting higher costs to attract and retain a highly qualified workforce, aircraft costs and contributions. G&A expense for 2006 includes $9.6 million in stock based compensation expense and $2.9 million in cash payments related to officer resignations and organizational changes.

G&A expense does not include amounts capitalized as part of our acquisition, exploration and development activities. Capitalized costs increased to $34.8 million in 2006 compared to $24.5 million in 2005, primarily reflecting increased costs.

Depreciation, depletion and amortization, or DD&A. DD&A expense increased $26.9 million, to $207.2 million in 2006 from $180.3 million in 2005. Approximately $25.5 million of the increase was attributable to our oil and gas DD&A, primarily due to a higher per unit rate. Our oil and gas unit of production rate increased to $8.96 per BOE in 2006 compared to $7.39 per BOE in 2005. The increase primarily reflects the effect of increased future development costs, higher cost reserve additions and exploration costs.

Accretion expense. Accretion expense increased $2.0 million, to $9.6 million in 2006 from $7.6 million in 2005, primarily reflecting higher estimated future costs of our abandonment obligations.

Gain on sale of oil and gas properties. On September 29 and November 1, 2006, we closed on sales of oil and gas properties and recognized pre-tax gains totaling $983.0 million.

Interest expense. Interest expense increased $9.3 million, to $64.7 million in 2006 from $55.4 million in 2005 primarily due to higher interest costs related to certain of our derivative transactions. Interest expense does not include interest capitalized on oil and gas properties not subject to amortization. We capitalized $7.9 million and $3.5 million of interest in 2006 and 2005, respectively.

Debt extinguishment costs. In connection with the retirement of our 7.125% Senior Notes and 8.75% Senior Subordinated Notes, in 2006 we recorded $45.1 million of debt extinguishment costs.

Gain (loss) on mark-to-market derivative contracts. We do not currently use hedge accounting for our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. Consequently, these derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.

As a result of the significant increase in oil prices, we recognized losses related to mark-to-market derivative contracts of $297.5 million and $636.5 million in 2006 and 2005, respectively. Cash payments related to these contracts that settled totaled $101.0 million and $280.0 million in 2006 and 2005, respectively. In addition, in 2005 we paid $145.4 million in connection with the elimination of our 2006 collars and in 2006 we paid $593.3 million in connection with the elimination of our 2007 and 2008 collars.

Gain on termination of merger agreement. On April 24, 2006, we announced that we had entered into a definitive agreement to acquire Stone Energy Corporation. On June 22, 2006, the agreement was terminated by Stone in order for Stone to enter into a merger agreement with another company. In connection with the termination of the merger agreement we received a termination fee of $43.5 million and recognized a gain, net of merger related costs, of $37.9 million.

Interest and other income. Interest and other income increased $2.2 million to $5.5 million in 2006 compared to $3.3 million in 2005.

Income tax expense. Our 2006 income tax expense was $384.9 million, reflecting an annual effective tax rate of 39%. Variances in our annual effective tax rate from the 35% federal statutory rate are caused by the effect of state income taxes and permanent differences primarily related to expenses that are not deductible because of IRS limitations. Our current expense primarily reflects the effect of the taxable gains on the sales of oil and gas properties during 2006 and the related effect of the utilization of net operating loss carryforwards and enhanced oil recovery ("EOR") credits.

EOR credits are credits against federal and state income taxes for certain costs related to extracting high-cost oil, utilizing certain prescribed "enhanced" (tertiary) recovery methods. EOR credits are subject to a phase out according to the level of average domestic crude oil prices. As a result of the increase in oil prices in 2005, companies did not earn EOR credits in 2006.

Our 2005 income tax expense was a benefit of $130.9 million, reflecting an annual effective tax rate of 38%. Variances in the annual effective tax rate from the 35% federal statutory rate are caused by state income taxes, EOR credits and permanent differences primarily reflecting expenses that are not deductible because of IRS limitations.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from our operations and our senior revolving credit facility. At December 31, 2007, we had approximately $687 million of availability under our senior revolving credit facility. We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our senior revolving credit facility to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies, anticipated capital expenditures and expenditures under our stock repurchase program. In December 2007, we executed definitive agreements to sell oil and gas properties for approximately $1.75 billion that have or are expected to close in the first quarter of 2008 that will provide us additional funds to repurchase stock and reduce debt. See Items 1 and 2 "Business and Properties—Divestments". In addition, the majority of our capital expenditures and expenditures under our stock repurchase program are discretionary and could be curtailed if our cash flows declined from expected levels.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of increases in oil or gas prices above the maximum fixed amount specified in the derivative agreement. The level of derivative activity depends on our view of market conditions, available derivative prices and our operating strategy.

Our ability to raise capital depends on the current state of the financial markets, which are subject to general economic and industry conditions. Therefore, the availability of and cost of capital in the financial markets could negatively affect our liquidity position. Our current liquidity is supported by no near term debt maturities with our senior revolving credit facility maturing on November 12, 2012.

Working Capital

At December 31, 2007, we had a working capital deficit of approximately $143 million. Our working capital is affected by fluctuations in the fair value of our commodity derivative instruments and stock appreciation rights. As of December 31, 2007, we had net short-term liabilities of $57 million and $39 million for derivatives and stock appreciation rights, respectively. We generally have a working capital deficit because we use excess cash to pay down borrowings under our senior revolving credit facility.

Financing Activities

7¾% Senior Notes. In June 2007, we issued $600 million of 7¾% Senior Notes due 2015 at par. We may redeem all or part of the 7¾% Senior Notes on or after June 15, 2011 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to June 15, 2010 we may, at our option, redeem up to 35% of the 7¾% Senior Notes with the proceeds from certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7¾% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

7% Senior Notes. In March 2007, we issued $500 million of 7% Senior Notes due 2017 at par. We may redeem all or part of the 7% Senior Notes on or after March 15, 2012 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to March 15, 2010 we may, at our option, redeem up to 35% of the 7% Senior Notes with the proceeds from certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase.

The 7% Senior Notes and 7¾% Senior Notes are our general unsecured senior obligations. The 7% Senior Notes and 7¾% Senior Notes are jointly and severally guaranteed on a senior unsecured basis by certain of our existing domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. The 7% Senior Notes and 7¾% Senior Notes rank senior in right of payment to all of our existing and future subordinated indebtedness; *pari passu* in right of payment with any of our existing and future unsecured indebtedness that is not by its terms subordinated to the 7% Senior Notes and 7¾% Senior Notes; effectively junior to our existing and future secured indebtedness, including indebtedness under our senior revolving credit facility, to the extent of our assets constituting collateral securing that indebtedness; and effectively subordinate to all existing and future indebtedness and other liabilities (other than indebtedness and liabilities owed to us) of our non-guarantor subsidiaries.

The indentures governing the 7% Senior Notes and 7¾% Senior Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company. At December 31, 2007, we were in compliance with the covenants contained in the indentures for the 7% Senior Notes and 7¾% Senior Notes.

Senior Revolving Credit Facility. On November 6, 2007, we entered into an Amended and Restated Credit Agreement (the "Amended Credit Agreement"), which amended and restated PXP's five-year senior revolving credit facility, which closed May 31, 2007. The Amended Credit Agreement provides for an initial borrowing base of $2.9 billion and a conforming borrowing base of $2.6 billion, which will be redetermined on an annual basis, with us and the lenders 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. The borrowing base will be automatically reduced to equal the conforming borrowing base on the earlier of (a) the first anniversary of the closing of the Pogo acquisition, (b) the first date on which we issue additional senior notes permitted by the Amended Credit Agreement and (c) the sale (in one or more transactions) of oil and gas properties not covered by the most recently delivered reserve report and the issuance of equity interest for an aggregate consideration of $300 million or more. Additionally, the Amended Credit Agreement contains a $250 million sub-limit on letters of credit, a $50 million commitment for swingline loans, and matures on November 6, 2012. Collateral consists of 100% of the shares of stock in certain of our domestic, and 65% of certain foreign, subsidiaries and mortgages covering at least 75% of the total present value of our domestic oil and gas properties.

Amounts borrowed under the Amended Credit Agreement bear an annual interest rate, at our election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 1.00% to 2.00%; (ii) the greater of (1) the prime rate, as determined by JPMorgan Chase Bank and (2) the federal funds rate, plus ½ of 1%, plus an additional variable amount ranging from 0% to .5% for each of (1) and (2); and (iii) the over-night federal funds rate plus an additional variable amount ranging from 1.00% to 2.00% for swingline loans. The additional variable 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 Amended Credit Agreement to the conforming borrowing base and (2) our long-term debt ratings. Commitment fees and letter of credit fees under the Amended Credit Agreement are based on the utilization rate and our long-term debt rating. Commitment fees range from .225% to .375% of the amount available for borrowing. Letter of credit fees range from 1.0% to 2.0%. The issuer of any letter of credit receives an issuing fee of .125% of the undrawn amount. The effective interest rate on our borrowings under the Amended Credit Agreement was 6.51% at December 31, 2007.

The Amended Credit Agreement contains negative covenants that limit our ability, as well as the ability of our restricted 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, guarantee other indebtedness, enter into agreements that restrict dividends from subsidiaries, enter into certain types of swap agreements, enter into take-or-pay or other prepayment arrangements, merge or consolidate and enter into transactions with affiliates. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined) of no greater than 4.25 to 1.

At December 31, 2007, we had $7.7 million in letters of credit outstanding under the Amended Credit Agreement. At that date we were in compliance with the covenants contained in the Amended Credit Agreement and could have borrowed the full amount available under the Amended Credit Agreement.

Short-term Credit Facility. We may make borrowings from time to time until May 1, 2008 not to exceed at any time the maximum principal amount of $50 million. No advance under the short-term facility may have a term exceeding fourteen days and all amounts outstanding are due and payable no later than May 1, 2008. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and the Company. No amounts were outstanding under the short-term credit facility at December 31, 2007.

Subsequent Event. On February 13, 2008, we entered into an amendment to the Amended Credit Agreement. The amendment reduces the borrowing base and commitments to $2.8 billion from $2.9 billion upon the closing of the sale of certain properties to XTO. The borrowing base and commitments will be further reduced to $2.5 billion and $1.9 billion, respectively, upon the closing of the sale of certain properties to Oxy. In addition, the amendment allows us to redeem or repurchase up to $1.0 billion of our common stock upon the closing of the XTO and Oxy sales subject to certain conditions being met.

Cash Flows

	Year Ended December 31,		
	2007	2006	2005
	(in millions of dollars)		
Cash provided by (used in):			
Operating activities	$ 588.1	$ 675.0	$ 463.3
Investing activities	(2,243.1)	812.0	(168.4)
Financing activities	1,679.6	(1,487.6)	(294.9)

Net cash provided by operating activities was $588.1 million in 2007, $675.0 million in 2006 and $463.3 million in 2005. The decrease in net cash provided by operating activities in 2007 was a result of income tax payments of $118.9 million in 2007 primarily related to the gain recognized in connection with PXP's 2006 oil and gas property sales and Pogo's 2007 sale of its Canadian operations prior to the acquisition date and the $37.9 million merger termination fee, net of certain merger related costs, received in 2006. The increase in cash provided by operating activities in 2006 is primarily a result of increased oil and gas prices. As discussed below, certain of our derivative cash payments are classified as financing or investing activities.

Net cash used in investing activities was $2,243.1 million in 2007, reflecting the acquisition of the Piceance properties for $975.4 million, and Pogo for $298.0 million (net of cash acquired), $770.4 million of oil and gas property additions, derivative settlements of $99.9 million and $59.1 million increase in restricted cash. Net cash provided by investing activities was $812.0 million in 2006, reflecting property sales proceeds of $1.6 billion, net of additions to oil and gas properties of $634.3 million and derivative settlements of $93.4 million. Net cash used in investing activities was $168.4 million in 2005 primarily reflecting additions to oil and gas properties of $509.1 million partially offset by property sales proceeds of $346.5 million. Derivative settlements related to derivatives that are not accounted for as hedges and do not contain a significant financing element are reflected as investing activities.

Net cash provided by financing activities in 2007 was $1.7 billion, reflecting net borrowings on our senior revolving credit facility of $2.0 billion and proceeds from the issuance of our 7¾% Senior Notes and 7% Senior Notes of $1.1 billion, partially offset by the redemption of the Pogo notes of $1.3 billion. Net cash used in financing activities in 2006 was $1.5 billion, primarily reflecting payments totaling $524.9 million to redeem all $250 million outstanding principal of our 7.125% Senior Notes and purchase $274.9 million of our $275 million outstanding principal of our 8.75% Senior Subordinated Notes, $298.4 million to repurchase stock, $621.9 million in financing derivative settlements and $36.5 million in net repayments under our revolving credit facilities. Net cash used in financing activities in 2005 was $294.9 million, primarily reflecting $162.0 million in net borrowings under our credit facility and the payment of $459.5 million in financing derivative settlements. Under SFAS 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", certain of our derivatives are deemed to contain a significant financing element and cash settlements with respect to such derivatives are required to be reflected as financing activities.

Capital Requirements

We have made and will continue to make substantial capital expenditures for the acquisition, development, exploration and production of oil and gas. We have a capital budget for 2008, excluding acquisitions, of approximately $1.15 billion. 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, derivative obligations, debt service obligations, expenditures under our stock repurchase program, contingencies and anticipated capital expenditures. In addition, the majority of our capital expenditures and expenditures under our stock repurchase program are discretionary and could be curtailed if our cash flows decline from expected levels.

Stock Repurchase Program

In December 2007, our Board of Directors authorized the repurchase of up to $1.0 billion of our common stock replacing the previous $500 million authorization that had approximately $158 million remaining. The shares will be repurchased from time to time in open market transactions or privately negotiated transactions at our discretion, subject to market conditions and other factors. As of December 31, 2007, we have not made any purchases under this program.

Commitments and Contingencies

Contractual obligations. At December 31, 2007, the aggregate amounts of contractually obligated payment commitments for the next five years are as follows (in thousands):

	Total	2008	2009 and 2010	2011 and 2012	Thereafter
Operating leases	$ 59,291	$ 13,675	$ 19,860	$ 13,997	$ 11,759
Commodity derivative contracts	98,289	58,212	40,077	—	—
Long-term debt	3,305,000	—	—	2,205,000	1,100,000
Interest on debt	1,374,662	226,976	453,952	432,130	261,604
Stock appreciation rights	68,378	63,106	5,272	—	—
Asset retirement obligation	195,408	11,328	6,865	20,316	156,899
Tax uncertainties	20,073	—	—	20,073	—
Other	28,542	5,568	11,540	10,599	835
	$5,149,643	$378,865	$537,566	$2,702,115	$1,531,097

Operating leases relate primarily to obligations associated with aircraft, our office facilities and certain cogeneration operations in California. The obligation for commodity derivative contracts represents the cost to purchase crude oil put options that will be paid when such options are settled.

The long-term debt and interest payments amounts consist of amounts due under our credit facility and interest payments to maturity. The principal amount under our credit facility varies based on our cash inflows and outflows and the amounts reflected in this table assume the principal amount outstanding at December 31, 2007 remains outstanding to maturity with interest and commitment fees calculated at the rates in effect at December 31, 2007.

Asset retirement obligations represent the estimated fair value at December 31, 2007 of our obligations with respect to the retirement/abandonment of our oil and gas properties. Each reporting period the liability is accreted to its then present value. The ultimate settlement amount and the timing of the settlement of such obligations are unknown because they are subject to, among other things, federal, state and local regulation and economic factors. See Note 5 to the Consolidated Financial Statements.

Stock appreciation rights ($63.1 million current and $5.3 million long-term) represent the net liability for the deemed vested portion of SARs. The liability at December 31, 2007 is calculated based on our closing stock price and other factors at that date. The ultimate settlement amount of such liability is unknown because settlements are based on the market price of our common stock at the time the SARs are exercised. The current SAR liability represents the vested awards as well as the awards expected to vest during the following year and is reflected in the table in 2008 because the holders have the right to exercise the awards. The awards do not all expire in 2008, so a portion of the amount will potentially be paid in a later year. The long-term SAR liability is deemed to be a contractual obligation in the year the awards vest. At December 31, 2007 we had approximately 2.8 million SARs outstanding of which 1.4 million were vested. If all of the vested SARs were exercised, based on $54.00, the price of our common stock as of December 31, 2007, we would pay $75.6 million to holders of the SARs. In 2007 we made cash payments of $8.3 million for SARs that were exercised during that period. See "Critical Accounting Policies and Factors that May Affect Future Results—Stock based compensation."

Tax uncertainties represent potential cash payments related to uncertain tax positions taken or expected to be taken in a tax return.

Other contractual obligations represent our liability for environmental remediation obligations, pension obligations and post-retirement benefits.

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 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 cannot assure you that we will be able to collect on these indemnities.

We estimate our 2008 cash expenditures related to plugging, abandonment and remediation will be approximately $11.3 million. Due to the long life of our onshore California reserve base we do not expect our cash outlays for such expenditures for these properties will increase significantly in the next several years. At the Point Arguello Unit, offshore California, the companies from which we purchased our interests retained responsibility for the majority of the 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 are responsible for our 69.3% share of other abandonment costs which primarily consist of well-bore abandonments, conductor removals and site cleanup and preparation. 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 sale of certain properties offshore California in December 2004, we retained the responsibility for certain abandonment costs, including removing, dismantling and disposing of the existing offshore platforms. The present value of such abandonment costs, $42 million ($81 million undiscounted), are included in our asset retirement obligation as reflected on our consolidated balance sheet. In addition, we agreed to guarantee the performance of the purchaser with respect to the remaining abandonment obligations related to the properties (approximately $46 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2007, the escrow account had a balance of $6 million. The fair value of our guarantee, $0.4 million, is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

For a further discussion of our obligations to incur plugging, abandonment and remediation costs, see Items 1 and 2 "Business and Properties—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 crude oil and natural gas properties and the marketing, transportation and storage of crude oil. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

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, releases of 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. During 2007, 2006 and 2005 sales to ConocoPhillips accounted for 45%, 54% and 44%, respectively, of our total revenues and sales to PMLP accounted for 31%, 41% and 38%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect; however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions.

The nine financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A+ or better and all but one of the financial institutions are participating lenders in our revolving credit facility. As of December 31, 2007, we were in a net derivative liability position with all but two of such counterparties with a net asset position of $2.2 million.

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 reserve volumes and value. 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 derivative arrangements relating to a portion of our oil and gas production to achieve a more predictable cash flow, as well as to reduce our exposure to adverse price fluctuations. Derivative instruments used are typically fixed price swaps and collars and purchased puts and calls. While the use of these types of 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 and cash flows is limited when commodity prices increase.

We do not use hedge accounting for our derivative instruments, because the derivatives do not qualify or we have elected not to use hedge accounting. These derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently as a gain or loss on mark-to-market derivative contracts on the income statement. Consequently, we expect continued volatility in our reported earnings as changes occur in the NYMEX indexes. Since our remaining derivative position consists primarily of crude oil put options, there will continue to be volatility in derivative gains or losses on our income statement; however, our ultimate potential loss will be limited to the cost of the options. Cash flow is only impacted to the extent the actual settlements under the contracts result in making or receiving a payment from the counterparty.

The estimation of fair values of derivative instruments requires substantial judgment. We estimate the fair values of our derivatives using an option-pricing model. The option-pricing model utilizes various factors including NYMEX price quotations, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the agreements and the resulting estimated future cash inflows (outflows) over the lives of the derivative instruments are discounted using LIBOR interest rate curves. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts and interest rates.

For a further discussion concerning our risks related to oil and gas prices and our hedging programs, see Item 7A "Qualitative and Quantitative Disclosures about Market Risks".

Writedowns 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 present value discounted at 10% of estimated future net cash flows from proved oil and gas reserves, net of estimated future income taxes (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 writedown if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. 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, writedowns of our oil and gas properties could occur. Writedowns required by these rules do not directly impact our cash flows from operating activities. At December 31, 2007, the ceiling with respect to our oil and gas properties exceeded the net capitalized costs of those properties by approximately $3.6 billion.

Oil and gas reserves. With the exception of 1% of our reserve volumes, our 2007 proved reserve information is based on estimates prepared by outside engineering firms and estimates prepared by us and audited by outside engineering firms. Estimates prepared by others may be higher or lower than these estimates.

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

You should not assume that the standardized measure reflects 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 reserve base (approximately 63% at December 31, 2007) is comprised of oil properties that are sensitive to oil price volatility. Historically, we have experienced significant upward and downward revisions to our reserves volumes and values as a result of changes in year-end oil and gas prices and the corresponding adjustment to the projected economic life of such properties. Prices for oil and gas are likely to continue to be volatile, resulting in future downward and upward revisions to our reserve base. Certain of our properties are sensitive to gas price differentials in the Rocky Mountains. An increase in the gas differential to NYMEX for these properties could cause the proved undeveloped reserves to become uneconomic. We currently have 81.4 MMBOE of proved undeveloped reserves in the Rocky Mountains.

Future development and abandonment costs. Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, reservoir depth and characteristics, currently available procedures and consultations with engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. Changes in estimated future abandonment costs would affect our liability for asset retirement obligations, future accretion expense and DD&A.

DD&A. Our rate for 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 development program, as well as future economic conditions.

Our oil and gas DD&A rate at December 31, 2007 was $15.89 per BOE. Based on our estimated proved reserves and our net oil and gas properties subject to amortization at December 31, 2007: (i) a 5% increase in our costs subject to amortization would increase our DD&A rate by approximately $0.79 per BOE and (ii) a five percent negative revision to proved reserves would increase our DD&A rate by approximately $0.81 per BOE. We estimate that our oil and gas DD&A rate will be in a range between approximately $15.35 and $15.45 per BOE subsequent to the asset divestments closed or expected to close in the first quarter of 2008.

Stock based compensation. Under SFAS 123R stock appreciation rights are considered liability awards and are remeasured to fair value each reporting period with changes in fair value reported in earnings. As a result, we expect volatility in our earnings as our stock price changes.

We utilize the Black-Scholes option pricing model to measure the fair value of our stock appreciation rights and in the case of restricted stock unit grants that include common stock price based performance targets we utilize a Monte-Carlo simulation model to estimate the fair value and the number of restricted stock units expected to be issued in the future. Expected volatility is based on the historical volatility of our common stock and other factors. We use historical experience with exercise and post exercise behavior to determine expected life. The use of such models requires substantial judgment with respect to expected life, volatility, expected returns and other factors.

We recognized $52 million, $55 million and $78 million of stock based compensation expense for the years ended December 31, 2007, 2006 and 2005, respectively.

Goodwill. In a purchase transaction, goodwill represents the excess of the purchase price plus the liabilities assumed, including deferred income taxes recorded in connection with the merger, over the fair value of the net assets acquired. At December 31, 2007, goodwill totaled $537 million and represented approximately 6% of our total assets.

We account for goodwill in accordance with SFAS No. 142, “Goodwill and Other Intangible Assets” (“SFAS 142’). Goodwill is not amortized; it is tested at least annually for impairment at a level of reporting referred to as a reporting unit. Impairment is the condition that exists when the carrying amount of goodwill exceeds its implied fair value. A two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized (if any). The first step of the goodwill impairment test, used to identify potential impairment, compares the fair value of a reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired, thus the second step of the impairment test is unnecessary.

The second step of the goodwill impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of goodwill.

We follow the full cost method of accounting and all of our producing properties are located in the United States. We have determined that for the purpose of performing an impairment test in accordance with SFAS 142, we have one reporting unit. SFAS 142 states that quoted market prices in active markets are the best evidence of fair value and shall be used as the basis for the measurement, if available. Accordingly, we use the quoted market price of our common stock to determine the fair value of our reporting unit.

An impairment of goodwill could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and stockholders’ equity. The most significant factors that could result in the impairment of our goodwill would be significant declines in oil and gas prices and/or estimated reserve volumes which would result in a decline in the fair value of our reporting unit.

Recent Accounting Pronouncements

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements” which is effective for fiscal years beginning after November 15, 2007 and for interim periods within those years. This statement defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115”, which is effective for fiscal years beginning after November 15, 2007. This statement permits an entity to choose to measure many financial instruments and certain other items at fair value at specified election dates. Subsequent unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, "Amendment of FASB Interpretation No. 39" ("FSP FIN 39-1"), which amended FIN 39, to indicate that the following fair value amounts could be offset against each other if certain conditions of FIN 39 are otherwise met: (a) those recognized for derivative instruments executed with the same counterparty under a master netting arrangement and (b) those recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from the same master netting arrangement as the derivative instruments. In addition, a reporting entity is not precluded from offsetting the derivative instruments if it determines that the amount recognized upon payment or receipt of cash collateral is not a fair value amount. FSP FIN 39-1 is effective at the beginning of the first fiscal year after November 15, 2007. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51" ("SFAS 160"). SFAS 160 requires companies with noncontrolling interests to disclose such interests clearly as a portion of equity but separate from the parent's equity. The noncontrolling interest's portion of net income must also be clearly presented on the Income Statement. SFAS 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and we do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). SFAS 141R broadens the guidance of SFAS 141, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. It broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations. SFAS 141R expands on required disclosures to improve the statement users' abilities to evaluate the nature and financial effects of business combinations. SFAS 141R is effective for fiscal year beginning on or after December 15, 2008. We are currently evaluating the potential impact of this statement on future business combinations.

Item 7A. *Quantitative And Qualitative Disclosures About Market Risk*

Commodity Price Risk

Our primary market risk is oil and gas commodity prices. Historically the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. All derivative instruments are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recognized currently in our income statement as a gain or loss on mark-to-market derivative contracts. Cash flows are only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. We do not currently use hedge accounting for our derivative instruments. If a derivative is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Other Comprehensive Income ("OCI"), a component of Stockholders' Equity, until the hedged oil and gas production is sold. Realized gains and losses on derivative instruments that are designated as a hedge and qualify for hedge accounting are generally included in oil and gas revenues in the period the hedged volumes are sold. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain in OCI until the related product has been delivered.

See Note 4 to the Consolidated Financial Statements “Derivative Instruments and Hedging Activities” for a discussion of our derivative activities.

During 2007 and 2006, we acquired downside crude oil price protection for a substantial amount of our production with $55.00 put option contracts. We assumed, through the acquisition of Pogo, 2008 crude oil collars with an average floor of $60.00 and an average ceiling of $80.13 as well as 2008 gas collars with an average floor of $8.00 and an average ceiling of $12.11. At December 31, 2007, we had the following open commodity derivative positions, none of which were designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price	Index
Sales of Crude Oil Production				
2008				
Jan-Dec	Put options	42,000 Bbls	$55.00 Strike price	WTI
Jan-Dec	Collar	2,500 Bbls	$60.00 Floor—$80.13 Ceiling	WTI
2009				
Jan-Dec	Put options	32,500 Bbls	$55.00 Strike price	WTI
Sales of Natural Gas Production				
2008				
Jan-Dec	Collar	15,000 MMBtu	$8.00 Floor—$12.11 Ceiling	Henry Hub

The only cash settlements we are required to make on the purchased put options are option premiums and interest, which are expected to total approximately $58 million in 2008 and $40 million in 2009. Such amounts are not included in the fair value of derivatives not designated as hedging instruments in the table below.

In a typical collar transaction, we have the right to receive from the counterparty the excess of the floor price specified in the derivative agreement over a floating price based on a market index, multiplied by the specified quantity. If the floating price exceeds the floor price and is less than the ceiling price, no payment is required by either party. If the floating price exceeds the ceiling price, we must pay the counterparty this difference multiplied by the specified quantity. If we have less production than we have specified under the collars when the floating price exceeds the fixed price, we must make payments against which there is not offsetting production.

The fair value of outstanding crude oil and gas commodity derivative instruments at December 31, 2007 and the change in fair value that would be expected from a 10% price increase or decrease is shown below (in millions):

		Effect of 10%	
	Fair Value	Price Increase	Price Decrease
Derivatives not designated as hedging instruments	$5.1	$(12.1)	$13.9

The fair value of the commodity derivative contracts are estimated based on quoted prices from independent reporting services compared to the contract price of the agreement, and approximate the gain or loss that would have been realized if the contracts had been closed out at period end. All 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% increase or 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 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 nine financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A+ or better and all but one of the financial institutions are participating lenders in our revolving credit facility. We have a net derivative liability with the one counterparty that is not a participating lender in our revolving credit facility. As of December 31, 2007, we were in a net derivative liability position with all but two of such counterparties with a net asset position of $2.2 million.

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

Price differentials. Our realized wellhead oil and gas prices are lower than the NYMEX index level as a result of area and quality differentials. See Items 1 and 2. Business and Properties—Product Markets and Major Customers.

Approximately 50% of our gas production is sold monthly off of industry recognized, published index pricing and the remainder is priced daily on the spot market. Fluctuations between the two pricing mechanisms can significantly impact the overall differential to the Henry Hub.

Interest Rate Risk

We are exposed to market risk due to the floating interest rates on our senior revolving credit facility and our short-term credit facility. At December 31, 2007, $2.2 billion was outstanding under our senior revolving credit facility at an effective interest rate of 6.5%. The carrying value of our senior revolving credit facility approximates its fair value, as interest rates are variable, based on prevailing market rates. Based on the $2.2 billion outstanding under our senior revolving credit facility at December 31, 2007, on an annualized basis a 1% change in the effective interest rate would result in a $22.1 million change in our interest costs.

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*

Not Applicable.

Item 9A. *Controls And Procedures*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on this evaluation, our Chief Executive Officer and our Chief Financial Officer believe that the disclosure controls and procedures as of December 31, 2007 were 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.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and implemented by the Company's Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2007. The Company excluded Pogo Producing Company LLC and its subsidiaries from its assessment of internal control over financial reporting as of December 31, 2007 because Pogo was acquired on November 6, 2007. Pogo is a wholly owned subsidiary of the Company whose total assets and total revenues represent 56% and 10%, respectively, of the related consolidated financial statement amounts, as of and for the year ended December 31, 2007.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Controls

Except for the potential changes noted in the following paragraph relating to the Pogo acquisition, there were no changes in our internal control over financial reporting during the quarter ended December 31, 2007 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In November 2007, we completed the acquisition of Pogo. Management continues to integrate the acquired company's historical internal control over financial reporting with our internal control over financial reporting. This integration may lead to changes in these controls in future fiscal periods but management does not yet know whether these changes will materially affect our internal control over financial reporting. Management expects the integration process to be completed during 2008.

Item 9B. *Other Information*

Not Applicable

PART III

Item 10. *Directors, Executive Officers And Corporate Governance*

Information regarding our directors and executive officers will be included in an amendment to this Form 10-K or in the proxy statement for the 2008 annual meeting of stockholders, in either case, to be filed within 120 days after December 31, 2007, and is incorporated by reference to this report.

Directors and Executive Officers of Plains Exploration & Production Company

Listed below are our directors and executive officers, their age as of January 31, 2008 and their business experience for the last five years.

Directors

James C. Flores, age 48, Chairman of the Board, President and Chief Executive Officer and a Director since September 2002. He has been Chairman of the Board and Chief Executive Officer of PXP since December 2002, and President since March 2004. He was also Chairman of the Board of Plains Resources, Inc. ("Plains Resources," now known as Vulcan Energy Corporation) from May 2001 to June 2004 and is currently a director of Vulcan Energy. He was Chief Executive Officer of Plains Resources from May 2001 to December 2002. He was Co-founder as well as Chairman, Vice Chairman and Chief Executive Officer at various times from 1992 until January 2001 of Ocean Energy, Inc., an oil and gas company.

Isaac Arnold, Jr., age 72, Director since May 2004. He also was a director of Nuevo Energy Company from 1990 to May 2004. He has been a director of Legacy Holding Company since 1989 and Legacy Trust Company since 1997 and is currently Director Emeritus of both. He has been a director of Cullen Center Bank & Trust since its inception in 1969 and has been a director of Cullen/Frost Bankers, Inc. and is currently Director Emeritus of both. Mr. Arnold is a trustee of the Museum of Fine Arts Houston and The Texas Heart Institute. Mr. Arnold received his B.B.A. from the University of Houston in 1959.

Alan R. Buckwalter, III, age 61, Director since March 2003. He 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 Service Corporation International, BCM Technologies, Inc., the Texas Medical Center and Greater Houston Area Red Cross. He sits on the Audit Committee and is Chairman of the Compensation Committee for Service Corporation International.

Jerry L. Dees, age 68, Director since September 2002. He also was a director of Plains Resources from 1997 to December 2002. Mr. Dees has been a director of Geotrace Technologies, Inc. since 2005. He 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.

Tom H. Delimitros, age 67, Director since September 2002. He also was a director of Plains Resources from 1988 to December 2002. He 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 a director for three privately owned companies. Previously, he has served as President and CEO for Magna Corporation, (now Baker Petrolite, a unit of Baker Hughes). Mr. Delimitros currently serves on two Development Committees for the College of Engineering at the University of Washington in Seattle and is Chairman of their Diamond Award Committee for Engineering Excellence.

Thomas A. Fry, III, age 63, Director since November 2007. He was also a director of Pogo from 2004 to November 2007. He has been the President of National Ocean Industries Association ("NOIA") since December 2000. Before joining NOIA, Mr. Fry served as the Director of the Department of Interior's Bureau of Land Management and has also served as the Director of the Minerals Management Service.

Robert L. Gerry III, age 70, Director since May 2004. He was also a director of Nuevo from 1990 to May 2004. Mr. Gerry currently serves as a director of Integrity Bank. He has been chairman and chief executive officer of Vaalco Energy, Inc., a publicly traded independent oil and gas company which does not compete with PXP, since 1997. From 1994 to 1997, Mr. Gerry was vice chairman of Nuevo. Prior to that, he was president and chief operating officer of Nuevo since its formation in 1990. Mr. Gerry also currently serves as a trustee of Texas Children's Hospital.

Charles G. Groat, age 67, Director since November 2007. He was also a director of Pogo from 2005 to November 2007. Dr. Groat currently serves as the Director of the Center for International Energy and Environment Policy and as the Director of the Energy and Earth Resources Graduate Program at the University of Texas at Austin. Before joining the University of Texas at Austin, Dr. Groat served for more than six years as Director of the U.S. Geological Survey, having been appointed by President Clinton and retained by President Bush.

John H. Lollar, age 69, Director since September 2002. He also was a director of Plains Resources from 1995 to December 2002. He 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, where he is a member of the Compensation Committee and Chairman of the Audit Committee. 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.

Executive Officers

James C. Flores, age 48, Chairman of the Board, President and Chief Executive Officer and a Director since September 2002. He has been Chairman of the Board and Chief Executive Officer of PXP since December 2002, and President since March 2004. He was also Chairman of the Board of Plains Resources, Inc. ("Plains Resources," now known as Vulcan Energy Corporation) from May 2001 to June 2004 and is currently a director of Vulcan Energy. He was Chief Executive Officer of Plains Resources from May 2001 to December 2002. He was Co-founder as well as Chairman, Vice Chairman and Chief Executive Officer at various times from 1992 until January 2001 of Ocean Energy, Inc., an oil and gas company.

Doss R. Bourgeois, age 50, Executive Vice President—Exploration and Production since June 2006. He was PXP's Vice President of Development from April 2006 to June 2006. He was also PXP's Vice President Eastern Development Unit from May 2003 to April 2006. Prior to that time, Mr. Bourgeois was Vice President from August 1993 to May 2003 at Ocean Energy, Inc.

Winston M. Talbert, age 45, Executive Vice President and Chief Financial Officer since June 2006. He joined PXP in May 2003 as Vice President Finance & Investor Relations and in May 2004, Mr. Talbert became Vice President Finance & Treasurer. Prior to joining PXP, Mr. Talbert was Vice President and Treasurer at Ocean Energy, Inc. from August 2001 to May 2003 and Assistant Treasurer from October 1999 to August 2001.

John F. Wombwell, age 46, Executive Vice President, General Counsel and Secretary since September 2003. He was also Plains Resources' Executive Vice President, General Counsel, and Secretary from September 2003 to June 2004. He was previously a Senior Executive Officer with two New York Stock Exchange traded companies, including serving as General Counsel of ExpressJet Holdings, Inc. from April 2002 until September 2003. Prior to that time, Mr. Wombwell was a partner at the national law firm of Andrews Kurth LLP with a practice focused on representing public companies with respect to corporate and securities matters.

Item 11. *Executive Compensation*

Information regarding executive compensation will be included in an amendment to this Form 10-K or in the proxy statement for the 2008 annual meeting of stockholders 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 will be included in an amendment to this Form 10-K or in the proxy statement for the 2008 annual meeting of stockholders and is incorporated by reference to this report.

Item 13. *Certain Relationships And Related Transactions, And Director Independence*

Information regarding certain relationships and related transactions will be included in an amendment to this Form 10-K or in the proxy statement for the 2008 annual meeting of stockholders and is incorporated by reference to this report.

Item 14. *Principal Accounting Fees And Services*

Information regarding principal accounting fees and services will be included in an amendment to this Form 10-K or in the proxy statement for the 2008 annual meeting of stockholders and is incorporated by reference to this report.

PART IV

Item 15. *Exhibits, Financial Statement Schedules*

(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 July 17, 2007, by and among Plains Exploration & Production Company, PXP Acquisition LLC and Pogo Producing Company (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed July 18, 2007, File No. 1-31470).
2.2	Purchase and Sale Agreement dated December 14, 2007, by and among Plains Exploration & Production Company, Plains Resources Inc., PXP Hell's Gulch LLC, PXP East Plateau LLC, PXP Brush Creek LLC, PXP Piceance LLC, Pogo Producing Company LLC, Pogo Panhandle 2004 LP and Latigo Petroleum Texas LP, and OXY USA Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 17, 2007, File No. 1-31470 (the "December 17, 2007 Form 8-K")).
2.3	Asset Purchase & Sale Agreement between Plains Exploration & Production Company and Laramie Energy, LLC, dated April 18, 2007 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed April 24, 2007, File No. 1-31470 (the "April 24, 2007 Form 8-K")).
2.4	Membership Interests Purchase & Sale Agreement between Plains Exploration & Production Company and Laramie Energy, LLC, dated as of April 18, 2007 (incorporated by reference to Exhibit 10.2 to the April 24, 2007 Form 8-K.
2.5	Amendment to Purchase and Sale Agreement dated as of September 29, 2006, by and among Plains Exploration & Production Company, PXP Gulf Coast Inc., PXP Texas Limited Partnership, Brown PXP Properties, LLC, PXP Louisiana L.L.C., and PXP Texas, Inc. and Vintage Production California LLC, Occidental of Elk Hills, Inc., Occidental Permian Ltd., Oxy USA Inc. and Occidental International Oil & Gas Ltd. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed October 4, 2006, File No. 1-31470).
2.6	Purchase and Sale Agreement dated as of September 15, 2006, and effective as of September 1, 2006, between Plains Exploration & Production Company and Statoil Gulf of Mexico LLC (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed September 18, 2006, File No. 1-31470).
2.7	Purchase and Sale Agreement dated as of August 6, 2006, and effective as of October 1, 2006, by and among Plains Exploration & Production Company, PXP Gulf Coast Inc., PXP Texas Limited Partnership, and Brown PXP Properties, LLC, and Vintage Production California LLC, Occidental of Elk Hills, Inc., Occidental Permian Ltd., Oxy USA Inc., and Occidental International Oil & Gas Ltd. (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed August 8, 2006, File No. 1-31470).
3.1	Certificate of Incorporation of Plains Exploration & Production Company (incorporated by reference to Exhibit 3.1 to the Company's Amendment No. 2 to Registration Statement on Form S-1 (file no. 333-90974) filed on October 3, 2002 (the "Amendment No. 2 to Form S-1")).

Exhibit Number	Description
3.2	Certificate of Amendment to the Certificate of Incorporation of Plains Exploration & Production Company dated May 14, 2004 (incorporated by reference to Exhibit 3.1 to the Company's Quarterly Report on Form 10-Q for the period ending June 30, 2004, File No. 1-31470).
3.3*	Certificate of Amendment to the Certificate of Incorporation of Plains Exploration & Production Company dated November 6, 2007.
3.4	Bylaws of Plains Exploration & Production Company (incorporated by reference to Exhibit 3.2 to the Amendment No. 2 to Form S-1).
4.1	Indenture, dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed March 13, 2007, File No. 1-31470 (the "March 13, 2007 Form 8-K")).
4.2	First Supplemental Indenture, dated March 13, 2007, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (including form of 7% Senior Note) (incorporated by reference to Exhibit 4.2 to the March 13, 2007 Form 8-K).
4.3*	Second Supplemental Indenture, dated as of June 5, 2007, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Plains Resources Inc., PXP East Plateau LLC, PXP Brush Creek LLC, PXP CV Pipeline LLC, PXP Hell's Gulch LLC, PXP Piceance LLC, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee.
4.4	Third Supplemental Indenture, dated as of June 19, 2007, to Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, the Subsidiary Guarantors parties thereto, and Wells Fargo Bank, N.A., as Trustee (including form of 7¾% Senior Note) (incorporated by reference to Exhibit 4.2 to the Company's current Report on Form 8-K filed June 19, 2007, File No. 1-31470).
4.5*	Fourth Supplemental Indenture, dated as of November 14, 2007, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Laramie Land & Cattle Company, LLC, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee.
4.6*	Fifth Supplemental Indenture, dated as of January 29, 2008, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Latigo Gas Group, LLC, Latigo Gas Holdings, LLC, Latigo Gas Services, LP, Latigo Holding (Texas), LLC, Latigo Investments, LLC, Latigo Petroleum, Inc., Latigo Petroleum Texas LP, Pogo Energy, Inc., Pogo Panhandle 2004, L.P., Pogo Producing Company LLC, Pogo Producing (Texas Panhandle) Company, PXP Aircraft LLC, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee.
4.7*	Sixth Supplemental Indenture, dated as of February 13, 2008, to the Indenture dated as of March 13, 2007, among Plains Exploration & Production Company, Pogo Partners, Inc., Pogo Producing (San Juan) Company, the Subsidiary Guarantors parties thereto and Wells Fargo Bank, N.A., as Trustee.
4.8	Amended and Restated Credit Agreement, dated as of November 6, 2007, among Plains Exploration & Production Company, as borrower, each of the lenders that is a signatory thereto, and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed November 6, 2007, File No. 1-31470).

Exhibit Number	Description
4.9	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of February 13, 2008, among Plains Exploration & Production Company, as borrower, each of the lenders that is a signatory thereto, and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed February 20, 2008, File No. 1-31470).
4.10	Indenture, dated as of September 23, 2005, between Pogo Producing Company and The Bank of New York Trust Company, N.A., as Trustee (including form of 6.875% Senior Subordinated Note) (incorporated by reference to Exhibit 4.1 to Pogo's Current Report on Form 8-K filed September 29, 2005, File No. 1-7792).
4.11	First Supplemental Indenture, dated as of November 6, 2007, to the Indenture dated as of September 23, 2005, between PXP Acquisition LLC and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.3 to the November 26, 2007 Form 8-K).
4.12	Second Supplemental Indenture, dated as of November 20, 2007, to the Indenture dated as of September 23, 2005, by and between Pogo Producing Company LLC and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.6 to the November 26, 2007 Form 8-K).
10.1	Consulting Agreement, dated as of January 19, 2006, between Montebello Land Company LLC and Cook Hill Properties LLC (incorporated by reference to Exhibit 10.3 to the Company's Form 10-K for the year ended December 31, 2005, File No. 1-31470 (the "2005 10-K").
10.2	Consulting Agreement, dated as of January 19, 2006, between Lompoc Land Company LLC and Cook Hill Properties LLC (incorporated by reference to Exhibit 10.4 to the 2005 10-K).
10.3	Consulting Agreement, dated as of January 19, 2006, between Arroyo Grande Land Company LLC and Cook Hill Properties LLC (incorporated by reference to Exhibit 10.5 to the 2005 10-K).
10.4	Crude Oil Marketing Agreement, dated July 15, 2004, by and among Plains Exploration & Production Company, Arguello, Inc., PXP Gulf Coast Inc., and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.7 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, File 1-31470 (the "2004 10-K")).
10.5	First Amendment to Crude Oil Marketing Agreement, dated as of October 19, 2004, among Plains Exploration & Production Company, Arguello, Inc., PXP Gulf Coast Inc., and Plains Marketing, L.P (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, File No. 1-31470).
10.6	Crude Oil Purchase Agreement dated January 1, 2000, between Plains Exploration & Production Company (as successor to Nuevo Energy Company) and ConocoPhillips (as successor to Tosco Corporation) (incorporated by reference to Exhibit 10.1 to Nuevo Energy Company's Current Report on Form 8-K filed February 23, 2000, File No. 0-10537).
10.7*	Plains Exploration & Production Company 2002 Stock Incentive Plan.
10.8	Form of Plains Restricted Stock Award Agreement under the 2002 Incentive Plan (incorporated by reference to Exhibit 10.19 to the Company's Form 10-K for the year ended December 31, 2002, File No. 1-31470).
10.9*	Form of Restricted Stock Unit Agreement under the 2002 Stock Incentive Plan.

Exhibit Number	Description
10.10	Form of Plains Stock Appreciation Rights Agreement under the 2002 Incentive Plan (incorporated by reference to Exhibit 10.11 to the September 30, 2006 10-Q).
10.11	Amended and Restated Plains Exploration & Production Company 2004 Stock Incentive Plan (incorporated by reference to Exhibit 4.1 to the Company's Quarterly Report on form 10-Q for the quarter ended September 30, 2007, File No. 1-31470).
10.12	Form of Plains Restricted Stock Award Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.36 to the Company's Form 10-K for the year ended December 31, 2006, File No. 1-31470).
10.13*	Form of Restricted Stock Unit Agreement under the 2004 Stock Incentive Plan.
10.14	Form of Plains Stock Appreciation Rights Agreement under the 2004 Incentive Plan (incorporated by reference to Exhibit 10.9 to the September 30, 2006 10-Q).
10.15*	Amended and Restated Plains Exploration & Production Company Executives' Long-Term Retention and Deferred Compensation Agreement effective as of February 10, 2006.
10.16*	Amended and Restated Plains Exploration & Production Company Long-Term Retention and Deferral Agreement for James C. Flores.
10.17*	Amended and Restated Plains Exploration & Production Company Long-Term Retention Agreement for John F. Wombwell.
10.18*	Amended and Restated Employment Agreement, effective as of June 9, 2004, between Plains Exploration & Production Company and James C. Flores.
10.19*	Amended and Restated Employment Agreement, effective as of June 9, 2004, between Plains Exploration & Production Company and John F. Wombwell.
10.20*	Amended and Restated Employment Agreement, effective as of November 8, 2006, between Plains Exploration & Production Company and Winston M. Talbert.
10.21*	Amended and Restated Employment Agreement, effective as of November 8, 2006, between Plains Exploration & Production Company and Doss R. Bourgeois.
10.22*	Form of Election for Director Deferral of Restricted Stock Awards.
10.23*	Summary of Named Executive Officer Salary Increases.
10.24	Summary of Director Compensation Program (incorporated by reference to Exhibit 10.5 to the March 31, 2006 10-Q).
21.1*	List of Subsidiaries of Plains Exploration & Production Company.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
23.3*	Consent of Ryder Scott Company, L.P.
23.4*	Consent of Miller & Lents, Ltd.
31.1*	Rule 13(a)-14(a)/15d-14(a) Certificate of the Chief Executive Officer.
31.2*	Rule 13(a)-14(a)/15d-14(a) Certificate of the Chief Financial Officer.
32.1**	Section 1350 Certificate of the Chief Executive Officer.
32.2**	Section 1350 Certificate of the Chief Financial Officer.

* Filed herewith.

** Furnished herewith.

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: February 27, 2008	/s/ JAMES C. FLORES James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive 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: February 27, 2008	/s/ JAMES C. FLORES James C. Flores, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)
Date: February 27, 2008	/s/ ISAAC ARNOLD, JR. Isaac Arnold, Jr., Director
Date: February 27, 2008	/s/ ALAN R. BUCKWALTER, III Alan R. Buckwalter, III, Director
Date: February 27, 2008	/s/ JERRY L. DEES Jerry L. Dees, Director
Date: February 27, 2008	/s/ TOM H. DELIMITROS Tom H. Delimitros, Director
Date: February 27, 2008	/s/ THOMAS A. FRY, III Thomas A. Fry, III, Director
Date: February 27, 2008	/s/ ROBERT L. GERRY, III Robert L. Gerry, III, Director
Date: February 27, 2008	/s/ CHARLES G. GROAT Charles G. Groat, Director
Date: February 27, 2008	/s/ JOHN H. LOLLAR John H. Lollar, Director
Date: February 27, 2008	/s/ WINSTON M. TALBERT Winston M. Talbert, Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: February 27, 2008	/s/ CYNTHIA A. FEEBACK Cynthia A. Feeback, Vice President / Controller and Chief Accounting Officer (Principal Accounting Officer)

PLAINS EXPLORATION & PRODUCTION COMPANY

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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 Registered Public Accounting Firm

To The Board of Directors and Shareholders
of Plains Exploration & Production Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income and comprehensive income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Plains Exploration & Production Company and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Notes 7 and 9 to the consolidated financial statements, the Company changed its method of accounting for its uncertain tax positions in connection with its adoption of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" effective January 1, 2007, and its method of accounting for its stock-based compensation in connection with its adoption of Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment" effective January 1, 2006.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Annual Report on Internal Control Over Financial Reporting, management has excluded Pogo Producing Company LLC and its subsidiaries from its assessment of internal control over financial reporting as of December 31, 2007 because it was acquired by the Company in a purchase business combination during the fourth quarter of 2007. We have also excluded Pogo Producing Company LLC from our audit of internal control over financial reporting. Pogo Producing Company LLC is a wholly owned subsidiary whose total assets and total revenues represent 56% and 10%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2007.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2008

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands of dollars)

	December 31, 2007	December 31, 2006
ASSETS		
Current Assets		
Cash and cash equivalents	$ 25,446	$ 899
Restricted cash	59,092	—
Accounts receivable	304,972	113,193
Inventories	18,394	12,394
Deferred income taxes	229,893	51,084
Other current assets	37,123	7,226
	674,920	184,796
Property and Equipment, at cost		
Oil and natural gas properties—full cost method		
Subject to amortization	7,340,238	2,624,277
Not subject to amortization	1,951,783	142,096
Other property and equipment	85,928	41,392
	9,377,949	2,807,765
Less allowance for depreciation, depletion and amortization	(1,000,722)	(700,241)
	8,377,227	2,107,524
Goodwill	536,822	158,515
Other Assets	104,382	12,393
	$ 9,693,351	$2,463,228
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 319,583	$ 131,639
Commodity derivative contracts	79,938	95,162
Royalties and revenues payable	132,919	38,159
Stock appreciation rights	63,106	57,429
Interest payable	25,330	1,143
Income taxes payable	3,492	94,272
Accrued merger expenses	77,980	—
Other current liabilities	115,698	42,388
	818,046	460,192
Long-Term Debt		
Revolving credit facility	2,205,000	235,500
7¾% Senior Notes	600,000	—
7% Senior Notes	500,000	—
	3,305,000	235,500
Other Long-Term Liabilities		
Asset retirement obligation	184,080	133,420
Commodity derivative contracts	33,821	18,114
Other	54,726	19,040
	272,627	170,574
Deferred Income Taxes	1,959,431	466,279
Commitments and Contingencies (Note 10)		
Stockholders' Equity		
Common stock, $0.01 par value, 250.0 million shares authorized, 112.8 million and 79.2 million shares issued at December 31, 2007 and 2006, respectively	1,128	792
Additional paid-in capital	2,711,617	964,472
Retained earnings	623,993	463,864
Accumulated other comprehensive income	1,566	—
Treasury stock, at cost, 1,042 shares and 6.7 million shares at December 31, 2007 and 2006, respectively	(57)	(298,445)
	3,338,247	1,130,683
	$ 9,693,351	$2,463,228

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per share data)

	Year Ended December 31,		
	2007	2006	2005
Revenues			
Oil sales	$1,116,376	$1,055,482	$ 873,121
Oil hedging	—	(145,755)	(139,089)
Gas sales			
Sales related to buy/sell contracts	—	—	36,940
Other	153,416	106,319	172,853
Gas hedging	—	—	(3,057)
Other operating revenues	3,048	2,457	3,652
	1,272,840	1,018,503	944,420
Costs and Expenses			
Production costs			
Lease operating expenses	225,845	179,741	140,595
Steam gas costs			
Costs related to buy/sell contracts	—	—	38,975
Other	103,464	63,811	39,302
Electricity	39,767	38,011	31,817
Production and ad valorem taxes	32,636	24,777	24,478
Gathering and transportation expenses	11,410	6,785	10,125
General and administrative	124,006	123,134	127,513
Depreciation, depletion and amortization	306,278	207,173	180,337
Accretion	9,800	9,609	7,578
Gain on sale of oil and gas properties	—	(982,988)	—
	853,206	(329,947)	600,720
Income from Operations	419,634	1,348,450	343,700
Other Income (Expense)			
Interest expense	(68,908)	(64,675)	(55,421)
Debt extinguishment costs	—	(45,063)	—
Loss on mark-to-market derivative contracts	(88,549)	(297,503)	(636,473)
Gain on termination of merger agreement	—	37,902	—
Interest and other income	6,322	5,496	3,324
Income (Loss) Before Income Taxes and Cumulative Effect of Accounting Change	268,499	984,607	(344,870)
Income tax (expense) benefit			
Current	4,677	(142,378)	229
Deferred	(114,425)	(242,519)	130,629
Income (Loss) Before Cumulative Effect of Accounting Change	158,751	599,710	(214,012)
Cumulative effect of accounting change (net of income tax benefit of $1,363)	—	(2,182)	—
Net Income (Loss)	$ 158,751	$ 597,528	$(214,012)
Earnings (loss) per share			
Basic			
Income (loss) before cumulative effect of accounting change	$ 2.02	$ 7.76	$ (2.75)
Cumulative effect of accounting change	—	(0.03)	—
Net income (loss)	$ 2.02	$ 7.73	$ (2.75)
Diluted			
Income (loss) before cumulative effect of accounting change	$ 1.99	$ 7.67	$ (2.75)
Cumulative effect of accounting change	—	(0.03)	—
Net income (loss)	$ 1.99	$ 7.64	$ (2.75)
Weighted Average Shares Outstanding			
Basic	78,627	77,273	77,726
Diluted	79,808	78,234	77,726

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands of dollars)

	Year Ended December 31, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 158,751	$ 597,528	$ (214,012)
Items not affecting cash flows from operating activities			
Gain on sale of oil and gas properties	—	(982,988)	—
Depreciation, depletion, amortization and accretion	316,078	216,782	187,915
Deferred income taxes	114,425	242,519	(130,629)
Noncash portion of debt extinguishment costs	—	9,289	—
Cumulative effect of adoption of accounting change	—	2,182	—
Commodity derivative contracts	88,549	443,258	620,564
Noncash compensation	43,697	37,766	55,271
Other noncash items	707	(268)	(93)
Change in assets and liabilities from operating activities, net of effect of acquisition			
Accounts receivable and other assets	(65,694)	29,739	(29,651)
Inventories	(530)	(1,277)	(1,762)
Accounts payable and other liabilities	53,351	(13,821)	(24,269)
Income taxes payable	(121,222)	94,272	—
Net cash provided by operating activities	588,112	674,981	463,334
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to oil and gas properties	(770,409)	(634,330)	(509,127)
Acquisition of Piceance Basin properties	(975,407)	—	—
Acquisition of Pogo Producing Company, net of cash acquired	(298,031)	—	—
Increase in restricted cash	(59,092)	—	—
Proceeds from sales of oil and gas properties, net of costs and expenses	—	1,550,663	346,450
Derivative settlements	(99,861)	(93,411)	—
Other, net	(40,337)	(10,923)	(5,743)
Net cash (used in) provided by investing activities	(2,243,137)	811,999	(168,420)
CASH FLOWS FROM FINANCING ACTIVITIES			
Revolving credit facilities			
Borrowings	4,745,100	1,618,900	1,504,200
Repayments	(2,775,600)	(1,655,400)	(1,342,200)
Proceeds from issuance of 7¾% Senior Notes	600,000	—	—
Proceeds from issuance of 7% Senior Notes	500,000	—	—
Redemption of long-term debt	(1,291,926)	(524,863)	—
Costs incurred in connection with financing arrangements	(47,333)	—	(1,600)
Derivative settlements	(3,688)	(621,862)	(459,450)
Purchase of treasury stock	(47,485)	(298,445)	—
Other	504	(5,963)	4,143
Net cash provided by (used in) financing activities	1,679,572	(1,487,633)	(294,907)
Net increase (decrease) in cash and cash equivalents	24,547	(653)	7
Cash and cash equivalents, beginning of period	899	1,552	1,545
Cash and cash equivalents, end of period	$ 25,446	$ 899	$ 1,552

See notes to consolidated financial statements.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands of dollars)

	Year Ended December 31,		
	2007	2006	2005
Net Income (Loss)	$158,751	$597,528	$(214,012)
Other Comprehensive Income			
Commodity hedging contracts			
Change in fair value	—	—	(82,942)
Reclassification adjustment for settled contracts	—	—	31,884
Reclassification adjustment for terminated contracts	—	145,755	106,165
Related tax expense	—	(56,189)	(20,799)
Pension			
Pension liability adjustment	2,522	—	—
Related tax expense	(956)	—	—
	1,566	89,566	34,308
Comprehensive Income (Loss)	$160,317	$687,094	$(179,704)

See notes to consolidated financial statements.

PLAINS EXPLORATION AND PRODUCTION COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(share and dollar amounts in thousands)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Treasury Stock		Total
	Shares	Amount				Shares	Amount	
Balance at December 31, 2004	77,179	$ 772	$ 913,466	$ 80,406	$(123,874)	(32)	$ (395)	$ 870,375
Net loss	—	—	—	(214,012)	—	—	—	(214,012)
Restricted stock awards	1,010	10	21,882	—	—	—	—	21,892
Treasury stock transactions	—	—	(337)	(58)	—	27	190	(205)
Other comprehensive income	—	—	—	—	34,308	—	—	34,308
Exercise of stock options and other	227	2	5,977	—	—	—	—	5,979
Balance at December 31, 2005	78,416	784	940,988	(133,664)	(89,566)	(5)	(205)	718,337
Net income	—	—	—	597,528	—	—	—	597,528
Restricted stock awards	696	7	22,551	—	—	—	—	22,558
Treasury stock transactions	—	—	—	—	—	(6,725)	(298,240)	(298,240)
Other comprehensive income	—	—	—	—	89,566	—	—	89,566
Exercise of stock options and other	60	1	933	—	—	—	—	934
Balance at December 31, 2006	79,172	792	964,472	463,864	—	(6,730)	(298,445)	1,130,683
Net income	—	—	—	158,751	—	—	—	158,751
Issuance of common stock in connection with property acquisition	1,000	10	44,530	—	—	—	—	44,540
Issuance of common stock in connection with acquisition of Pogo Producing Company	32,308	323	1,649,320	—	—	7,755	345,873	1,995,516
Restricted stock awards	357	3	53,234	—	—	—	—	53,237
Treasury stock transactions	—	—	—	—	—	(1,026)	(47,485)	(47,485)
Cumulative effect of accounting change (Note 9)	—	—	—	1,378	—	—	—	1,378
Other comprehensive income	—	—	—	—	1,566	—	—	1,566
Exercise of stock options and other	4	—	61	—	—	—	—	61
Balance at December 31, 2007	112,841	$1,128	$2,711,617	$ 623,993	$ 1,566	(1)	$ (57)	$3,338,247

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, a Delaware corporation, ("PXP", "us", "our", or "we") include the accounts of all its wholly owned subsidiaries. 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, develops, explores for and produces oil and gas. Our upstream activities are primarily located in the United States. We also have interests in exploration prospects offshore New Zealand and Vietnam.

Significant Accounting Policies

Oil and Gas Properties. We follow the full cost method of accounting whereby all costs associated with property acquisition, exploration 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 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 estimated asset retirement obligations recorded in accordance with Statement of Financial Accounting Standards ("SFAS") No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"), 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 cause a significant change in the relationship between costs and the estimated value of proved reserves, in which case a gain or loss is recognized. Capitalized costs of proved oil and gas properties (net of accumulated depreciation, depletion and amortization and deferred income taxes) are subject to a ceiling, on a country-by-country basis, 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, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to SFAS 143 and estimated future income taxes thereon.

Asset Retirement Obligation. We account for our asset retirement obligation in accordance with SFAS 143 which requires entities to record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred. A legal obligation is a liability that a party is required to settle as a result of an existing or enacted law, statute, ordinance or contract. When the liability is initially recorded, the entity is required to capitalize the retirement cost 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, the difference is recognized in Oil and Gas Properties.

Other Property and Equipment. Other property and equipment is recorded at cost and consists primarily of aircraft, office furniture and fixtures, computer hardware and software, land and real estate development costs. 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 twenty years. Net gains or losses on property and equipment disposed of are included in operating 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) assigning fair value and allocating purchase price in connection with business combinations, including goodwill; (4) income taxes; (5) accrued assets and liabilities; (6) stock based compensation; (7) asset retirement obligations and (8) valuation of derivative instruments. 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. The majority of cash and cash equivalents was concentrated in three institutions at December 31, 2007 and one institution at December 31, 2006 and at times may exceed federally insured limits. We periodically assess the financial condition of the institutions and believe that any possible credit risk is minimal. Accounts payable at December 31, 2007 and 2006 includes $5.8 million and $5.3 million, respectively, representing outstanding checks that had not been presented for payment.

Restricted Cash. Restricted cash consists of certain amounts payable to former Pogo executives. The amounts are held in trust and subject to the claims of the Company's creditors in the event of the Company's insolvency until paid to the beneficiaries.

Inventory. Oil inventories are carried at the lower of the cost to produce or market value and materials and supplies inventories are 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,	
	2007	2006
Oil	$ 6,066	$ 4,954
Materials and supplies	12,328	7,440
	$18,394	$12,394

Federal and State Income Taxes. Income taxes are accounted for in accordance with SFAS 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.

Effective January 1, 2007, we adopted Financial Accounting Standards Board ("FASB") Interpretation No. 48 "Accounting for Uncertainty in Income Taxes (an interpretation of FASB Statement No. 109)" ("FIN 48"). This interpretation clarified the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. See Note 9.

Revenue Recognition. Oil and gas revenue from our interests in producing wells is recognized when the production is delivered and the title transfers. The Company follows the sales method of accounting for gas imbalances. If the Company's excess sales of production volumes for a well exceed the estimated remaining recoverable reserves of the well, a liability is recorded. No receivables are recorded for those wells on which the Company has taken less than its ownership share of production.

Derivative Financial Instruments. We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. At December 31, 2007, our derivative instruments consisted of crude oil put option contracts and collars and natural gas collars entered into with financial institutions. We do not enter into derivative instruments for speculative trading purposes. Derivative instruments are accounted for in accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities", as amended ("SFAS 133"). The Company presents the fair value of its derivatives on a net basis in accordance with FASB Interpretation No. 39 "Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105" ("FIN 39"). See Note 4.

Goodwill. In a purchase transaction, goodwill represents the excess of the purchase price plus the liabilities assumed, including deferred income taxes recorded in connection with the transaction, over the fair value of the net assets acquired. Goodwill is not amortized, but instead must be tested at least annually for impairment by applying a fair-value based test. Goodwill is deemed impaired to the extent of any excess of its carrying amount over the residual fair value of the reporting unit. Such impairment could significantly reduce earnings during the period in which the impairment occurs and would result in a corresponding reduction to goodwill and stockholders' equity. The most significant factors that could result in the impairment of our goodwill would be significant declines in oil and gas prices and/or estimated reserve volumes which would result in a decline in the fair value of our oil and gas properties. We follow the full cost method of accounting. All of our producing properties are located in the United States, and our international operations consist primarily of unevaluated properties with no associated goodwill. We have determined that for the purpose of performing an impairment test, we have one reporting unit. We perform our goodwill impairment test annually on December 31 and have recorded no impairments to goodwill based on such tests.

In 2007, we recorded $383.7 million of goodwill in connection with our acquisition of Pogo Producing Company. In 2007 and 2006, goodwill decreased by $4.6 million and $15.3 million, respectively, as a result of a change in the tax basis related to our acquisition of Nuevo Energy Company.

Business Segment Information. SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information" ("SFAS 131") establishes standards for reporting information about operating segments. We acquire, develop, explore for and produce oil and gas primarily in the United States. Our corporate management team administers all properties as a whole rather than as discrete operating segments. We allocate capital resources on a project-by-project basis across our entire asset base to maximize profitability and measure financial performance as a single enterprise and not on an area-by-area basis. Accordingly, we have one operating segment, our oil and gas operations. Our international activities currently consist of exploration prospects in offshore New Zealand and Vietnam that were obtained in our acquisition of Pogo in November 2007 that have no proved reserves, oil and gas production or sales. Capitalized costs consisted of $15.7 million of costs not subject to amortization as of December 31, 2007. Accordingly, no geographic data is presented for our international operations.

Stock Based Compensation. Beginning in 2006, our stock based compensation is accounted for under SFAS No. 123R, "Share-Based Payment" ("SFAS 123R"), which requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements. That cost is measured based on the fair value of the equity and liability awards issued. See Note 7. In 2005 and prior periods we accounted for stock based compensation using the intrinsic value method pursuant to Accounting Principles Bulletin No. 25 "Accounting for Stock Issued to Employees" ("APB 25"). No adjustments to our net income or earnings per share would have been required under SFAS No. 123 "Accounting for Stock Based Compensation" ("SFAS 123") because we recognized the same amount of compensation expense for our stock appreciation rights ("SARs") and restricted stock units ("RSUs") under APB 25 and we did not issue stock options.

Pension and Other Post-Retirement Benefits. As a result of our acquisition of Pogo, we recorded assets and liabilities for a defined benefit pension plan and other post-retirement benefits. We account for the pension plan under SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an Amendment of FASB Statements No. 87, 88, 106 and 132(R)" ("SFAS 158"). Under SFAS No. 158, we record an asset or liability for pension and other postretirement benefit plans based on their overfunded or underfunded status. Any deferred amounts related to unrealized gains and losses or changes in actuarial assumptions are recorded in accumulated other comprehensive income (loss), a component of stockholders' equity, until those gains and losses are recognized in the income statement. See Note 8.

Buy/Sell Contracts. Steam generators utilized in our thermal recovery operations in California are fueled by natural gas. In certain instances we have entered into buy/sell contracts that allow us to exchange gas we produce elsewhere for gas delivered to and used in thermal recovery operations. Effective January 1, 2006, we adopted Emerging Issues Task Force Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF 04-13 requires that two or more inventory transactions with the same counterparty be viewed as a single non-monetary transaction if the transactions were entered into in contemplation of one another (as determined in accordance with EITF 04-13). We have determined that transactions under certain of our buy/sell contracts should be presented net in accordance with EITF 04-13. Accordingly, certain costs previously recorded gross in revenues and operating costs in prior periods are recorded net in 2006 and subsequent periods.

Recent Accounting Pronouncements. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" which is effective for fiscal years beginning after November 15, 2007 and for interim periods within those years. This statement defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities –Including an Amendment of FASB Statement No. 115", which is effective for fiscal years beginning after November 15, 2007. This statement permits an entity to choose to measure many financial instruments and certain other items at fair value at specified election dates. Subsequent unrealized gains and losses on items for which the fair value option has been elected will be reported in earnings. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, "Amendment of FASB Interpretation No. 39" ("FSP FIN 39-1"), which amended FIN 39, to indicate that the following fair value amounts could be offset against each other if certain conditions of FIN 39 are otherwise met: (a) those recognized for derivative instruments executed with the same counterparty under a master netting arrangement and (b) those recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from the same master netting arrangement as the derivative instruments. In addition, a reporting entity is not precluded from offsetting the derivative instruments if it determines that the amount recognized upon payment or receipt of cash collateral is not a fair value amount. FSP FIN 39-1 is effective at the beginning of the first fiscal year after November 15, 2007. We do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51" ("SFAS 160"). SFAS 160 requires companies with noncontrolling interests to disclose such interests clearly as a portion of equity but separate from the parent's equity. The noncontrolling interest's portion of net income must also be clearly presented on the Income Statement. SFAS 160 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and we do not expect this pronouncement to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* ("SFAS 141R"). SFAS 141R broadens the guidance of SFAS 141, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. It broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations. SFAS 141R expands on required disclosures to improve the statement users' abilities to evaluate the nature and financial effects of business combinations. SFAS 141R is effective for fiscal year beginning on or after December 15, 2008. We are currently evaluating the potential impact of this statement on future business combinations.

Note 2—Acquisitions

Pogo Producing Company

On November 6, 2007, we acquired Pogo in a stock and cash transaction (the "Pogo acquisition"). We paid cash consideration of approximately $1.5 billion and issued approximately 40 million common shares valued at approximately $2.0 billion. In addition, we paid cash consideration of $35.4 million to redeem outstanding stock options. The total purchase price includes $154.2 million of merger costs. These costs include Pogo executive management and employee severance, investment banking fees, legal and accounting fees, seismic transfer fees, printing expenses and other merger-related costs. The cash portion of the purchase price was funded by borrowings under our revolving credit facility.

The acquisition was accounted for under the purchase method of accounting and Pogo's results of operations were included in our consolidated statement of income effective November 6, 2007. The assets and liabilities of Pogo were recorded at their fair values. The calculation of the purchase price and the allocation to assets and liabilities as of November 6, 2007 is shown below. The average PXP common stock price is based on the average closing price of PXP common stock during the five business days commencing two days before the merger was announced. The purchase price allocation is preliminary subject to our determination of Pogo's final tax basis, asset retirement obligations and fair value of the assets and liabilities that have not been completed as of December 31, 2007. These and other estimates are subject to change as additional information becomes available and is assessed by us.

	(thousands except shares and share price)
Shares of PXP common stock issued	40,062,560
Average PXP stock price	$ 49.81
Fair value of PXP common stock to be issued	$ 1,995,516
Cash payment to stockholders	1,461,604
Cash payment to option holders	35,382
Merger expenses	154,157
Total estimated purchase price before liabilities assumed	3,646,659
Fair value of liabilities:	
Current liabilities	255,461
Long-term debt	1,291,977
Asset retirement obligation	51,976
Deferred income tax liabilities, net	1,224,183
Other noncurrent liabilities	35,287
Total estimated purchase price plus liabilities assumed	$ 6,505,543
Fair value of assets acquired:	
Cash and cash equivalents	$ 1,276,695
Other current assets	147,654
Oil and gas properties	
Subject to amortization	3,361,710
Not subject to amortization	1,333,130
Other non-current assets	2,625
Goodwill	383,729
Total assets	$ 6,505,543

The significant factors contributing to the recognition of goodwill included, but are not limited to, providing the Company with greater financial flexibility with access to lower cost of capital and higher returns from cost synergies, having increased opportunities from a broader and more diversified reserve base and the ability to acquire an established business with an assembled workforce. In addition, we recorded goodwill due to the application of purchase accounting rules that require deferred taxes be recorded at undiscounted amounts. Goodwill is not deductible for income tax purposes.

Certain of the amounts payable to former Pogo executives upon the change of control were placed in a rabbi trust established to provide for the payments and benefits owed to such executives. The assets will be held in trust subject to the claims of the Company's creditors in the event of the Company's insolvency until paid to the beneficiaries as specified in the respective executive employment agreements. At December 31, 2007, the $59.1 million balance in the rabbi trust was invested in a money market account that is a direct liability of the financial institution, which is highly rated by the major credit rating agencies. In addition, the account is collateralized on a dollar for dollar basis. Acceptable collateral is generally U.S. Treasury, Government and agency securities and other highly rated investments. This amount is included in restricted cash in the consolidated balance sheet with a corresponding amount of deferred compensation included in current liabilities. The deferred compensation is required to be paid to the beneficiaries in April 2008.

Piceance Basin Properties

On May 31, 2007, we acquired certain properties located in the Piceance Basin (the "Piceance acquisition") for $975 million in cash, including $10 million in related acquisition costs and $65 million for net cash outflows from the effective date to the closing date (primarily related to capital expenditures for drilling and acreage acquisitions) and issued one million shares of common stock with a fair value of approximately $45 million to the seller. The Piceance acquisition includes interests in oil and gas producing properties in the Mesaverde geologic section of the Piceance Basin in Colorado, plus associated midstream assets, including a 25% interest in Collbran Valley Gas Gathering LLC ("CVGG"). We allocated the purchase price as follows: $518 million to oil and gas properties subject to amortization, $448 million to oil and gas properties not subject to amortization, $40 million to our investment in CVGG and the remainder to inventory and other properties and equipment. We financed the acquisition using our senior revolving credit facility.

Unaudited Pro Forma Information

The following unaudited pro forma information shows the pro forma effect of the Pogo acquisition, the Piceance acquisition, the issuance by PXP of $500 million of 7% Senior Notes due 2017, the issuance by PXP of $600 million of 7.75% Senior Notes due 2015, $2.0 billion of borrowings under the revolving credit facility, and the retirement of Pogo's $450 million 7.875% Senior Notes due 2013, $300 million 6.625% Senior Notes due 2015, and $500 million 6.875% Senior Notes. We believe the assumptions used provide a reasonable basis for presenting the pro forma significant effects directly attributable to the Pogo and Piceance Basin properties acquisitions. This unaudited pro forma information assumes such transactions occurred on January 1 of the years presented. This pro forma financial information does not purport to represent what our results of operations would have been if such transactions had occurred on such dates.

	Year Ended December 31,	
	2007	2006
	(thousands except per share data) (unaudited)	
Revenues	$2,022,599	$1,664,017
Income from operations	396,841	1,397,500
Income from continuing operations	74,422	702,118
Net income	74,422	702,118
Basic and diluted earnings per share		
Basic		
Income from continuing operations	$ 0.66	$ 5.94
Net income	0.66	5.94
Diluted		
Income from continuing operations	$ 0.65	5.89
Net income	0.65	5.89
Weighted average shares outstanding		
Basic	113,066	118,273
Diluted	114,247	119,234

Pro forma results for 2006 include the $983.0 million gain on the sale of oil and gas properties, the $45.1 million charge for debt extinguishment and the $37.9 million gain on termination of merger agreement.

Note 3—Divestments

On December 14, 2007, we, together with certain of our subsidiaries, entered into a definitive purchase and sale agreement with a subsidiary of Occidental Petroleum Corporation (“Oxy”) to sell 50% of our interests in oil and gas properties located in the Permian Basin, West Texas and New Mexico, Piceance Basin in Colorado (including a 50% interest in the entity which holds our interest in CVGG) and the Utah Overthrust exploratory prospect for $1.55 billion in cash. We will retain 50% of our interest in the Permian and Piceance Basin properties. The transaction effective date is January 1, 2008 and is expected to close during the first quarter of 2008, subject to customary closing conditions and adjustments.

On December 14, 2007, certain of our subsidiaries entered into a definitive purchase and sale agreement with XTO Energy Inc. to sell our oil and gas interests located in the San Juan Basin in New Mexico and in the Barnett Shale in Texas. The sale of the San Juan Basin and Barnett Shale properties closed on February 15, 2008, with an effective date of January 1, 2008, and we received $199 million of cash. We are scheduled to purchase XTO's 50% working interest in the Big Mac prospect area located on the Texas Gulf Coast for approximately $20 million during the first quarter of 2008. Subsequent to closing the transaction, we will have a 100% working interest in the Big Mac prospect area, covering approximately 50,000 net lease acres.

Proved reserves attributed to the asset divestments expected to close in the first quarter of 2008 were 112.8 MMBOE at December 31, 2007.

On November 1, 2006, we closed the sale of non-producing oil and gas properties to Statoil Gulf of Mexico LLC. The Company received approximately $706 million in cash proceeds and recognized a pre-tax gain of $638 million because the sale caused a significant change in the relationship between capitalized costs and proved reserves. With respect to the sale of properties to Statoil, capitalized costs consist of the costs of the prospects that were classified as costs not subject to amortization.

On September 29, 2006, we closed the sale of oil and gas properties located primarily in California and Texas to subsidiaries of Oxy. This transaction had an effective date of October 1, 2006. We received approximately $864 million in cash proceeds and recognized a $345 million pre-tax gain because the sale resulted in a significant change in the relationship between capitalized costs and proved reserves.

We follow the full cost method of accounting under which proceeds from the sale of oil and gas properties are accounted for as reductions to capitalized costs unless such sales result in a significant change in the relationship between capitalized costs and proved reserves, in which case a gain or loss is recognized. When a gain or loss is recognized, total capitalized costs within the cost center are allocated between the reserves sold and the reserves retained on the same basis used to compute amortization unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs are allocated on the basis of the relative fair values of the properties. With respect to the September 29, 2006 sale of properties to Oxy, capitalized costs were allocated on the basis of the relative fair values of the properties. A portion of the gain was allocated to certain of our subsidiaries based on the relative reserve volumes sold. See Note 17.

Note 4—Derivative Instruments and Hedging Activities

General

We use various derivative instruments to manage our exposure to commodity price risk on sales of oil and gas production. All derivative instruments are recorded on the balance sheet at fair value. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recognized currently in our income statement as a gain or loss on mark-to-market derivative contracts. Cash flows are only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. We do not currently use hedge accounting for our derivative instruments. If a derivative is designated as a cash flow hedge and qualifies for hedge accounting, any unrealized gain or loss is deferred in Accumulated Other Comprehensive Income ("OCI"), a component of Stockholders' Equity, until the hedged oil and gas production is sold. Realized gains and losses on derivative instruments that are designated as a hedge and qualify for hedge accounting are generally included in oil and gas revenues in the period the hedged volumes are sold. Gains and losses deferred in OCI related to cash flow hedges for which hedge accounting has been discontinued remain in OCI until the related product has been delivered.

Under SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", certain of our derivatives are deemed to contain a significant financing element because they included off-market terms and cash settlements with respect to such derivatives are required to be reflected as financing activities in the Statement of Cash Flows. Cash settlements with respect to derivatives that are qualified for hedge accounting and do not have a significant financing element are reflected as operating activities in the Statement of Cash Flows. Cash settlements with respect to derivatives that are not qualified for hedge accounting and do not have a significant financing element are reflected as investing activities in the Statement of Cash Flows.

At December 31, 2007, we had the following open commodity derivative positions, none of which were designated as hedging instruments:

Period	Instrument Type	Daily Volumes	Average Price	Index
Sales of Crude Oil Production				
2008				
Jan - Dec	Put options	42,000 Bbls	$55.00 Strike price	WTI
Jan - Dec	Collar	2,500 Bbls	$60.00 Floor—$80.13 Ceiling	WTI
2009				
Jan - Dec	Put options	32,500 Bbls	$55.00 Strike price	WTI
Sales of Natural Gas Production				
2008				
Jan - Dec	Collar	15,000 MMBtu	$8.00 Floor—$12.11 Ceiling	Henry Hub

The average strike price for the put options and call options does not reflect the cost to purchase such options. The only cash settlements we are required to make on the purchased put options are option premiums and interest, which are expected to total approximately $58 million in 2008 and $40 million in 2009.

Elimination of 2006, 2007 and 2008 Swap and Collar Positions

During 2006, we paid $593.3 million to eliminate all of our 2007 and 2008 crude oil collars for 22,000 barrels of oil per day for all of 2007 and 2008 with a floor price of $25.00 and an average ceiling price of $34.76. Approximately $170 million of mark-to-market losses related to the collars was recognized in our income statement in 2006 and $423 million in prior periods.

During 2005, we completed a series of transactions that eliminated all of our 2006 crude oil price swaps and collars at a pre-tax cost of $292.7 million. Approximately $145.4 million of this amount was attributable to 2006 collars for 22,000 barrels of oil per day with a floor price of $25.00 and an average ceiling price of $34.76. The collars were not accounted for as hedges, therefore, the $145.4 million loss in the fair value of these instruments was recognized in our income statement in 2005 and 2004 and there was no income statement effect in 2006. Approximately $147.3 million of the cost was attributable to 2006 swaps for 15,000 barrels of oil per day at an average price of $25.28. We used hedge accounting through March 2005 for the swaps and as a result the $145.8 million loss in fair value attributable to the swaps was deferred in OCI and recognized as a noncash reduction to oil revenues in 2006 when the hedged production was sold.

Income Statement, Cash Payments and Other Comprehensive Income

During the years ended December 31, 2007, 2006 and 2005, pre-tax amounts recognized in our income statement for derivatives were as follows (in thousands of dollars):

	Year Ended December 31,		
	2007	2006	2005
Loss on mark-to-market derivative contracts	$(88,549)	$(297,503)	$(636,473)
Gain (loss) reclassified from OCI and recognized in:			
Oil revenues (1)	—	(145,755)	(139,089)
Gas revenues	—	—	(3,057)
Steam gas costs	—	—	4,097

(1) Includes $0.1 million in 2005 for hedge ineffectiveness.

During the years ended December 31, 2007, 2006 and 2005, cash payments for derivatives were as follows (in thousands of dollars):

	Year Ended December 31,		
	2007	2006	2005
Contracts accounted for using hedge accounting			
Oil sales	$ —	$ —	$ (53,044)
Gas sales	—	—	(6,255)
Gas purchases	—	—	10,293
Elimination of crude oil swaps	—	—	(147,280)
Mark-to-market contracts			
Oil sales	(103,784)	(89,596)	(279,982)
Gas sales	235	—	—
Gas purchases	—	(11,425)	—
Elimination of crude oil collars	—	(593,283)	(145,383)

At December 31, 2007 and 2006, there were no amounts related to derivative transactions in OCI. At December 31, 2005, OCI consisted of $145.8 million ($89.6 million, net of tax) of deferred losses attributable to the cancelled 2006 swaps that were reclassified to oil and gas revenue in 2006.

Note 5—Asset Retirement Obligation

The following table reflects the changes in our asset retirement obligation during the years ended December 31, 2007, 2006 and 2005 (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Asset retirement obligation—beginning of period	$137,311	$160,955	$130,469
Liabilities incurred in acquisitions	54,349	—	12,613
Property dispositions and other	—	(30,506)	(2,848)
Settlements	(2,396)	(2,886)	(1,735)
Change in estimate	(6,900)	(3,134)	11,443
Accretion expense	9,800	9,609	7,541
Asset retirement additions	3,244	3,273	3,472
Asset retirement obligation—end of period (1)	$195,408	$137,311	$160,955

(1) $11.3 million and $3.9 million included in other current liabilities at December 31, 2007 and 2006, respectively.

Note 6—Long-Term Debt

At December 31, 2007 and 2006, long-term debt consisted of (in thousands):

	December 31,	
	2007	2006
Senior revolving credit facility	$2,205,000	$235,500
7¾% senior notes	600,000	—
7% senior notes	500,000	—
	$3,305,000	$235,500

Aggregate total maturities of long-term debt in the next five years are $2.2 billion in 2012.

Senior Revolving Credit Facility. On November 6, 2007, we entered into an Amended and Restated Credit Agreement (the "Amended Credit Agreement"), which amends and restates PXP's five-year senior revolving credit facility, which closed May 31, 2007. The Amended Credit Agreement provides for an initial borrowing base of $2.9 billion and a conforming borrowing base of $2.6 billion, which will be redetermined on an annual basis, with PXP and the lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on PXP's oil and gas properties, reserves, other indebtedness and other relevant factors. The borrowing base will be automatically reduced to equal the conforming borrowing base on the earlier of (a) the first anniversary of the closing of the Pogo acquisition, (b) the first date on which PXP issues additional senior notes permitted by the Amended Credit Agreement and (c) the sale (in one or more transactions) of oil and gas properties not covered by the most recently delivered reserve report and the issuance of equity interests for an aggregate consideration of $300 million or more. Additionally, the Amended Credit Agreement contains a $250 million sub-limit on letters of credit, a $50 million commitment for swingline loans, and matures on November 6, 2012. Collateral consists of 100% of the shares of stock in certain of our domestic and 65% of certain foreign subsidiaries and mortgages covering at least 75% of the total present value of our domestic oil and gas properties.

Amounts borrowed under the Amended Credit Agreement bear an annual interest rate, at our election, equal to either: (i) the Eurodollar rate, which is based on LIBOR, plus an additional variable amount ranging from 1.00% to 2.00%; (ii) the greater of (1) the prime rate, as determined by JPMorgan Chase Bank and (2) the federal funds rate, plus ½ of 1%, plus an additional variable amount ranging from 0% to .5% for each of (1) and (2); and (iii) the over-night federal funds rate plus an additional variable amount ranging from 1.00% to 2.00% for swingline loans. The additional variable 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 Amended Credit Agreement to the conforming borrowing base and (2) our long-term debt ratings. Commitment fees and letter of credit fees under the Amended Credit Agreement are based on the utilization rate and our long-term debt rating. Commitment fees range from .225% to .375% of the amount available for borrowing. Letter of credit fees range from 1.0% to 2.0%. The issuer of any letter of credit receives an issuing fee of .125% of the undrawn amount. The effective interest rate on our borrowings under the Amended Credit Agreement was 6.5% at December 31, 2007.

The Amended Credit Agreement contains negative covenants that limit our ability, as well as the ability of our restricted 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, guarantee other indebtedness, enter into agreements that restrict dividends from subsidiaries, enter into certain types of swap agreements, enter into take-or-pay or other prepayment arrangements, merge or consolidate and enter into transactions with affiliates. In addition, we are required to maintain a ratio of debt to EBITDAX (as defined) of no greater than 4.25 to 1.

At December 31, 2007, we had $7.7 million in letters of credit outstanding under the Amended Credit Agreement. At that date we were in compliance with the covenants contained in the Amended Credit Agreement and could have borrowed the full amount available under the Amended Credit Agreement.

Short-term Credit Facility. We may make borrowings from time to time until May 1, 2008, not to exceed at any time the maximum principal amount of $50 million. No advance under the short-term facility may have a term exceeding fourteen days and all amounts outstanding are due and payable no later than May 1, 2008. Each advance under the short-term facility shall bear interest at a rate per annum mutually agreed on by the bank and the Company. No amounts were outstanding under the short-term credit facility at December 31, 2007.

7¾% Senior Notes. In June 2007, we issued $600 million of 7¾% Senior Notes due 2015 (the "7¾% Senior Notes") at par. The net proceeds were used to repay borrowings under our senior revolving credit facility. We may redeem all or part of the 7¾% Senior Notes on or after June 15, 2011 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to June 15, 2010 we may, at our option, redeem up to 35% of the 7¾% Senior Notes with the proceeds from certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7¾% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

7% Senior Notes. In March 2007, we issued $500 million of 7% Senior Notes due 2017 (the "7% Senior Notes") at par. The net proceeds were used to repay borrowings under our senior revolving credit facility and for general corporate purposes. We may redeem all or part of the 7% Senior Notes on or after March 15, 2012 at specified redemption prices and prior to such date at a "make-whole" redemption price. In addition, prior to March 15, 2010 we may, at our option, redeem up to 35% of the 7% Senior Notes with the proceeds from certain equity offerings. In the event of a change of control, as defined in the indenture, we will be required to make an offer to repurchase the 7% Senior Notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of the repurchase.

The 7% Senior Notes and 7¾% Senior Notes are our general unsecured senior obligations. The 7% Senior Notes and 7¾% Senior Notes are jointly and severally guaranteed on a senior unsecured basis by certain of our existing domestic subsidiaries. In the future, the guarantees may be released or terminated under certain circumstances. The 7% Senior Notes and 7¾% Senior Notes rank senior in right of payment to all of our existing and future subordinated indebtedness; *pari passu* in right of payment with any of our existing and future unsecured indebtedness that is not by its terms subordinated to the 7% Senior Notes and 7¾% Senior Notes; effectively junior to our existing and future secured indebtedness, including indebtedness under our senior revolving credit facility, to the extent of our assets constituting collateral securing that indebtedness; and effectively subordinate to all existing and future indebtedness and other liabilities (other than indebtedness and liabilities owed to us) of our non-guarantor subsidiaries.

The indentures governing the 7% Senior Notes and 7¾% Senior Notes contain covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company. At December 31, 2007, we were in compliance with the covenants contained in the indentures for the 7% Senior Notes and the 7¾% Senior Notes.

7.125% Senior Notes. On November 3, 2006, we made payments totaling $268.6 million to retire all $250 million outstanding principal amount of our 7.125% Senior Notes due 2014. The redemption price of $1,074.50 per $1,000 principal amount was based on a “make-whole” calculation tied to a comparable United States Treasury security.

8.75% Senior Subordinated Notes. On November 3, 2006, we made payments totaling $291.9 million to retire $274.9 million of the $275 million outstanding principal amount of our 8.75% Senior Subordinated Notes due 2012 (the "Senior Subordinated Notes"). In October 2007, we made the final payment to retire the remaining $0.1 million principal amount.

Debt Extinguishment Costs. In connection with the retirement of the 7.125% Senior Notes due 2014 and the 8.75% Senior Subordinated Notes due 2012, we recorded $45.1 million of debt extinguishment costs in our 2006 consolidated income statement.

Pogo Tender Offers and Consent Solicitations for Senior Subordinated Notes of Pogo Producing Company LLC. Prior to the acquisition by PXP, Pogo initiated a tender offer of 104% for the $450 million of its outstanding 7.875% Senior Subordinated Notes due 2013 (the “7.875% Senior Subordinated Notes”), of 103% for the $300 million of its outstanding 6.625% Senior Subordinated Notes due 2015 (the “6.625% Senior Subordinated Notes”) and of 103% for the $500 million of its outstanding 6.875% Senior Subordinated Notes due 2017 (the “6.875% Senior Subordinated Notes”). In November and December 2007, we completed the redemption of all $450 million of outstanding 7.875% Senior Subordinated Notes, over 99% of all $500 million of outstanding 6.875% Senior Subordinated Notes and all $300 million of outstanding 6.625% Senior Subordinated Notes. The Notes were redeemed for approximately $1.3 billion, which included the tender offer purchase price and consent payments of $42.0 million plus accrued interest to November 19, 2007 of $10.4 million. The cash redemption payment was funded using available cash on hand. The remaining $0.1 million of the 6.875% Senior Subordinated Notes principal outstanding is redeemable at any time under a “make-whole” payment provision, and is included in Other Current Liabilities in the December 31, 2007 Consolidated Balance Sheet.

Subsequent Event. On February 13, 2008, we entered into an amendment to the Amended Credit Agreement. The amendment reduces the borrowing base and commitments to $2.8 billion from $2.9 billion upon the closing of the sale of certain properties to XTO. The borrowing base and commitments will be further reduced to $2.5 billion and $1.9 billion, respectively, upon the closing of the sale of certain properties to Oxy. In addition, the amendment allows us to repurchase up to $1.0 billion of our common stock upon the closing of the XTO and Oxy sales subject to certain conditions being met.

Note 7—Stock Based and Other Compensation Plans

Prior to January 1, 2006, we accounted for stock based compensation using the intrinsic value method pursuant to APB 25. Effective January 1, 2006, we adopted the provisions of SFAS 123R. Under the provisions of SFAS 123R, stock-based compensation is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the requisite employee service period (generally the vesting period of the grant). We adopted SFAS 123R using the modified prospective application method, under which compensation cost is recognized in the financial statements beginning with the adoption date for all share-based payments granted after that date, and for all unvested awards granted prior to the adoption of SFAS 123R. The cumulative adjustment at January 1, 2006 associated with the adoption of SFAS 123R was a $2.2 million charge to earnings (net of a $1.4 million tax benefit). Our paid-in capital was increased by $3.6 million and our deferred tax liability was decreased by $1.4 million.

We have three stock incentive plans, the 2002 Stock Incentive Plan (the “2002 Plan”), which provides for a maximum of 1.5 million shares available for awards, the 2004 Stock Incentive Plan (the

"2004 Plan"), which provides for a maximum of 8.4 million shares available for awards, and the 2006 Incentive Plan (the "2006 Incentive Plan"), which provides for a maximum of 1.0 million shares available for awards. The 2002 Plan and the 2004 Plan provide for the grant of stock options, and other awards (including performance units, performance shares, share awards, restricted stock, RSUs and SARs), to our directors, officers, employees, consultants and advisors. Our 2006 Plan provides for the grant of cash-only SARs and RSUs to non-officer employees. Our compensation committee may grant options and SARs on such terms, including vesting and payment forms, as it deems appropriate in its discretion, however, no option or SAR may be exercised more than 10 years after its grant date, and the purchase price for incentive stock options and non-qualified stock options may not be less than 100% of the fair market value of our common stock on the date of grant. The compensation committee may grant restricted stock awards, RSUs, share awards, performance units and performance shares on such terms and conditions as it may decide in its discretion.

Upon an event constituting a "change in control" (as defined in the plans) of PXP, all options and SARs will become immediately exercisable in full. In addition, in such an event, unless otherwise determined by our organization and compensation committee, all other awards will vest and all restrictions on such awards will lapse. The Company may, at its discretion, issue new shares or use treasury shares to satisfy vesting requirements.

Stock based compensation for the years ended December 31, 2007, 2006 and 2005 was (in thousands):

	Year Ended December 31,		
	2007 (1)	**2006 (1)**	**2005 (2)**
Stock-based compensation included in:			
General and administrative expense	$48,123	$52,196	$77,192
Lease operating expenses	3,896	3,289	579
Oil and natural gas properties under full cost method	11,010	8,378	3,082
Total stock-based compensation	$63,029	$63,863	$80,853

(1) In accordance with SFAS 123R.
(2) In accordance with APB 25.

Stock based compensation charged to earnings for the years ended December 31, 2007, 2006 and 2005 was (in thousands):

	Year Ended December 31,		
	2007 (1)	**2006 (1)**	**2005 (2)**
Charged to earnings	$ 52,019	$ 55,485	$ 77,771
Tax benefit	(19,728)	(22,111)	(30,066)
	$ 32,291	$ 33,374	$ 47,705

(1) In accordance with SFAS 123R.
(2) In accordance with APB 25.

At December 31, 2007, there is $179.0 million of total unrecognized compensation cost related to unvested share-based compensation arrangements that is expected to be recognized over a weighted-average period of approximately 3.9 years. Stock based compensation for the year ended

December 31, 2006 includes $8.4 million resulting from the accelerated vesting of 0.5 million RSUs. Stock based compensation expense for the year ended December 31, 2005 includes $18.8 million resulting from the accelerated vesting of 1.3 million RSUs because certain stock price targets were met.

Estimates of fair value are not intended to predict actual future events or the value ultimately realized by employees who receive share-based awards, and subsequent events are not indicative of the reasonableness of original estimates of fair value made by the Company under SFAS 123R.

SARs

SAR grants generally vest ratably over three years or 100% after three years and expire within five to ten years after the date of grant. These awards are similar to stock options, but are settled in cash rather than in shares of common stock and are classified as liability awards. Under the provisions of SFAS 123R, compensation cost for these awards is determined using a fair-value method and remeasured at each reporting date until the date of settlement. Stock-based compensation expense recognized in the years ended December 31, 2007 and 2006 is based on the number of SARs ultimately expected to vest and has been reduced for estimated forfeitures.

The following table summarizes the status of our SARs at December 31, 2007 and the changes during the year then ended:

	Outstanding (thousands)	Weighted Average Exercise Price	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (Years)
Outstanding at January 1, 2007	2,224	$20.22		
Granted	906	48.48		
Exercised	(260)	17.37		
Forfeited or expired	(103)	41.32		
Outstanding at December 31, 2007	2,767	28.90	$69,472	3.3
Exercisable at December 31, 2007	1,395	13.06	$57,135	2.9

The total intrinsic value of SARs exercised in the years ended December 31, 2007, 2006 and 2005 was $8.3 million, $17.7 million and $22.5 million, respectively, and the per share fair value as of December 31, 2007 and 2006 for SARs granted in each of the years then ended was $17.32 and $17.03, respectively. The weighted average grant date fair value per share for SARs granted in 2007 and 2006 was $12.42 and $10.45, respectively.

We estimate the fair value of SARs granted using the Black-Scholes valuation model and the fair value of the SARs is remeasured at the end of each period. The following assumptions are as of December 31, 2007 and 2006:

	2007	2006
Expected life (in years)	1-4	1-4
Volatility	27.6% - 30.8%	26.8% - 37.3%
Risk-free interest rate	3.1% - 3.5%	4.7% - 5.0%
Dividend yield	0%	0%

Expected volatility is based on the historical volatility of our common stock and other factors. We use historical experience with exercise and post-vesting exercise behavior to determine the SARs expected life. The expected life represents the period of time that SARs granted are expected to be outstanding. The risk-free interest rate is based on the U.S. Treasury rate with a maturity date corresponding to the SARs' expected life.

Restricted Stock and RSUs

Our stock compensation plans allow grants of restricted stock and RSUs. Restricted stock is issued on the grant date but is restricted as to transferability. RSU awards represent the right to receive common stock when vesting occurs.

Restricted stock and RSU grants generally vest over periods ranging from one to ten years of service. Compensation cost for these awards is based on the closing market price of our common stock on the date of grant. Stock-based compensation expense is based on the awards ultimately expected to vest, and has been reduced for estimated forfeitures.

The following table summarizes the status under the provisions of SFAS 123R of our restricted stock and RSUs at December 31, 2007 and the changes during the year then ended:

	Equity Instruments (thousands)	Weighted Average Fair Value	Aggregate Intrinsic Value ($ thousands)	Weighted Average Remaining Contractual Life (Years)
Nonvested at January 1, 2007	3,053	$39.18		
Granted	1,130	48.43		
Vested	(493)	38.83		
Forfeited	(29)	48.24		
Reclassified from liability instruments	1,275	46.90		
Nonvested at December 31, 2007	4,936	43.26	$266,544	4.0

	Liability Instruments (thousands)	Weighted Average Fair Value	Aggregate Intrinsic Value ($ thousands)	Average Remaining Contractual Life (Years)
Nonvested at January 1, 2007	1,275	$47.53		
Reclassified to equity instruments	(1,275)	46.90		
Nonvested at December 31, 2007	—	—	$ —	—

The total intrinsic value of restricted stock and RSUs vested in 2007, 2006 and 2005 was $26.3 million, $35.0 million and $57.2 million, respectively. The intrinsic value is based upon the closing price of Company's common stock on the date restricted stock and RSUs vested. The weighted average grant date fair value of RSUs granted during the years ended December 31, 2006 and 2005 was $41.40 per share and $38.17 per share, respectively.

In 2006, we granted 300,000 RSUs to certain executives that will vest only upon the event of a change of control (as defined). Because, in the Company's assessment, a change of control is not probable no compensation cost has been recognized for these awards.

The tables above include 2.3 million shares granted under the 2004 Plan in accordance with the provisions of our Long-Term Retention and Deferred Compensation Plan. The plan allows certain executive officers to defer awards of equity compensation and in lieu thereof, an equivalent number of

RSUs available under stockholder-approved plans will be credited to an account for the executive. Under the terms of this plan, certain executives have been granted the right under the 2004 Plan to receive annual RSU grants beginning in 2005 and continuing until 2014. Each annual credit is subject to continued service by the executive. Under the provisions of SFAS 123R, all such future grants are deemed granted in 2005 for the purpose of determining stock-based compensation expense. The weighted average grant date fair value for all these shares was $40.40. The grants have varying vesting dates from 2010 through 2015 but payment of vested RSUs will be generally deferred until September 30, 2015, subject to certain exceptions. At January 1, 2006, these RSUs were classified as equity instruments (as defined in SFAS 123R) and the valuation under SFAS 123R was unchanged from the intrinsic valuation under APB 25. Certain of the awards were classified as liability awards at December 31, 2006 (as defined in SFAS 123R) because we did not have sufficient shares available for issuance under the 2004 Plan for all shares to be granted through 2014, and such RSUs were revalued to their fair value on that date of $47.53 per share. On May 3, 2007, our stockholders approved an amendment to the 2004 plan increasing the total number of shares by 3.4 million which provided the plan with enough shares available to be granted through 2014. As a result, all of these RSUs which were classified as liability awards were reclassified as equity awards and revalued on that date with an average price of $46.90 per share.

In addition, under the terms of our Long-Term Retention and Deferred Compensation Plan, annual grants may be increased if certain common stock price based performance targets are achieved. No expense was recognized in 2005 under APB 25 for the incremental shares because it was not probable that the target stock price would be met. Upon our adoption of SFAS 123R the awards were revalued under the fair value approach in accordance with the provisions of SFAS 123R. At December 31, 2006, these awards were classified as liability awards because we did not have sufficient shares available for issuance under the 2004 Plan. However, on May 3, 2007, our stockholders approved an amendment to the 2004 plan increasing the total number of shares by 3.4 million which provided the plan with enough shares available to be granted through 2014. All of these awards, which were classified as liability awards, were reclassified as equity awards and revalued on that date. We used a Monte-Carlo simulation model to estimate the value and number of RSUs expected to be granted in the future. This model involves forecasting potential future stock price paths based on the expected return on the common stock and its volatility, then calculating the number of RSUs expected to be granted based on the results of the simulations.

The following assumptions were used with respect to the Monte Carlo simulation model:

Expected annual return	9.80%
Expected daily return	0.04%
Daily standard deviation	2.09%

At December 31, 2007, we estimated that 0.4 million restricted units would be granted as a result of achieving the common stock price based targets. Such units had a weighted average fair value of $46.61 per unit, an aggregate fair value of $18.7 million and a weighted average remaining contractual life of 6 years.

Stock Options

As a result of the acquisition of Nuevo in 2004, we converted certain of Nuevo's outstanding stock options to options on our common stock. At December 31, 2007, there were 65,474 options outstanding with an average exercise price of $13.13 per share and an average remaining life of 2.1 years. The intrinsic value of options exercised in the years ended December 31, 2007, 2006 and 2005 was $0.3 million, $1.5 million and $4.7 million, respectively, and the Company received $0.1 million, $0.9 million and $4.3 million, respectively, upon the exercise of such options.

Other

We have a 401(k) defined contribution plan whereby we have matched 100% of an employee's contribution (subject to certain limitations in the plan). Matching contributions were made 100% in cash. In 2007, 2006 and 2005 we made contributions totaling $5.5 million, $4.9 million and $4.4 million, respectively, to the 401(k) plan.

The Company has certain awards which have vested, but, at the election of the award recipient, the issuance of those common shares has been deferred. During 2007 and 2006, approximately 63,000 and 30,000 common shares, respectively, vested and were deferred resulting in total deferred common shares of approximately 93,000 common shares at December 31, 2007. These common shares will be issued upon the earliest of the deferral date designated by the recipient, their retirement from the Company or death.

Note 8—Pension and Post-retirement Benefits

Pension Plan

As a result of our acquisition of Pogo, we assumed responsibility for a defined benefit pension plan for former employees of Pogo ("Pogo Pension Plan"). Benefits under the plan are based on years of service and the employees' average compensation for five consecutive years within the final ten years of service which produced the highest average compensation. Upon closing the Pogo acquisition, PXP notified all employees that the Pogo Pension Plan would be frozen 45 days following notice to employees and that PXP would terminate the plan. Pogo employees who accepted full time and transition employment offers with PXP continued to accrue benefits during the 45 day period before the plan was frozen. Such benefits will not increase based upon future service completed or compensation received after that date.

The following tables summarize changes in the benefit obligation, the fair value of plan assets and the funded status of the pension plan as well as the components of net periodic benefit costs, since the Pogo acquisition (in thousands).

	Pension Benefits
Change in benefit obligation:	
Benefit obligation at November 6, 2007	$10,547
Interest cost	99
Benefits paid	(10)
Actuarial gain	(1,677)
Benefit obligation at December 31, 2007	8,959
Change in plan assets:	
Fair value of plan assets at November 6, 2007	7,751
Actual return on plan assets	915
Employer contributions	1,600
Benefits paid	(10)
Fair value of plan assets at December 31, 2007	10,256
Overfunded status	$ 1,297
Reconciliation of funded status:	
Funded status	$ 1,297
Net amount recognized	$ 1,297
Components of net periodic benefit cost:	
Interest cost	$ 99
Expected return on plan assets	(70)
Total periodic benefit cost	$ 29

At December 31, 2007, there was $2.5 million in OCI consisting of gains arising subsequent to the Pogo acquisition, substantially all of which are expected to be recognized upon termination of the plan.

Plan assumptions to determine benefit obligations	
Discount rate	6.20%
Plan assumptions to determine net cost	
Discount rate	6.25%
Expected long-term rate of return on plan assets	6.00%

To develop the expected long-term rate of return on plan assets assumption, the Company considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on plan assets assumption for the portfolio. This resulted in the selection of a 6.00% assumption.

The Company determined the discount rate used to measure plan liabilities as of the December 31 measurement date. The discount rate reflects the current rate at which the associated liabilities could be effectively settled at the end of the year. In determining this rate, the Company reviews rates of return on fixed-income investments of similar duration to the liabilities in the plan that receive high, investment grade ratings by recognized ratings agencies. These rates were used to develop an equivalent single discount rate based on the plans' expected future benefit payment streams and duration of plan liabilities. Using this methodology, the Company determined a discount rate of 6.20% to be appropriate as of December 31, 2007.

Expected benefit payments for 2008, the year in which the plan is expected to be terminated, are $9.0 million.

Other Post-retirement Benefits

As a result of the Pogo acquisition, PXP is currently providing medical coverage to an eligible group of retired Pogo U.S. employees and their eligible dependents, although the Company has no obligation to do so. The portion of the cost of this coverage being paid by PXP will be reduced in each of the next two years until the retirees are paying the full cost of their coverage at the beginning of 2010. The post-retirement medical plan has no assets, and the Company is funding it on a pay-as-you-go basis. The post-retirement benefit obligation at December 31, 2007 was $0.4 million.

Note 9—Income Taxes

For the years ended December 31, 2007, 2006 and 2005 our income tax expense (benefit) consisted of (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Current			
U.S. Federal	$ (2,158)	$118,659	$ (872)
State	(2,519)	23,719	643
	(4,677)	142,378	(229)
Deferred			
U.S. Federal	110,080	216,117	(119,606)
State	4,345	26,402	(11,023)
	114,425	242,519	(130,629)
	$109,748	$384,897	$(130,858)

Our deferred income tax assets and liabilities at December 31, 2007 and 2006 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, 2007	December 31, 2006
Deferred tax assets:		
Net operating loss	$ 205,372	$ 8,468
Tax credits	36,774	14,556
Commodity derivative contracts and other	111,296	71,363
	353,442	94,387
Deferred tax liabilities:		
Net oil & gas acquisition, exploration and development costs and other	(2,082,980)	(509,582)
Net deferred tax liability	$(1,729,538)	$(415,195)
Current asset	$ 229,893	$ 51,084
Long-term liability	(1,959,431)	(466,279)
	$(1,729,538)	$(415,195)

Tax carryforwards at December 31, 2007, which are available for future utilization on income tax returns, are as follows (in thousands):

FEDERAL	Amount	Expiration
Alternative minimum tax (AMT) credit	$ 3,268	—
Enhanced oil recovery credit	20,747	2025
Net operating loss—regular tax	540,006	2022-2027
Net operating loss—AMT tax	111,394	2027
STATE		
Alternative minimum tax (AMT) credit	$ 520	—
Enhanced oil recovery credit	26,765	2016-2020
Net operating loss—regular tax	350,173	2012-2027
Net operating loss—AMT tax	53,972	2017

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

	Year Ended December 31, 2007	2006	2005
U.S. federal income tax provision at statutory rate	$ 93,975	$344,613	$(120,704)
State income taxes, net of federal benefit	1,826	33,754	(13,201)
Enhanced oil recovery credits generated	—	—	(19,637)
Non-deductible expenses	9,882	7,947	18,981
Other	4,065	(1,417)	3,703
Income tax expense (benefit) on income before income taxes and cumulative effect of accounting change	$109,748	$384,897	$(130,858)

Tax Loss Carryovers. Certain of our U.S. tax loss carryovers obtained as a result of the acquisitions of Nuevo and Pogo are subject to Internal Revenue Code limitations as to the amount that can be used each year. We do not expect these limitations to materially impact our ability to utilize these losses in future periods.

Other Tax Matters. The Company did not record a tax benefit related to non-cash employee compensation for 2007 since the Company generated a net operating loss for tax purposes. As the Company utilizes this net operating loss in future periods, a tax benefit of $1.6 million will be credited to additional paid in capital as a result of the noncash employee compensation that vested in 2007. A deferred tax benefit related to noncash employee compensation of approximately $2.9 million and $1.6 million was credited to additional paid in capital in 2006 and 2005, respectively.

As a result of the acquisition of Nuevo in 2004 we converted certain of Nuevo's outstanding stock options to options on our common stock. The tax benefit related to these options of approximately $0.2 million and $1.1 million was credited to goodwill in 2006 and 2005, respectively.

Under the terms of a tax allocation agreement between PXP and Plains Resource, Inc. ("Plains Resources", currently known as Vulcan Energy Inc.), we have agreed to indemnify Plains Resources if the 2002 spin-off of PXP from Plains Resources 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. We may not be able to control some of the events that could trigger this indemnification obligation.

Enhanced Oil Recovery ("EOR") Credits. Under Section 43 of the Internal Revenue Code of 1986 (as amended) and similar California tax rules, taxpayers may claim EOR tax credits based on capital spending and lease operating expense of qualified projects. EOR credits are subject to a phase out according to the level of average domestic crude oil prices. As a result of the increase in oil prices in 2005 and 2006, companies did not earn EOR credits in 2006 or 2007.

FIN 48. Effective January 1, 2007, we adopted FIN 48. This interpretation clarified the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. At adoption, we recorded the cumulative effect of the change in accounting principle as a $1.4 million increase in the opening balance of retained earnings, a $0.8 million decrease in goodwill and a $2.2 million reduction in our existing reserves for uncertain tax positions. The adjustment to goodwill relates to tax positions taken with respect to Nuevo and 3TEC Energy Corporation ("3TEC") in periods prior to our acquisition of these companies in 2004 and 2003, respectively. In the fourth quarter of 2007, we recorded additional uncertain tax positions related to our acquisition of Pogo. We recorded these effects as a $4.6 million increase in goodwill and a $4.6 million increase in our reserves for uncertain tax positions.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands):

Balance at January 1, 2007	$19,732
Additions for tax positions in prior years	395
Reductions for tax positions of prior years	(556)
Additions based on tax positions related to the current year	4,799
Adjustments for audit settlements in the current year	—
Adjustments due to any expiration of a statute of limitations	—
Balance at December 31, 2007	$24,370

Included in the balance at December 31, 2007 is approximately $19.5 million that would affect our effective tax rate if recognized. This amount has increased over the amount that existed at the date of adoption of FIN 48 primarily due to the effects of the acquisition of Pogo and the enactment of SFAS 141R, which requires that future changes to certain unrecognized tax benefits be reflected in income tax expense rather than goodwill.

In addition, approximately $2.7 million of the balance represents tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deduction. Due to the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

We recognize interest and penalties related to unrecognized tax positions in income tax expense. Included in the balance of uncertain tax positions at December 31, 2007 are interest and penalties of approximately $0.5 million.

We file income tax returns in the U. S. federal and various state and foreign jurisdictions. For the previously filed PXP, Nuevo and 3TEC tax returns, we are no longer subject to U. S. federal and state income tax examinations by tax authorities for years before 1996. The Internal Revenue Service commenced an examination of the PXP and Nuevo U. S. income tax returns for 2003 and 2004, the field audit work for which is anticipated to be completed by the second quarter of 2008. As of December 31, 2007, the IRS had not proposed any significant adjustments that would result in a material change to our unrecognized tax benefits over the next 12 months.

For the previously filed Pogo tax returns, we are no longer subject to U. S. federal and state income tax examinations by tax authorities for years prior to 2003. The IRS completed an examination of Pogo's U.S. income tax returns through 2003 in the fourth quarter of 2005, which resulted in a refund to Pogo of $1.4 million. The IRS also reviewed Pogo's income tax return for 2004 and indicated they do not intend to perform an examination of that return. Based on the results of the last examination, we do not anticipate any significant adjustments for years subsequent to 2003 that would result in a material change to our financial position.

Note 10—Commitments, Contingencies and Industry Concentration

Commitments and Contingencies

Operating leases. Our operating leases relate primarily to obligations associated with aircraft, our office facilities and certain oil field equipment. Future non-cancellable commitments related to these leases are as follows (in thousands):

2008	$13,675
2009	10,520
2010	9,340
2011	8,761
2012	5,236
Thereafter	11,759
	$59,291

Total expenses related to such leases were $7.9 million, $6.2 million and $3.4 million in 2007, 2006 and 2005, respectively.

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. 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 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 receive an indemnity with respect to those costs. We cannot assure you that we will be able to collect on these indemnities.

In connection with the sale of certain properties offshore California in December 2004, we retained the responsibility for certain abandonment costs, including removing, dismantling and disposing of the existing offshore platforms. The present value of such abandonment costs, $42 million ($81 million undiscounted), are included in our asset retirement obligation as reflected on our consolidated balance sheet. In addition, we agreed to guarantee the performance of the purchaser with respect to the remaining abandonment obligations related to the properties (approximately $46 million). To secure its abandonment obligations the purchaser of the properties is required to periodically deposit funds into an escrow account. At December 31, 2007, the escrow account had a balance of $6.44 million. The fair value of our guarantee, $0.4 million, is included in Other Long-Term Liabilities in the Consolidated Balance Sheet.

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, releases of 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.

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

On November 15, 2005, the United States Court of Federal Claims issued a ruling granting the plaintiffs' motion for summary judgment as to liability and partial summary judgment as to damages in the breach of contract lawsuit Amber Resources Company et al. v. United States, Case No. 02-30c. The Court's ruling also denied the United States' motion to dismiss and motion for summary judgment. The United States Court of Federal Claims ruled that the federal government's imposition of new and onerous requirements that stood as a significant obstacle to oil and gas development breached agreements that it made when it sold 36 federal leases offshore California. The Court further ruled that the Government must give back to the current lessees the more than $1.1 billion in lease bonuses it had received at the time of sale. On October 31, 2006, the Court issued an unfavorable decision on the plaintiff's motion for partial summary judgment concerning plaintiffs' additional claims regarding the hundreds of millions of dollars that have been spent in the successful efforts to find oil and gas in the disputed lease area, and other matters. Plaintiffs filed a motion for final judgment on November 29, 2006 and the court granted such motion on January 11, 2007. Judgment on the $1.1 billion was filed January 12, 2007. The United States has filed its notice of appeal and Plaintiffs intend to file a cross-appeal concerning the Court's October 31, 2006 decision. No payments will be made until all appeals have either been waived or exhausted. We are among the current lessees of the 36 leases. Our share of the $1.1 billion award is in excess of $80 million if the plaintiffs are successful.

We are a defendant in various other lawsuits arising in the ordinary course of our business. While the outcome of these lawsuits cannot be predicted with certainty and could have a material adverse effect on our financial position, 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.

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. During 2007, 2006 and 2005, sales to ConocoPhillips accounted for approximately 45%, 54% and 44%, respectively, of our total revenues and sales to Plains Marketing, L.P. ("PMLP") accounted for approximately 31%, 41% and 38%, respectively, of our total revenues. During such periods no other purchaser accounted for more than 10% of our total revenues. The loss of any single significant customer or contract could have a material adverse short-term effect; however, we do not believe that the loss of any single significant customer or contract would materially affect our business in the long-term. We believe such purchasers could be replaced by other purchasers under contracts with similar terms and conditions. However, their role as the purchaser of a significant portion of our oil production does have the potential to impact our overall exposure to credit risk, either positively or negatively, in that they may be affected by changes in economic, industry or other conditions. We generally do not require letters of credit or other collateral from PMLP or from ConocoPhillips to support trade receivables. Accordingly, a material adverse change in PMLP's or ConocoPhillips's financial condition could adversely impact our ability to collect the applicable receivables, and thereby affect our financial condition.

The nine financial institutions that are contract counterparties for our derivative commodity contracts all have Standard & Poor's ratings of A+ or better, and all but one of the financial institutions are participating lenders in our revolving credit facility. We have a net derivative liability with the one counterparty that is not a participating lender in our revolving credit facility. As of December 31, 2007 we were in a net derivative liability position with all but two of such counterparties with whom we had a net asset position of $2.2 million.

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 11—Related Party Transactions

Our Chief Executive Officer is a director of Vulcan Energy Corporation ("Vulcan Energy", formerly known as Plains Resources) and until August 2005 held an interest in the general partner of Plains All American Pipeline, L.P. ("PAA"), a publicly traded master limited partnership. PAA is also an affiliate of Vulcan Energy. PMLP, a subsidiary of PAA, is the marketer/purchaser for a portion of our oil production under a marketing agreement that provides that PMLP will purchase for resale at market prices certain of our oil production. During the year ended December 31, 2005 the following amounts were recorded with respect to such transactions (in thousands):

	Year Ended December 31, 2005
Sales of oil to PMLP	
PXP's share	$357,174
Royalty owners' share	65,782
	$422,956
Charges for PMLP marketing fees	$ 1,233

Note 12—Financial instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of SFAS 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 our financial statements are stated at fair value. The carrying amounts and fair values of our other financial instruments are as follows (in thousands):

	December 31, 2007		December 31, 2006	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt				
Senior Revolving Credit Facility	$2,205,000	$2,205,000	$235,500	$235,500
7% Senior Notes	500,000	478,150	—	—
7¾% Senior Notes	600,000	600,000	—	—

The carrying value of the Senior Revolving Credit Facility approximates its fair value, as interest rates are variable, based on prevailing market rates. The fair value of the Senior Notes and the Senior Subordinated Notes is based on quoted market prices based on trades of such debt.

Note 13—Supplemental Cash Flow Information

Cash payments for interest and income taxes were (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Cash payments for interest (net of capitalized interest)	$ 44,193	$72,046	$51,107
Cash payments for income taxes	$118,876	$44,863	$ 2,141

At December 31, 2007 and 2006 accrued capital expenditures included in Accounts Payable in the consolidated Balance Sheet were $187 million and $71 million, respectively.

Common stock issued for no cash payment in connection with compensation plans (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Shares	362	901	969
Amount	$15,175	$25,959	$17,098

The 2007 Pogo acquisition involved non-cash consideration as follows (in thousands):

Common stock issued	$1,995,516
Senior Subordinated Notes	1,291,977
Current liabilities	255,461
Other noncurrent liabilities	35,287
Deferred income tax liabilities	1,224,183
Asset retirement obligation	51,976
	$4,854,400

We issued one million shares of common stock with a fair value of approximately $45 million in the Piceance Basin property acquisition to the seller.

Note 14—Stockholders' Equity

Earnings per Share

Weighted average shares outstanding for computing basic and diluted earnings for the years ended December 31, 2007, 2006 and 2005 were (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Common shares outstanding—basic	78,627	77,273	77,726
Unvested restricted stock, restricted stock units and stock options	1,181	961	—
Common shares outstanding—diluted	79,808	78,234	77,726

In 2006 and 2007, no unvested restricted stock, restricted stock units and stock options were excluded in computing earnings per share. Due to our net loss in 2005 our unvested restricted stock, restricted stock units and stock options (796,000 equivalent shares) were not included in computing earnings per share because the effect was antidilutive. In computing earnings per share, no adjustments were made to reported net income.

Authorized Shares

In November 2007, our stockholders approved an amendment to our certificate of incorporation to increase the number of authorized common shares from 150 million to 250 million.

Stock Repurchase Program

In December 2007, our Board of Directors authorized a stock repurchase program permitting us to repurchase up to $1.0 billion of our common stock, replacing the previous $500 million authorization that had approximately $158 million remaining. The shares will be repurchased from time to time in open market transactions or privately negotiated transactions at our discretion, subject to market conditions and other factors.

Note 15—Oil and Natural Gas Activities

Costs incurred

Our oil and natural gas acquisition, exploration and development activities are primarily conducted in the United States. Our international activities currently consist of exploration projects offshore New Zealand and Vietnam that were obtained in our Pogo acquisition. The following table summarizes the costs incurred during the last three years (in thousands).

	Year Ended December 31,		
	2007	2006	2005
Property acquisitions costs			
Unproved properties			
Pogo acquisition	$1,333,130	$ —	$ —
Piceance acquisition	447,971	—	—
Other	41,211	48,315	16,682
Proved properties			
Pogo acquisition	3,361,710	—	—
Piceance acquisition	517,994	—	—
Other	3,903	7,175	134,696
Exploration costs	465,246	272,352	129,066
Development costs	357,345	319,730	300,439
	$6,528,510	$647,572	$580,883

Amounts presented include capitalized general and administrative expense of $44.6 million, $34.8 million and $24.5 million in 2007, 2006 and 2005, respectively, and capitalized interest expense of $34.6 million, $7.9 million and $3.5 million in 2007, 2006 and 2005, respectively.

Capitalized costs

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

	December 31,	
	2007	2006
Property subject to amortization	$7,340,238	$2,624,277
Accumulated DD&A	(991,319)	(694,126)
	$6,348,919	$1,930,151

The average DD&A rate per equivalent unit of production was $12.92, $8.96 and $7.39 in 2007, 2006 and 2005, 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,		
	2007 (1)	2006	2005
Onshore			
Acquisition costs	$1,701,250	$ 19,031	$ 43,503
Exploration costs	997	1,848	5,061
Capitalized interest	28,018	3,227	3,819
Offshore			
Acquisition costs	31,754	13,669	37,486
Exploration costs	165,078	100,276	18,306
Capitalized interest	9,088	4,045	4,029
International			
Acquisition costs	15,457	—	—
Capitalized interest	141	—	—
	$1,951,783	$142,096	$112,204

(1) Includes $1.3 billion and $420 million attributable to the Pogo and Piceance Basin properties acquisition, respectively.

Unproved property costs not subject to amortization consist of acquisition costs related to unproved areas, exploration costs 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. Due to the nature of the reserves, the ultimate evaluation of the properties will occur over a period of several years. We expect that 75% of the costs not subject to amortization at December 31, 2007 will be transferred to the amortization base over the next five years and the remainder in the next seven to ten years. The majority of the leases covering the properties is held by production and will not limit the time period for evaluation. Approximately 94%, 3%, 1% and 2% of the balance in unproved properties at December 31, 2007, related to additions made in 2007, 2006, 2005 and prior periods, 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 and interest income. Income tax expense was determined by applying the statutory rates to pretax operating results (in thousands).

	Year Ended December 31,		
	2007	2006	2005
Revenues from oil and gas producing activities	$1,272,840	$1,018,503	$ 944,420
Production costs	(413,122)	(313,125)	(285,292)
Depreciation, depletion, amortization and accretion	(306,713)	(209,108)	(181,609)
Income tax expense	(209,589)	(197,764)	(187,210)
Results of operations from producing activities (excluding general and administrative and interest costs)	$ 343,416	$ 298,506	$ 290,309

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, 2007. The following reserve information in 2007 is based upon (1) reserve reports prepared by the independent petroleum consulting firms of Netherland, Sewell & Associates, Inc. and Ryder Scott Company L.P. ("Ryder Scott") and (2) reserve volumes prepared by us and audited by Ryder Scott and Miller and Lents, Ltd. The independent petroleum consulting firms prepared 80% of the reserve volumes, we prepared 19% of the reserve volumes, which the independent petroleum consulting firms audited and we prepared 1% of the volumes, which were not audited by an independent petroleum consulting firm. In 2006 and 2005, 100% of our reserves were based on reserve reports prepared by Netherland, Sewell & Associates, Inc. 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 the amount 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 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 natural gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, reserve volumes and our revenues, profitability and cash flow. The market price for California crude oil and natural gas in the Rocky Mountains differs from the established market indices due primarily to transportation, refining costs and quality adjustments. Approximately 74% of our 2007 reserve volumes is attributable to properties in California and the Rocky Mountains where differentials to the NYMEX reference prices have been volatile due to these factors.

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, 2007.

	As of or for the Year Ended December 31,					
	2007		2006		2005	
	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)
Proved Reserves						
Beginning balance	333,217	110,922	356,333	267,921	351,403	407,400
Revision of previous estimates	40,726	310,858	(2,045)	(3,949)	(13,002)	3,518
Extensions, discoveries and other additions	6,074	151,346	7,688	3,765	747	21,530
Improved recovery	—	—	10,095	2,438	20,134	752
Purchase of reserves in-place	74,646	976,395	—	—	17,314	12,038
Sale of reserves in-place	—	—	(19,879)	(138,624)	(1,592)	(147,958)
Production	(18,130)	(29,545)	(18,975)	(20,629)	(18,671)	(29,359)
Ending balance	436,533	1,519,976	333,217	110,922	356,333	267,921
Proved Developed Reserves						
Beginning balance	171,646	62,021	234,638	193,904	233,707	305,009
Ending balance	227,915	757,736	171,646	62,021	234,638	193,904

Standardized measure of discounted future net cash flows (unaudited)

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

	December 31,		
	2007	2006	2005
Future cash inflows	$ 46,466,516	$17,318,297	$20,133,050
Future development costs	(4,919,564)	(1,979,251)	(1,536,196)
Future production expense	(14,408,460)	(6,623,201)	(8,314,665)
Future income tax expense	(9,096,371)	(3,063,433)	(3,509,378)
Future net cash flows	18,042,121	5,652,412	6,772,811
Discounted at 10% per year	(10,418,798)	(3,141,749)	(3,690,645)
Standardized measure of discounted future net cash flows	$ 7,623,323	$ 2,510,663	$ 3,082,166

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 at December 31 of the year presented 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 use various derivative instruments to manage our exposure to commodity prices. Arrangements in effect at December 31, 2007 are discussed in

Note 4. Such arrangements are not reflected in the reserve reports. The overall average year-end sale prices used in the reserve reports as of December 31, 2007, 2006 and 2005 were $85.50, $50.71 and $51.24 per barrel of oil and liquids, respectively, and $6.28, $6.14 and $8.02 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. 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, 2007, are as follows (in thousands):

	Year Ended December 31,		
	2007	2006	2005
Balance, beginning of year	$ 2,510,663	$ 3,082,166	$ 2,236,719
Sales, net of production expenses	(856,670)	(848,676)	(797,622)
Net change in sales and transfer prices, net of production expenses	4,250,363	240,127	2,284,096
Extensions, discoveries and improved recovery, net of costs	348,785	194,904	283,222
Changes in estimated future development costs	(219,710)	(322,294)	(304,045)
Previously estimated development costs incurred during the year	184,268	196,482	224,338
Purchase of reserves in-place	3,856,043	—	240,725
Sale of reserves in-place	—	(508,692)	(276,255)
Revision of quantity estimates	3,435	52,478	(558,470)
Accretion of discount	393,743	445,583	266,113
Net change in income taxes	(2,847,597)	(21,415)	(516,655)
Balance, end of year	$ 7,623,323	$ 2,510,663	$ 3,082,166

Note 16—Quarterly Financial Data (Unaudited)

The following table shows summary financial data for 2007 and 2006 (in thousands, except per share data):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
2007 (1)					
Revenues	$224,693	$255,547	$298,969	$493,631	$1,272,840
Income from operations	62,024	71,040	110,548	176,022	419,634
Net income	20,570	25,318	32,860	80,003	158,751
Basic earnings per share	0.28	0.35	0.45	0.83	2.02
Diluted earnings per share	0.28	0.35	0.45	0.81	1.99
2006					
Revenues	$251,619	$278,386	$280,907	$207,591	$1,018,503
Gain on sale of oil and gas properties (2)	—	—	345,480	637,508	982,988
Income from operations	105,289	110,284	456,151	676,726	1,348,450
Income (loss) before cumulative effect of accounting change	(49,470)	(7,127)	272,693	383,614	599,710
Cumulative effect of accounting change, net of tax expense	(2,182)	—	—	—	(2,182)
Net income (loss)	(51,652)	(7,127)	272,693	383,614	597,528
Basic earnings (loss) per share					
Income (loss) before cumulative effect of accounting change	(0.63)	(0.09)	3.56	5.09	7.76
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Net income (loss)	(0.66)	(0.09)	3.56	5.09	7.73
Diluted earnings (loss) per share					
Income (loss) before cumulative effect of accounting change	(0.63)	(0.09)	3.50	5.02	7.67
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Net income (loss)	(0.66)	(0.09)	3.50	5.02	7.64

(1) Reflects the acquisition of Pogo effective November 6, 2007 and Piceance Basin properties effective May 31, 2007.

(2) Represents gain on the sale of oil and gas properties to subsidiaries of Oxy of $345 million and gain on the sale of non-producing oil and gas properties to Statoil Gulf of Mexico LLC of $638 million.

Note 17—Consolidating Financial Statements

We are the issuer of $600 million of 7¾% Senior Notes and $500 million of 7% Senior Notes, which are jointly and severally guaranteed on a full and unconditional basis by certain of our domestic subsidiaries (referred to as "Guarantor Subsidiaries"). Certain of our subsidiaries do not guarantee the Senior Notes (referred to as "Non-Guarantor Subsidiaries").

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

- PXP (the "Issuer" or "Parent");
- the Guarantor Subsidiaries on a combined basis;
- the Non-Guarantor Subsidiaries on a combined basis;

- elimination entries necessary to consolidate the Issuer, Guarantor Subsidiaries and Non-Guarantor Subsidiaries; and
- PXP on a consolidated basis.

The condensed consolidating balance sheet as of December 31, 2006 has been revised to correct $66.8 million of deferred income taxes payable that was previously recorded in the accounts of the Issuer but should have been recorded in the accounts of the Guarantor Subsidiaries. Stockholders' equity in the accounts of the Guarantor Subsidiaries has also been revised to reflect $35.0 million of additional current tax expense for the year ended December 31, 2006. These revisions had no impact on the consolidated or the Non-Guarantor Subsidiaries totals in the condensed consolidating balance sheet as of December 31, 2006. The condensed consolidating statement of income for the year ended December 31, 2006 has been revised to correct $35.0 million of income tax expense recorded in the accounts of the Issuer that should have been recorded in the accounts of the Guarantor Subsidiaries. This revision had no impact on the consolidated or the Non-Guarantor Subsidiaries totals in the condensed consolidating statements of income for the year ended December 31, 2006. Additionally, the condensed consolidating statement of cash flows for the year ended December 31, 2006 has been revised to correct $40.4 million of deferred tax expense recorded as an adjustment to the cash flows from operating activities of the Guarantor Subsidiaries that should have been recorded as an adjustment to the cash flows from operating activities of the Issuer, a $35.0 million reduction in equity earnings and a $75.4 million reduction in advance to affiliate in the accounts of the Issuer and a corresponding reduction in advance from affiliate in the accounts of the Guarantor Subsidiaries. Adjustments were also made to reduce the corresponding amounts in the eliminations columns to reflect the changes in the advance to affiliates. These revisions had no impact on the total cash flow for the Issuer and Guarantor Subsidiaries in the condensed consolidating statement of cash flows for the year ended December 31, 2006.

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2007
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 15,897	$ 2,261	$ 7,288	$ —	$ 25,446
Accounts receivable and other current assets	255,049	385,720	8,705	—	649,474
	270,946	387,981	15,993	—	674,920
Property and Equipment, at cost					
Oil and natural gas properties—full cost method					
Subject to amortization	2,632,802	4,707,436	—	—	7,340,238
Not subject to amortization	174,837	1,761,489	15,457	—	1,951,783
Other property and equipment	57,384	11,903	16,641	—	85,928
	2,865,023	6,480,828	32,098	—	9,377,949
Less allowance for depreciation, depletion and amortization	(529,426)	(788,164)	(21)	316,889	(1,000,722)
	2,335,597	5,692,664	32,077	316,889	8,377,227
Investment in and Advances to Subsidiaries	5,120,045	(682,139)	(26,292)	(4,411,614)	—
Other Assets	24,504	613,264	3,436	—	641,204
	$7,751,092	$6,011,770	$ 25,214	$(4,094,725)	$ 9,693,351
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Accounts payable and other current liabilities	$ 322,438	$ 404,413	$ 11,257	$ —	$ 738,108
Commodity derivative contracts	68,580	11,358	—	—	79,938
	391,018	415,771	11,257	—	818,046
Long-Term Debt	3,305,000	—	—	—	3,305,000
Other Long-Term Liabilities	170,401	102,226	—	—	272,627
Deferred Income Taxes	546,426	1,286,567	2,262	124,176	1,959,431
Stockholders' Equity	3,338,247	4,207,206	11,695	(4,218,901)	3,338,247
	$7,751,092	$6,011,770	$ 25,214	$(4,094,725)	$ 9,693,351

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING BALANCE SHEET
DECEMBER 31, 2006
(in thousands)

	Issuer	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS					
Current Assets					
Cash and cash equivalents	$ 896	$ 3	$ —	$ —	$ 899
Accounts receivable and other current assets	156,242	27,655	—	—	183,897
	157,138	27,658	—	—	184,796
Property and Equipment, at cost					
Oil and natural gas properties—full cost method					
Subject to amortization	2,131,959	492,318	—	—	2,624,277
Not subject to amortization	124,830	17,266	—	—	142,096
Other property and equipment	31,237	1,564	8,591	—	41,392
	2,288,026	511,148	8,591	—	2,807,765
Less allowance for depreciation, depletion and amortization	(390,931)	(309,310)	—	—	(700,241)
	1,897,095	201,838	8,591	—	2,107,524
Investment in and Advances to Subsidiaries	285,867	133,343	(5,585)	(413,625)	—
Other Assets	(1,674)	172,582	—	—	170,908
	$2,338,426	$ 535,421	$ 3,006	$(413,625)	$2,463,228
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current Liabilities					
Accounts payable and other current liabilities	$ 320,899	$ 44,131	$ —	$ —	$ 365,030
Commodity derivative contracts	95,162	—	—	—	95,162
	416,061	44,131	—	—	460,192
Long-Term Debt	235,500	—	—	—	235,500
Other Long-Term Liabilities	151,365	19,209	—	—	170,574
Deferred Income Taxes	404,817	61,462	—	—	466,279
Stockholders' Equity	1,130,683	410,619	3,006	(413,625)	1,130,683
	$2,338,426	$ 535,421	$ 3,006	$(413,625)	$2,463,228

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2007
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 903,599	$ 212,777	$ —	$ —	$1,116,376
Gas sales	23,979	129,437	—	—	153,416
Other operating revenues	2,569	478	1	—	3,048
	930,147	342,692	1	—	1,272,840
Costs and Expenses					
Production costs	301,575	111,480	67	—	413,122
General and administrative	104,544	18,955	507	—	124,006
Depreciation, depletion, amortization and accretion	151,883	164,172	23	—	316,078
Full cost ceiling test writedown	—	316,889	—	(316,889)	—
	558,002	611,496	597	(316,889)	853,206
Income (Loss) from Operations	372,145	(268,804)	(596)	316,889	419,634
Other Income (Expense)					
Equity in earnings of subsidiaries	(6,019)	(282)	—	6,301	—
Interest expense	(39,323)	(68,692)	—	39,107	(68,908)
Loss on mark-to-market derivative contracts	(88,993)	444	—	—	(88,549)
Interest and other income	39,181	6,105	143	(39,107)	6,322
Income (Loss) Before Income Taxes	276,991	(331,229)	(453)	323,190	268,499
Income tax (expense) benefit	(118,240)	132,497	171	(124,176)	(109,748)
Net Income (Loss)	$ 158,751	$(198,732)	$(282)	$ 199,014	$ 158,751

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2006
(in thousands)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues					
Oil sales	$ 798,802	$ 110,925	$ —	$ —	$ 909,727
Gas sales	32,110	74,209	—	—	106,319
Other operating revenues	1,579	878	—	—	2,457
	832,491	186,012	—	—	1,018,503
Costs and Expenses					
Production costs	236,346	76,779	—	—	313,125
General and administrative	115,463	7,671	—	—	123,134
Depreciation, depletion, amortization and accretion	98,225	118,557	—	—	216,782
Gain on sale of oil and gas properties	(856,602)	(126,386)	—	—	(982,988)
	(406,568)	76,621	—	—	(329,947)
Income from Operations	1,239,059	109,391	—	—	1,348,450
Other Income (Expense)					
Equity in earnings of subsidiaries	24,388	—	—	(24,388)	—
Interest expense	(50,294)	(14,381)	—	—	(64,675)
Debt extinguishment costs	(45,063)	—	—	—	(45,063)
Loss on mark-to-market derivative contracts	(297,503)	—	—	—	(297,503)
Interest and other income	43,398	—	—	—	43,398
Income Before Income Taxes and Cumulative Effect of Accounting Change	913,985	95,010	—	(24,388)	984,607
Income tax expense	(314,275)	(70,622)	—	—	(384,897)
Income Before Cumulative Effect of Accounting Change	599,710	24,388	—	(24,388)	599,710
Cumulative effect of accounting change, net of tax benefit	(2,182)	—	—	—	(2,182)
Net Income	$ 597,528	$ 24,388	$ —	$(24,388)	$ 597,528

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF INCOME
YEAR ENDED DECEMBER 31, 2005
(in thousands)

	Parent	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil sales	$ 651,689	$ 82,343	$ —	$ 734,032
Gas sales	56,292	150,444	—	206,736
Other operating revenues	2,854	798	—	3,652
	710,835	233,585	—	944,420
Costs and Expenses				
Production costs	213,594	71,698	—	285,292
General and administrative	121,586	5,927	—	127,513
Depreciation, depletion, amortization and accretion	107,789	80,126	—	187,915
	442,969	157,751	—	600,720
Income from Operations	267,866	75,834	—	343,700
Other Income (Expense)				
Equity in earnings of subsidiaries	32,600	—	(32,600)	—
Interest expense	(40,690)	(14,731)	—	(55,421)
Loss on mark-to-market derivative contracts	(636,473)	—	—	(636,473)
Interest and other income	3,324	—	—	3,324
Income (Loss) Before Income Taxes	(373,373)	61,103	(32,600)	(344,870)
Income tax benefit (expense)	159,361	(28,503)	—	130,858
Net Income (Loss)	$(214,012)	$ 32,600	$(32,600)	$(214,012)

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2007
(in thousands of dollars)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 158,751	$ (198,732)	$ (282)	$ 199,014	$ 158,751
Items not affecting cash flows from operating activities					
Depreciation, depletion, amortization and accretion	151,883	481,061	23	(316,889)	316,078
Equity in earnings of subsidiaries	6,019	282	—	(6,301)	—
Deferred income taxes	119,545	(129,196)	(100)	124,176	114,425
Commodity derivative contracts	88,993	(444)	—	—	88,549
Noncash compensation	39,067	4,630	—	—	43,697
Other noncash items	1,157	(450)	—	—	707
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	(25,417)	(28,757)	(12,050)	—	(66,224)
Accounts payable and other liabilities	78,744	(33,974)	8,581	—	53,351
Income taxes payable	(121,222)	—	—	—	(121,222)
Net cash provided by (used by) operating activities	497,520	94,420	(3,828)	—	588,112
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(528,314)	(242,095)	—	—	(770,409)
Acquisition of Piceance Basin properties	(975,407)	—	—	—	(975,407)
Acquisition of Pogo Producing Company, net of cash acquired	—	(304,676)	6,645	—	(298,031)
Increase in restricted cash	—	(59,092)	—	—	(59,092)
Derivative settlements	(99,861)	—	—	—	(99,861)
Other	(26,065)	(6,221)	(8,051)		(40,337)
Net cash used in investing activities	(1,629,647)	(612,084)	(1,406)	—	(2,243,137)
CASH FLOWS FROM FINANCING ACTIVITIES					
Revolving credit facilities					
Borrowings	4,745,100	—	—	—	4,745,100
Repayments	(2,775,600)	—	—	—	(2,775,600)
Proceeds from debt issuance	1,100,000	—	—	—	1,100,000
Redemption of long-term debt	—	(1,291,926)	—	—	(1,291,926)
Derivative settlements	(3,688)	—	—	—	(3,688)
Investment in and advances to affiliates	(1,823,876)	1,811,354	12,522	—	—
Purchase of treasury stock	(47,485)	—	—	—	(47,485)
Cost incurred in connection with financing arrangements	(47,333)	—	—	—	(47,333)
Other	10	494	—	—	504
Net cash provided by financing activities	1,147,128	519,922	12,522	—	1,679,572
Net increase in cash and cash equivalents	15,001	2,258	7,288	—	24,547
Cash and cash equivalents, beginning of period	896	3	—	—	899
Cash and cash equivalents, end of period	$ 15,897	$ 2,261	$ 7,288	$ —	$ 25,446

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2006
(in thousands of dollars)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income (loss)	$ 597,528	$ 24,388	$ —	$(24,388)	$ 597,528
Items not affecting cash flows from operating activities					
Gain on sale of oil and gas properties	(856,602)	(126,386)	—	—	(982,988)
Depreciation, depletion, amortization and accretion	98,225	118,557	—	—	216,782
Equity in earnings of subsidiaries	(24,388)	—	—	24,388	—
Deferred income taxes	271,617	(29,098)	—	—	242,519
Noncash portion of debt extinguishment costs	9,289	—	—	—	9,289
Cumulative effect of adoption of accounting change	2,182	—	—	—	2,182
Commodity derivative contracts	393,183	50,075	—	—	443,258
Noncash compensation	37,766	—	—	—	37,766
Other noncash items	(268)	—	—	—	(268)
Change in assets and liabilities from operating activities					
Accounts receivable and other assets	21,290	7,172	—	—	28,462
Accounts payable and other liabilities	(4,662)	(9,159)	—	—	(13,821)
Income taxes payable	94,272	—	—	—	94,272
Net cash provided by operating activities	639,432	35,549	—	—	674,981
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to oil and gas properties	(484,296)	(150,034)	—	—	(634,330)
Proceeds from sales of oil and gas properties	1,305,536	245,127	—	—	1,550,663
Derivative settlements	(93,411)	—	—	—	(93,411)
Other	(4,300)	(1,035)	(5,588)		(10,923)
Net cash provided by (used in) investing activities	723,529	94,058	(5,588)	—	811,999
CASH FLOWS FROM FINANCING ACTIVITIES					
Revolving credit facilities					
Borrowings	1,618,900	—	—	—	1,618,900
Repayments	(1,655,400)	—	—	—	(1,655,400)
Redemption of long-term debt	(524,863)	—	—	—	(524,863)
Derivative settlements	(621,862)	—	—	—	(621,862)
Investment in and advances to affiliates	124,020	(129,608)	5,588	—	—
Purchase of treasury stock	(298,445)	—	—	—	(298,445)
Excess tax benefit from stock-based compensation	2,899	—	—	—	2,899
Other	(8,862)	—	—	—	(8,862)
Net cash provided by (used in) financing activities	(1,363,613)	(129,608)	5,588	—	(1,487,633)
Net increase (decrease) in cash and cash equivalents	(652)	(1)	—	—	(653)
Cash and cash equivalents, beginning of period	1,548	4	—	—	1,552
Cash and cash equivalents, end of period	$ 896	$ 3	$ —	$ —	$ 899

PLAINS EXPLORATION & PRODUCTION COMPANY

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2005
(in thousands)

	Parent	Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES				
Net income (loss)	$ (214,012)	$ 32,600	$(32,600)	$ (214,012)
Items not affecting cash flows from operating activities				
Depreciation, depletion, amortization and accretion	107,789	80,126	—	187,915
Equity in earnings of subsidiaries	(32,600)	—	32,600	—
Deferred income taxes	(79,257)	(51,372)	—	(130,629)
Commodity derivative contracts	563,873	56,691	—	620,564
Noncash compensation	55,271	—	—	55,271
Other noncash items	(93)	—	—	(93)
Change in assets and liabilities from operating activities, net of effect of acquisitions				
Accounts receivable and other assets	(16,636)	(14,777)	—	(31,413)
Accounts payable and other liabilities	(20,275)	(3,994)	—	(24,269)
Net cash provided by operating activities	364,060	99,274	—	463,334
CASH FLOWS FROM INVESTING ACTIVITIES				
Additions to oil and gas properties	(295,730)	(213,397)	—	(509,127)
Proceeds from sales of oil and gas properties	9,345	337,105	—	346,450
Other	(5,419)	(324)	—	(5,743)
Net cash (used in) provided by investing activities	(291,804)	123,384	—	(168,420)
CASH FLOWS FROM FINANCING ACTIVITIES				
Revolving credit facilities				
Borrowings	1,504,200	—	—	1,504,200
Repayments	(1,342,200)	—	—	(1,342,200)
Costs incurred in connection with financing arrangements	(1,600)	—	—	(1,600)
Derivative settlements	(453,443)	(6,007)	—	(459,450)
Investment in and advances to affiliates	217,316	(217,316)	—	—
Other	4,143	—	—	4,143
Net cash (used in) financing activities	(71,584)	(223,323)	—	(294,907)
Net increase (decrease) in cash and cash equivalents	672	(665)	—	7
Cash and cash equivalents, beginning of period	876	669	—	1,545
Cash and cash equivalents, end of period	$ 1,548	$ 4	$ —	$ 1,552

company information

executive officers:

James C. Flores
Chairman, President and
Chief Executive Officer

Doss R. Bourgeois
Executive Vice President
Exploration & Production

Winston M. Talbert
Executive Vice President
and Chief Financial Officer

John F. Wombwell
Executive Vice President
and General Counsel

directors

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

Isaac Arnold, Jr.
President of The Arnold Corporation
and Former Chairman of
Quintana Petroleum Corporation

Alan R. Buckwalter, III
Retired, Chairman
and Chief Executive Officer
JPMorgan 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

Thomas A. Fry, III
President
National Ocean Industries Association

Robert L. Gerry, III
Chairman and Chief Executive Officer
VAALCO Energy, Inc.

Charles G. Groat
Director of the Center for International
Energy and Environmental Policy and
Director of the Energy and Earth Resources
Graduate Program at the University of
Texas at Austin

John H. Lollar
Managing Partner
Newgulf Exploration L.P.

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, 2007, is available free of charge on request to:
Investor Relations
Plains Exploration & Production Company
700 Milam, Suite 3100
Houston, Texas 77002
713.579.6000 or 800.934.6083

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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1201 Louisiana Street, Suite 2900
Houston, Texas 77002-5678

CORPORATE HEADQUARTERS

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statement regarding forward-looking statements

This annual Report on Form 10-K includes forward-looking information regarding PXP that is intended to be covered by the safe harbor for "forward-looking statements" provided by the Private Securities Litigation Reform Act of 1995. 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. Although we believe that our expectations are based on reasonable assumptions, there are risks, uncertainties and other factors that could cause actual results to be materially different from those in the forward-looking statements. These factors include, among other things:

- 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, including the impact on our reserve volumes and values and our earnings as a result of our derivative positions;
- 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 success of our derivative activities;
- the success of our risk-management activities;
- unexpected difficulties in integrating our operations as a result of any significant acquisitions;
- the effects of competition;
- 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 reliance on these statements without also considering the risks and uncertainties associated with these statements and our business that are discussed in this report and our other filings with the SEC. 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 for any obligation to disclose material information under the Federal securities laws, we do not intend to update these forward-looking statements and information. See Item 1A—"Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Factors That May Affect Future Results" in this report for additional discussions of risks and uncertainties.

available information

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document we file at the SEC's Public Reference Room at 100 F Street, N.E. Room 1580, 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 website at **www.sec.gov**. No information from the SEC's website is incorporated by reference herein. Our website is **www.pxp.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 website. These documents are posted to our website as soon as reasonably practicable after we have filed or furnished these documents with the SEC. We have placed on our website copies of our Corporate Governance Guidelines, charters of our Audit, Organization & Compensation and Nominating & Corporate Governance Committees and our Policy Concerning Corporate Ethics and Conflicts of Interest. Stockholders may request a printed copy of these governance materials by writing to the Corporate Secretary, Plains Exploration & Production Company, 700 Milam, Suite 3100, Houston, TX 77002.

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PXP

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