P R O G R E S S

PIONEER NATURAL RESOURCES ANNUAL REPORT 2006

STEADY PROGRESS

PROVED OIL AND GAS RESERVES
905 MILLION BARRELS OIL EQUIVALENT*

2007 CAPEX BUDGET
$1.1 BILLION

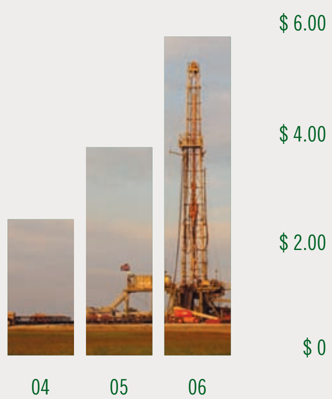
*Proved reserves as of 12/31/06; 89% of proved reserves audited by Netherland, Sewell & Associates, Inc.

2006 ACCOMPLISHMENTS

- North American production up 12%*
- Drilled 1,100 wells with 96% success
- Replaced 200% of production with new proved reserves
- Net income per diluted share up 53%
- Completed $1 billion share repurchase program
- Maintained strong balance sheet with net debt-to-book capitalization of 33% at year end

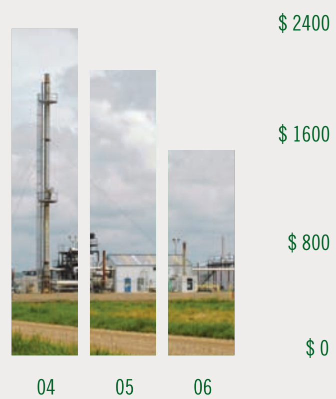
* 2005 production pro forma for divestitures; assumes VPP volumes in place for all of 2005.

EARNINGS PER SHARE
(DILUTED)



WELLS DRILLED

LONG-TERM DEBT
(MILLIONS)



AREAS OF OPERATION

1. Alaska North Slope
2. Alaska Cook Inlet
3. Northeast British Columbia
4. South Central Alberta
5. Western Colorado and Eastern Utah
6. Southern Colorado
7. Western Kansas
8. Texas Panhandle
9. West Texas
10. South Texas
11. Louisiana and Mississippi
12. Southern Tunisia
13. West Africa
14. South Africa

FORWARD-LOOKING STATEMENTS: Except for historical information contained herein, the statements in this document are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer Natural Resources Company are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described in Items 1, 1A and 7A and on page 3 of Pioneer's Form 10-K included with this report.

ACHIEVING INITIATIVES

FELLOW SHAREHOLDERS:

Pioneer made significant progress during this past year as we executed our plan to refocus our strategy on oil and gas resources in North America. To navigate the shift in strategy, we launched a number of critical initiatives, and by the end of 2006, all of these initiatives were completed.

- Capital was diverted from higher-risk exploration and reallocated to lower-risk onshore North American assets.
- Divestitures of deepwater Gulf of Mexico and Argentine assets were closed in March 2006 and April 2006, respectively, for approximately $1.8 billion.
- 8.8 million shares of common stock were repurchased for an average of $39.16 per share during 2006.
- The dividend on common shares was increased 20% in 2005 and 8% in 2006, resulting in total dividends of $0.25 per share during 2006.

For 2006, Pioneer's net income per share increased 53% to $5.81, reflecting a substantial gain from the asset sales, and income from continuing operations remained fairly constant at $1.36 per share. We benefited from stronger prices for oil, offset by somewhat lower prices for natural gas and pressure on our drilling and operating costs resulting from rising demand for services and equipment. We strengthened our balance sheet, and net debt represented 33% of total book capitalization at year end.

Our North American assets, which represent approximately 98% of proved reserves and 93% of daily production, drove our strong worldwide operating results for 2006.

- Drilled 1,100 wells with 96% success
- Added 91 million barrels of oil equivalent proved reserves
- Replaced 200% of production at $18.36 per barrel oil equivalent
- Increased production from North America by 12%*
- Increased total production per share by 19%*
- Drilled 10 discoveries in two emerging growth areas – South Texas and Tunisia
- Made significant progress on two large multi-year development projects in Alaska and South Africa

* 2005 production pro forma for divestitures; assumes VPP volumes in place for all of 2005.

These and other results are detailed in the financial statements included with this report.

Our production from continuing North American operations grew steadily throughout the year, demonstrating the strength of our core areas and multi-year inventory of drilling locations. For 2007, we expect more of the same from these areas as we continue our active drilling programs.

We were not satisfied with our 2006 stock price performance. With the sale of relatively short-lived assets in deepwater Gulf of Mexico and Argentina, cash flow declined as expected. Even though the proceeds received from the divestitures reflected historic highs and were accretive to Pioneer's net asset value per share, the stock price declined.

We recognize that a strategy shift creates uncertainty, but we remain convinced that the renewed focus on North America offers Pioneer and our shareholders the best path to growth over the next ten years. We heard from a number of you that you needed proof that the new strategy would work. Pioneer delivered consistent results through 2006, and we expect to continue to deliver in 2007 and beyond to provide proof that our plan is working.

As I stated last year, we expect to achieve compounded average production growth in excess of 10% per year over the next five years, and we expect absolute production growth of more than 10% in 2007. Our plan to primarily concentrate on predictable oil and gas basins in North America that can deliver strong, consistent development drilling results will provide the foundation for that growth, and the large development projects in South Africa and Alaska are progressing toward first production in the second half of 2007 and in 2008, respectively.

With a total of ten new discoveries, South Texas and Tunisia are emerging as new growth vehicles. We are also currently evaluating pilot programs in several conventional and unconventional resource plays in North America that offer potential to enhance our growth profile in years to come.

Progress such as this is challenging and requires diligent effort on the part of each employee. I appreciate their diligence as well as their attention to health and safety and protecting the environment. These same employees rose to another challenge, volunteering their time and joining Pioneer in providing financial support to many worthy causes in our communities.

Long-time board member, Jerry Jones, retired from the board of directors in May 2006. We appreciate Jerry's many years of service to Pioneer and his commitment to our success.

While we made good progress in 2006, there is still more work ahead. We press on with confidence in our ability to execute our strategy and deliver top-tier performance. We appreciate your support.

Scott D. Sheffield

Scott D. Sheffield
Chairman and CEO

"We delivered consistent results through 2006 supporting our belief that our renewed focus on North America offers Pioneer and our shareholders the best path to growth over the next ten years."


OUR CULTURE

Pioneer's mission is to deliver a highly-competitive and sustainable rate of return to shareholders by responsibly finding and producing oil and gas resources to help meet the world's energy demands as we provide opportunities for growth and enrichment to our employees, our business partners and the communities in which we operate.

With the cooperation of the Colorado Division of Wildlife and several area ranchers, Pioneer is studying elk populations in the Raton Basin to gain knowledge of how elk react to CBM drilling and operations.


OUR VALUES

Respect	**We respect the individual, community and environment.**
Ethics and Honesty	**We are ethical and honest in all of our business dealings.**
Safety	**We are diligent in protecting the safety of our people and the environment.**
Personal Accountability	**We are disciplined and personally accountable for our decisions, actions, attitude and results.**
Entrepreneurship	**We have an entrepreneur's mindset, driving innovation and striving for excellence in all we do.**
Communication	**We openly communicate among all levels and between departments and divisions.**
Teamwork	**We believe in working as a team toward common objectives with a 'can-do' attitude.**

A CULTURE OF RESPECT

Respect for the individual, community and environment is deeply rooted in our corporate culture. It's just who we are. We believe that our solid corporate governance practices, our high ethical standards and our respect for the world around us are critical to sustainable financial success and protecting the interests of our stakeholders.

For our efforts to safeguard the environment, Pioneer has been recognized by the Interstate Oil and Gas Compact Commission and the U.S. Environmental Protection Agency. To minimize impact on native animal species where we operate, we have several studies underway in conjunction with state and local wildlife agencies. During 2006, Pioneer also partnered with the U.S. National Park Service to build a birdwalk for visitors to more easily observe the more than 200 species of birds in the Lake Meredith National Recreation Area near our operations in the Texas Panhandle.

Pioneer also strives to foster a culture of employee giving and volunteerism in the communities where we live and work. Our employees, supported by matching contributions from Pioneer, give generously of their time and resources to many charitable organizations, including the United Way and Habitat for Humanity. Recognizing the burden of rising energy costs, we're sponsoring a program to assist needy senior citizens in the communities near our Colorado operations with their winter heating bills while also continuing our support for the state-wide energy assistance program for low-income families.

Our sense of corporate responsibility is built upon solid corporate governance practices, and our Code of Business Conduct and Ethics holds all directors, officers and employees to strict ethical standards. Independent Directors make up each Board committee and provide strategic oversight. But we believe that it takes more than strong oversight to achieve true leadership in corporate responsibility. Leadership in this area requires a corporate culture of empowerment where all employees assume personal responsibility for ensuring that our practices and actions respect others and the world around us.

EXPANDING OPPORTUNITY

TEXAS

Texas continues to be a cornerstone for Pioneer's operations with a long history of ongoing success in West Texas and a strong field expansion program underway in South Texas.

In the Permian Basin of West Texas, Pioneer's Spraberry field, with its long-lived oil and gas reserves, stable production and low maintenance capital requirements, is delivering solid returns and steady production growth. We accelerated our drilling pace during 2006 and increased Spraberry production by 21%. New reserves and production from the deeper Wolfcamp formation contributed to these strong results.

We are the largest producer in the field, which covers more than 11,000 square miles, and we increased our position during 2006 with several attractive bolt-on acquisitions, which added sizeable leasehold acreage and new untapped resource potential. During 2007, with a multi-year inventory of well locations, we expect more of the same as we continue our active drilling pace.

In the Texas Panhandle and extending north into Kansas, Pioneer's long-lived West Panhandle and Hugoton gas fields offer dependable production and cash flow and also contribute to our solid North America foundation.

Pioneer is the most active driller in the Edwards Reef trend in South Texas and drilled six new discoveries during 2006 with total program success of 88%, providing evidence of the development growth potential of the play.

We have established a large and growing acreage position along the trend, and during 2007, we will complete a substantial seismic program over existing discoveries and initiate full-scale development drilling. New well stimulation techniques have also shown promise in reenergizing existing wells. This emerging growth asset is expected to deliver significant additions to production and reserves over the next few years.

To manage rising well service costs in the Permian Basin, Pioneer is employing its Raton Basin expertise with integrated services and purchased 14 well service units during 2006.

"We've made substantial progress in expanding our opportunities in the Permian Basin and the Edwards Trend area where we have dominant positions and the experience and technical capability to exploit opportunities to their full potential."

Danny Kellum
Executive Vice President, Domestic Operations

CONTINUED SUCCESS

"Our Raton team had another strong year of increasing production through accelerated drilling and optimized facilities. And I'm especially encouraged with the progress in western Colorado and Utah where our teams have a number of promising new projects under evaluation."

Jay Still
Executive Vice President, Western Division

In the Raton Basin, Pioneer owns and operates most of its drilling and service equipment, including coiled-tubing drilling rigs, which allows the Company to control costs and the availability of services.

ROCKY MOUNTAINS

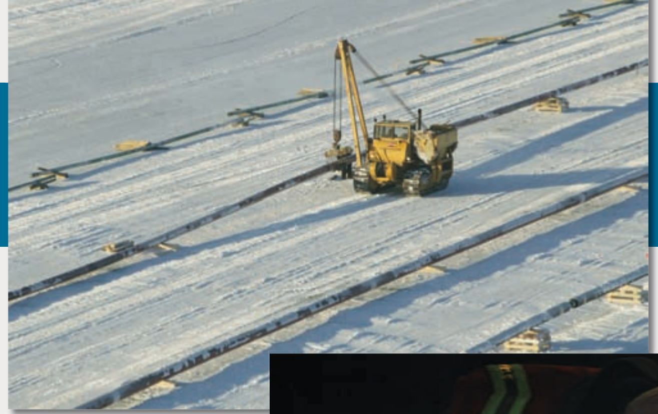
Progress in the Rocky Mountains continues in Pioneer's core area in the Raton Basin of southeastern Colorado and in several pilot programs in western Colorado and eastern Utah.

Pioneer is the largest operator in the Raton Basin, where its long-lived CBM production provides a strong foundation for the growth generated by new drilling. We drilled approximately 300 wells in the Raton field, expanded pipelines and improved field compression during 2006, leading to a 10% increase in annual production.

A similar drilling program is planned for 2007, supported by our large inventory of well locations. Pioneer operates in Colorado under an integrated field services model, and by owning much of the equipment required to drill and operate Raton wells, we've been able to achieve industry-leading efficiencies in our operations and maintain control over the equipment needed to execute our drilling program. We also plan to continue to add gas compression facilities in the Raton field to optimize production.

Our expertise in the Raton Basin is being leveraged in other CBM projects in the Rockies and elsewhere in North America. In both Colorado and Utah, Pioneer has CBM pilot programs in the Uinta, Piceance and Sand Wash basins. With the drilling completed during 2006, we will now monitor well performance to determine commerciality and expect minimal capital investment during 2007. Pioneer's CBM expertise is also being applied in Canada, where our 2006 development drilling program in the Horseshoe Canyon area generated significant production and proved reserves growth.

NEW FRONTIERS



ALASKA

Pioneer first entered Alaska in 2002 and has since made record-setting progress. We foresaw an opportunity to leverage the streamlined processes and cost reduction practices of an independent in an environment dominated by major oil companies and are targeting mid-sized projects that offer untapped commercialization potential.

We drilled three exploration wells in the Ooguruk field area on Alaska's North Slope during the 2002/2003 abbreviated winter season, gaining sufficient information to initiate an evaluation of the commercial potential of the field. In 2006, after extensive engineering and geologic evaluations, Pioneer approved Ooguruk as our first field development project in Alaska and immediately launched field development activities.

The field is five miles offshore in approximately five feet of water, and during 2006, a gravel island was built to accommodate development drilling and field operations. The island and associated onshore facilities are being equipped during this winter season, and development drilling is expected to begin during the second half of 2007. First oil production from the Ooguruk field is expected in 2008, when Pioneer will become the first independent company to operate a producing field on the North Slope.

In the Cook Inlet in southern Alaska, we are evaluating a similar opportunity to develop the Cosmopolitan field, which was discovered more than 30 years ago. Pioneer participated in a 3-D seismic survey over the field in 2005, has been elected operator of the unit and plans to drill an appraisal well during the second half of 2007 to test the potential for the field.

Pioneer is also participating in two exploration wells being drilled in the National Petroleum Reserve – Alaska during the first half of 2007.

More than eight miles of pipeline and cable systems are being installed to transport production from Ooguruk to onshore processing facilities, to transmit data and to supply the island with water, fuel and power. The drilling rig will be transported to the island before the end of the ice road season.

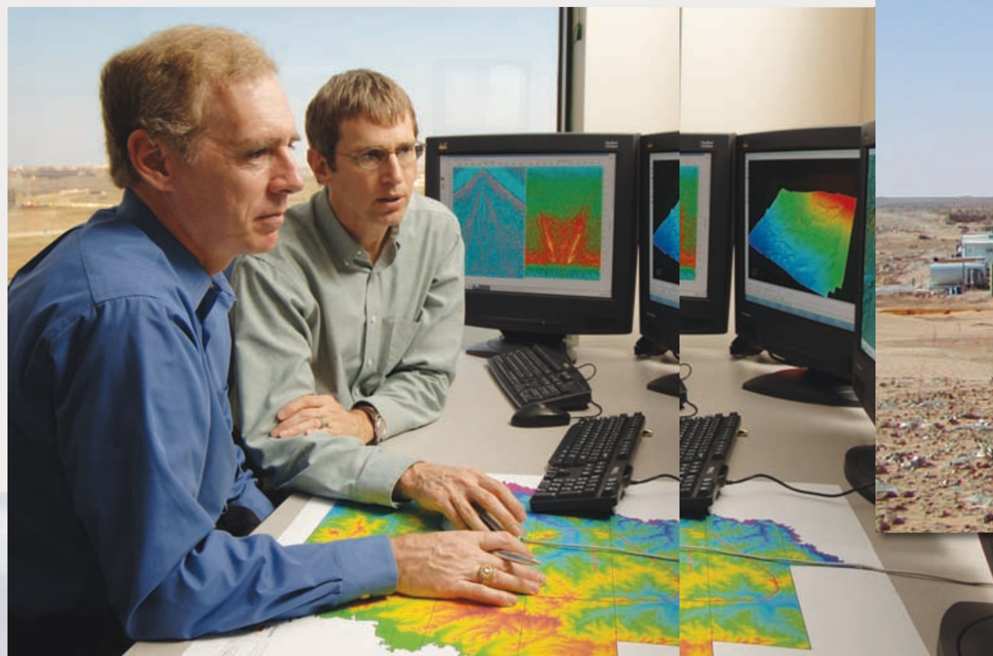
"The Pioneer Alaska team is exceeding expectations and making strong progress. The Ooguruk project team continues to achieve challenging milestones and has positioned Pioneer to become, in 2008, the first independent company to operate a North Slope field."

Ken Sheffield
President – Pioneer Alaska

CORE AREA POTENTIAL

"With our continued exploration success in the Adam Concession and the extension of that success into two adjacent blocks, including our own operated block, I am confident that we have the momentum and the expertise to develop North Africa into a new core area for Pioneer."

David McManus
Vice President, International Operations



NORTH AFRICA

Pioneer made significant progress in Tunisia over the past year. Since 2001, we have built a sizeable position in the Ghadames Basin of southern Tunisia and now hold interests in five blocks totaling approximately 4 million acres. During 2006, drilling success continued in the Adam Concession and was extended to two adjacent blocks.

In January 2007, we announced four discoveries and a successful development well in Tunisia. The development well and one of the new discoveries were drilled in the Adam Concession, where Pioneer has participated in 11 wells with 10 successes. By year-end 2006, with the new development well tied in to sales lines, gross production from Adam reached more than 20,000 barrels per day. The new discovery well on the Adam Concession is expected to be tied in and producing by the end of the first quarter of 2007.

The three other oil discoveries in Tunisia extend Pioneer's successful exploration program to two blocks bordering the Adam Concession. We drilled two of the discoveries on the Jenein Nord Block, which we operate, and one discovery on the Borj El Khadra Block. New 3-D seismic data was also acquired during 2006 to further optimize the drilling program going forward. With the additional production potential that these discoveries offer, Tunisia is emerging as a new growth vehicle for Pioneer with prospects of achieving core area status, especially as we evaluate opportunities to extend our North Africa position into neighboring Libya and Algeria.

Under our 2007 capital budget, we plan to drill at least two additional exploration wells on our Jenein Nord Block and two additional wells on the Adam Concession. As the new discoveries are brought on production, we will monitor their performance and may drill additional exploration and appraisal wells later in the year.

Pioneer and PetroSA finalized the terms for jointly developing South Coast gas fields in September 2005. Sipho Mkhize, PetroSA President and CEO, and Scott Sheffield, Pioneer Chairman and CEO, signed the agreement during the 2005 World Petroleum Congress held in Johannesburg, South Africa.

"The South Coast Gas project is making steady progress toward first production later in 2007. The volume of gas supplied by the project is expected to rise over the next few years and is an important source of energy for South Africa."

Tim Dove
President and Chief Operating Officer

SOUTH AFRICA

Offshore South Africa, oil production from the Sable field continues to exceed our original expectations, and the South Coast Gas (SCG) project is on target to begin production during the second half of 2007. In partnership with PetroSA, the national petroleum company of South Africa, we made significant progress during 2006 on the SCG project, the subsea development of a series of gas discoveries to supply a gas-to-liquids (GTL) plant at Mossel Bay.

Gas from six subsea wells will be tied into the existing F-A Platform for transport to the GTL plant, which supplies South Africa with synthetic gasoline. During 2006, most of the development wells were drilled and the subsea equipment was fabricated. Drilling has now commenced on the last of the six development wells, and subsea equipment and pipelines will be installed during the first half of 2007 in order for gas sales to commence later in the year.

Pioneer's production from South Africa is expected to increase by more than 20% in 2007, and our SCG production is expected to continue to grow as other supplies of gas to the GTL plant from fields that Pioneer does not own continue to decline. Sales proceeds from the project are indexed to oil prices, which supports expectations for strong financial returns.

SCG is the second successful joint development effort of Pioneer and PetroSA. The first joint development was the Sable oil field which began producing in 2003. When the producible oil from the Sable field is depleted, most likely during 2009, production from the field's associated gas cap will be tied in to SCG and significantly enhance gas sales volumes.

PRODUCTION GROWTH

CANADA

Pioneer's activities in Canada are currently centered in two areas, the Chinchaga field, which straddles the border between northern British Columbia and Alberta, and the Horseshoe Canyon CBM play in south central Alberta. Our annual production from Canada rose 18% during 2006, supported by an aggressive Horseshoe Canyon CBM drilling program and a typical winter-access drilling schedule in the Chinchaga field.

Pioneer drilled approximately 150 CBM wells in the Horseshoe Canyon field during 2006 and plans to complete the tie-in of the last 40 of these wells in early 2007. Each of these wells is drilled in a matter of days, and with year-round access to the field, we plan to consider the outlook for North American natural gas prices before establishing our Horseshoe Canyon drilling program for the last half of 2007.

During 2007, we plan to maintain a 50-well pace in our winter-access areas where Pioneer has more than ten years of historical success in adding new production, expanding proved reserves and providing ongoing opportunity for future growth.

"Tangible progress was visible throughout the Canadian division in 2006. The solid production increases and reserve additions reflect the Canadian staff's considerable effort and commitment to success."

Todd Dillabough
President – Pioneer Canada

2006 10-K

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

FORM 10-K

/x/ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2006
or

/ / TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 1-13245

Pioneer Natural Resources Company

(Exact name of registrant as specified in its charter)

Delaware	**75-2702753**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
5205 N. O'Connor Blvd., Suite 200, Irving, Texas	**75039**
(Address of principal executive offices)	*(Zip Code)*

Registrant's telephone number, including area code: (972) 444-9001

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

Title of each class	**Name of each exchange on which registered**
Common Stock..	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 _x_ 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 _x_

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 _x_ 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 or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer _x_ Accelerated filer ___ Non-accelerated filer ___

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter	**$**	**5,732,341,639**
Number of shares of Common Stock outstanding as of February 13, 2007		**123,502,029**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held during May 2007 — Referenced in Part III of this report.

TABLE OF CONTENTS

		Page
Cautionary Statement Concerning Forward-Looking Statements		3
Definitions of Certain Terms and Conventions Used Herein		4
	PART I	
Item 1.	Business	5
	General	5
	Available Information	5
	Mission and Strategies	5
	Business Activities	6
	Operations by Geographic Area	8
	Marketing of Production	8
	Competition, Markets and Regulations	8
Item 1A.	Risk Factors	10
Item 1B.	Unresolved Staff Comments	15
Item 2.	Properties	15
	Proved Reserves	16
	Description of Properties	18
	Selected Oil and Gas Information	25
Item 3.	Legal Proceedings	32
Item 4.	Submission of Matters to a Vote of Security Holders	32
	PART II	
Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	33
	Purchases of Equity Securities by the Issuer and Affiliated Purchasers	33
Item 6.	Selected Financial Data	34
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	36
	Strategic Initiatives and Goals	36
	Financial and Operating Performance	36
	2007 Outlook and Activities	37
	Acquisitions	38
	Divestitures	38
	Results of Operations	39
	Capital Commitments, Capital Resources and Liquidity	47
	Critical Accounting Estimates	52
	New Accounting Pronouncements	55
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	56
	Quantitative Disclosures	56
	Qualitative Disclosures	60
Item 8.	Financial Statements and Supplementary Data	63
	Index to Consolidated Financial Statements	63
	Report of Independent Registered Public Accounting Firm	64
	Consolidated Financial Statements	65
	Notes to Consolidated Financial Statements	71
	Unaudited Supplementary Information	109
Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	115
Item 9A.	Controls and Procedures	115

Item 9B.	Other Information	117

PART III

Item 10.	Directors, Executive Officers and Corporate Governance	117
Item 11.	Executive Compensation	117
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	117
Item 13.	Certain Relationships and Related Transactions, and Director Independence	118
Item 14.	Principal Accounting Fees and Services	118

PART IV

Item 15.	Exhibits, Financial Statement Schedules	119

Cautionary Statement Concerning Forward-Looking Statements

Parts I and II of this annual report on Form 10-K (the "Report") contain forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to Pioneer Natural Resources Company ("Pioneer" or the "Company") or its management are intended to identify forward-looking statements. The forward-looking statements are based on the Company's current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See "Item 1. Business — Competition, Markets and Regulations", "Item 1A. Risk Factors" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for a description of various factors that could materially affect the ability of Pioneer to achieve the anticipated results described in the forward-looking statements. The Company undertakes no duty to publicly update these statements except as required by law.

Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

- *"Bbl"* means a standard barrel containing 42 United States gallons.
- *"Bcf"* means one billion cubic feet.
- *"BOE"* means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or natural gas liquid.
- *"BOEPD"* means BOE per day.
- *"Btu"* means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- *"CBM"* means coal bed methane.
- *"field fuel"* means gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.
- *"GAAP"* means accounting principles that are generally accepted in the United States of America.
- *"LIBOR"* means London Interbank Offered Rate, which is a market rate of interest.
- *"MBbl"* means one thousand Bbls.
- *"MBOE"* means one thousand BOEs.
- *"Mcf"* means one thousand cubic feet and is a measure of natural gas volume.
- *"MMBbl"* means one million Bbls.
- *"MMBOE"* means one million BOEs.
- *"MMBtu"* means one million Btus.
- *"MMcf"* means one million cubic feet.
- *"NGL"* means natural gas liquid.
- *"NYMEX"* means the New York Mercantile Exchange.
- *"NYSE"* means the New York Stock Exchange.
- *"Pioneer"* or the *"Company"* means Pioneer Natural Resources Company and its subsidiaries.
- *"proved reserves"* mean the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, *i.e.*, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

  (i) 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 (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) 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.

  (ii) 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.

  (iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics or economic factors; (C) crude oil, natural gas and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.
- *"SEC"* means the United States Securities and Exchange Commission.
- *"Standardized Measure"* means the after-tax present value of estimated future net revenues of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs in effect at the specified date and a 10 percent discount rate.
- *"VPP"* means volumetric production payment.
- *"U.S."* means United States.
- With respect to information on the working interest in wells, drilling locations and acreage, *"net"* wells, drilling locations and acres are determined by multiplying *"gross"* wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.
- Unless otherwise indicated, all currency amounts are expressed in U.S. dollars.

PART I

ITEM 1. BUSINESS

General

Pioneer is a Delaware corporation whose common stock is listed and traded on the NYSE. The Company is a large independent oil and gas exploration and production company with current operations in the United States, Canada, Equatorial Guinea, Nigeria, South Africa and Tunisia.

The Company's executive offices are located at 5205 N. O'Connor Blvd., Suite 200, Irving, Texas 75039. The Company's telephone number is (972) 444-9001. The Company maintains other offices in Anchorage, Alaska; Denver, Colorado; Midland, Texas; Calgary, Canada; London, England; Lagos, Nigeria; Capetown, South Africa and Tunis, Tunisia. At December 31, 2006, the Company had 1,624 employees, 924 of whom were employed in field and plant operations.

Available Information

Pioneer files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The public may read and copy any materials that Pioneer files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including Pioneer, that file electronically with the SEC. The public can obtain any documents that Pioneer files with the SEC at http://www.sec.gov.

The Company also makes available free of charge through its internet website (www.pxd.com) its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC.

Mission and Strategies

The Company's mission is to enhance shareholder investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline. These strategies are anchored by the Company's long-lived Spraberry oil field and Hugoton, Raton and West Panhandle gas fields which have an estimated remaining productive life in excess of 40 years. Underlying these fields are approximately 89 percent of the Company's proved oil and gas reserves as of December 31, 2006.

Strategic initiatives and goals. During 2006, the Company accomplished significant goals underlying the strategic initiatives established in 2005 to enhance shareholder value and investment returns. Specifically, the Company (i) essentially completed its $1 billion share repurchase program, (ii) successfully divested its deepwater Gulf of Mexico and Argentina assets at attractive valuations, (iii) allocated and focused its investment capital more heavily towards predictable oil and gas basins in North America that delivered strong production growth and (iv) lowered its risk profile by expanding North American unconventional resource investments while reducing higher-risk exploration expenditures.

2007 Plans. During 2007, the Company plans to: (i) grow production by 10 percent or more, anchored by continued low-risk development drilling in the Spraberry oil and Raton gas fields, (ii) commence production at the South Coast Gas project in South Africa in the second half of 2007, (iii) complete the construction and installation of facilities at the Company's Alaskan Oooguruk project and initiate drilling in late 2007, with first production in 2008, (iv) progress development of the Tunisian and Edwards Trend resource plays into production and reserve growth areas, (v) advance several other unconventional resource plays initiated during 2006, (vi) selectively explore for and develop proved reserves in areas that it believes will offer superior reserve growth and profitability potential; (vii) evaluate opportunities to acquire oil and gas properties that will complement the Company's exploration and development drilling activities; (viii) invest in the personnel and technology necessary to maximize the Company's exploration and development successes; and (ix) maintain liquidity, allowing the Company to take advantage of future exploration, development and acquisition opportunities.

Business Activities

The Company is an independent oil and gas exploration and production company. Pioneer's purpose is to competitively and profitably explore for, develop and produce oil, NGL and gas reserves. In so doing, the Company sells homogenous oil, NGL and gas units which, except for geographic and relatively minor quality differences, cannot be significantly differentiated from units offered for sale by the Company's competitors. Competitive advantage is gained in the oil and gas exploration and development industry by employing experienced management and staff that will lead the Company to prudent capital investment decisions, technological innovation and price and cost management.

Petroleum industry. For the last several years the petroleum industry has generally been characterized by volatile oil, NGL and gas commodity prices. During 2006, the Company's performance was also impacted by increasing costs, particularly higher drilling and well servicing rig rates and drilling supplies. During recent years, world oil prices increased in response to increases in demand from Asian economies and the perceived threat of supply disruptions in the Middle East, Nigeria, Venezuela and other areas. In 2006, oil prices initially increased due to supply uncertainty surrounding Middle East conflicts and then later decreased on moderating world demand and the easing of world tension, especially in the Middle East. North American gas prices fell in 2006 as a result of increased North American drilling and production, a very mild start to winter and a very large gas inventory overhang. Significant factors that will impact 2007 commodity prices include developments in the issues currently impacting Iraq and Iran and the Middle East in general; the extent to which members of the Organization of Petroleum Exporting Countries ("OPEC") and other oil exporting nations are able to continue to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals, including the impact of increasing liquefied natural gas ("LNG") deliveries to the United States.

To mitigate the impact of commodity price volatility on the Company's net asset value, Pioneer utilizes commodity hedge contracts. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the impact to oil and gas revenues during 2006, 2005 and 2004 from the Company's hedging activities and the Company's open hedge positions at December 31, 2006.

The Company. The Company's asset base is anchored by the Spraberry oil field located in West Texas, the Hugoton gas field located in Southwest Kansas, the Raton gas field located in southern Colorado and the West Panhandle gas field located in the Texas Panhandle. Complementing these areas, the Company has exploration and development opportunities and/or oil and gas production activities in the Gulf of Mexico, the onshore Gulf Coast area and Alaska, and internationally in Canada, Equatorial Guinea, Nigeria, South Africa and Tunisia. Combined, these assets create a portfolio of resources and opportunities that are well balanced among oil, NGLs and gas, and that are also well balanced between long-lived, dependable production, lower-risk exploration and development opportunities and a limited number of higher-impact exploration opportunities. Additionally, the Company has a team of dedicated employees that represent the professional disciplines and sciences that will allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

The Company provides administrative, legal, financial and management support to United States and foreign subsidiaries that explore for, develop and produce oil, NGL and gas reserves. Production operations are principally located domestically in Texas, Kansas, Colorado, Louisiana, Utah and the Gulf of Mexico, and internationally in Canada, South Africa and Tunisia.

Production. The Company focuses its efforts towards maximizing its average daily production of oil, NGLs and gas through development drilling, production enhancement activities and acquisitions of producing properties while minimizing the controllable costs associated with the production activities. During the year ended December 31, 2006, the Company's average daily production, on a BOE basis, decreased as a result of (i) initiation of oil deliveries in January 2006 associated with certain VPP transactions completed in 2005, which reduced the Company's reported production and (ii) production decreases in the Company's Sable oil field in South Africa and the Adam Concession oil field in Tunisia. Partially offsetting the decreases in production volumes were increases in oil production in the Spraberry field and gas production from the Raton field and Canada as part of the Company's aggressive 2006 drilling program. Excluding the delivery of the VPP volumes in 2006 (5.6 MMBOE) and 2005 (2.5 MMBOE), the Company's North American production increased approximately nine percent, which the Company believes provides a better understanding of the actual results of the Company's 2006 North American drilling program excluding the increased scheduled VPP deliveries. Production, price and cost information with respect to the Company's properties for 2006, 2005 and 2004 is set forth under "Item 2. Properties — Selected Oil and Gas Information — Production, Price and Cost Data".

Development activities. The Company seeks to increase its oil and gas reserves, production and cash flow through development drilling and by conducting other production enhancement activities, such as well recompletions. During the three years ended December 31, 2006, the Company drilled 2,346 gross (2,159 net) wells, 94 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $3.0 billion.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2006 include proved undeveloped reserves and proved developed reserves that are behind pipe of 202 MMBbls of oil and NGLs and 1,082 Bcf of gas. Development of these proved reserves will require future capital expenditures. The timing of the development of these reserves will be dependent upon the commodity price environment, the Company's expected operating cash flows and the Company's financial condition. The Company believes that its current portfolio of proved reserves and unproved prospects provides attractive development and exploration opportunities for at least the next three to five years.

Exploratory activities. The Company has devoted significant efforts and resources to hiring and developing a highly skilled exploration staff as well as acquiring a portfolio of lower-risk exploration opportunities complemented by a limited number of higher-impact exploration opportunities. During 2006, the Company divested substantially all of its assets in the deepwater Gulf of Mexico and Argentina and focused its exploration efforts towards lower-risk onshore North America and Africa opportunities. In the 2007 capital spending budget, the Company expects to spend approximately 20 percent of its $1.1 billion capital budget to test and develop lower-risk resource plays in onshore North America and Tunisia, and another five percent for high-impact exploration in the U.S. (principally Alaska) and West Africa. Exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons than development drilling or enhanced recovery activities. See "Item 1A. Risk Factors — Drilling activities" below.

Acquisition activities. The Company regularly seeks to acquire properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. In addition, the Company pursues strategic acquisitions that will allow the Company to expand into new geographical areas that feature producing properties and provide exploration/exploitation opportunities. During 2006, 2005 and 2004, the Company invested $223.2 million, $272.9 million and $2.6 billion, respectively, of acquisition capital to purchase proved oil and gas properties, including additional interests in its existing assets, and to acquire new prospects for future exploitation and exploration activities. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Company's acquisitions during 2006, 2005 and 2004.

The Company periodically evaluates and pursues acquisition opportunities (including opportunities to acquire particular oil and gas assets and entities owning oil and gas assets and opportunities to engage in mergers, consolidations or other business combinations with such entities) and at any given time may be in various stages of evaluating such opportunities. Such stages may take the form of internal financial analysis, oil and gas reserve analysis, due diligence, the submission of an indication of interest, preliminary negotiations, negotiation of a letter of intent or negotiation of a definitive agreement. The success of any acquisition is uncertain and will depend on a number of factors, some of which are outside the Company's control. See "Item 1A. Risk Factors — Acquisitions".

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. While the Company generally does not dispose of assets solely for the purpose of reducing debt, such dispositions can have the result of furthering the Company's objective of increasing financial flexibility through reduced debt levels. See Notes N, T and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's asset divestitures, VPPs and discontinued operations during 2006, 2005 and 2004.

The Company anticipates that it will continue to sell nonstrategic properties or other assets from time to time to increase capital resources available for other activities, to achieve operating and administrative efficiencies and to improve profitability.

Operations by Geographic Area

The Company operates in one industry segment, that being oil and gas exploration and production. See Note R of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for geographic operating segment information, including results of operations and segment assets.

Marketing of Production

General. Production from the Company's properties is marketed using methods that are consistent with industry practices. Sales prices for oil, NGL and gas production are negotiated based on factors normally considered in the industry, such as the index or spot price for gas or the posted price for oil, price regulations, distance from the well to the pipeline, well pressure, estimated reserves, commodity quality and prevailing supply conditions. See "Qualitative Disclosures" in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of operations and price risk.

Significant purchasers. During 2006, the Company's significant purchasers of oil, NGLs and gas were Oneok Resources (12 percent), Plains Marketing LP (12 percent) and Occidental Energy Marketing, Inc. (11 percent). The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on its ability to sell its oil, NGL and gas production.

Hedging activities. The Company, from time to time, utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the cash flow to fund the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's hedging activities, "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact on oil and gas revenues during 2006, 2005 and 2004 from commodity hedging activities and the Company's open and terminated commodity hedge positions at December 31, 2006.

Competition, Markets and Regulations

Competition. The oil and gas industry is highly competitive. A large number of companies, including major integrated and other independent companies, and individuals engage in the exploration for and development of oil and gas properties, and there is a high degree of competition for oil and gas properties suitable for development or exploration. Acquisitions of oil and gas properties have been an important element of the Company's growth. The Company intends to continue to acquire oil and gas properties that complement its operations, provide exploration and development opportunities and potentially provide superior returns on investment. The principal competitive factors in the acquisition of oil and gas properties include the staff and data necessary to identify, evaluate and purchase such properties and the financial resources necessary to acquire and develop the properties. Higher recent commodity prices have increased the cost of properties available for acquisition. Many of the Company's competitors are substantially larger and have financial and other resources greater than those of the Company.

Markets. The Company's ability to produce and market oil, NGLs and gas profitably depends on numerous factors beyond the Company's control. The effect of these factors cannot be accurately predicted or anticipated. Although the Company cannot predict the occurrence of events that may affect these commodity prices or the degree to which these prices will be affected, the prices for any commodity that the Company produces will generally approximate current market prices in the geographic region of the production.

Governmental regulations. Enterprises that sell securities in public markets are subject to regulatory oversight by agencies such as the SEC and the NYSE. This regulatory oversight imposes on the Company the responsibility for establishing and maintaining disclosure controls and procedures that will ensure that material information relating to the Company and its consolidated subsidiaries is made known to the Company's management and that the financial statements and other information included in submissions to the SEC do not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made in such submissions not misleading. Compliance with some of these regulations is costly and regulations are subject to change or reinterpretation.

Oil and gas exploration and production operations are also subject to various types of regulation by local, state, federal and foreign agencies. Additionally, the Company's operations are subject to state conservation laws and regulations, including provisions for the unitization or pooling of oil and gas properties, the establishment of maximum rates of production from wells and the regulation of spacing, plugging and abandonment of wells. States and foreign governments also generally impose a production or severance tax with respect to the production and sale of oil and gas within their respective jurisdictions. The regulatory burden on the oil and gas industry increases the Company's cost of doing business and, consequently, affects its profitability.

Additional proposals and proceedings that might affect the oil and gas industry are considered from time to time by the United States Congress, the Federal Energy Regulatory Commission, state regulatory bodies, the courts and foreign governments. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on the Company's operations.

Environmental and health controls. The Company's operations are subject to numerous U.S. federal, state and local, as well as foreign laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental and health protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the type, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas or impose substantial liabilities for pollution resulting from oil and gas operations. The Company's inability to obtain these permits in a timely manner or at all could cause delays or otherwise negatively impact the Company's ability to implement its business plans. Failure to comply with these environmental laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that limit or prevent operations. Although the Company believes that compliance with U.S. and foreign environmental laws and regulations will not have a material adverse effect on its future results of operations or financial condition, risks of substantial costs and liabilities are inherent in oil and gas operations, and there can be no assurance that significant costs and liabilities will not be incurred or that curtailment in production or processing might not arise as a result of such compliance. Moreover, it is possible that other developments, such as stricter environmental laws and regulations or claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities.

In the U.S., the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons with respect to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances released at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Company generates wastes in the U.S., including hazardous wastes, that are subject to the federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by the Company's oil and gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes, and therefore be subject to more rigorous and costly operating and disposal requirements.

The Company currently owns or leases, and has in the past owned or leased, properties in the U.S. that for many years have been used for the exploration and production of oil and gas reserves. Although the Company has used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where such hydrocarbons or wastes have been taken for recycling or disposal. In addition, some of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under the Company's control. These properties and the hydrocarbons or wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove or remediate previously disposed wastes or property contamination or to perform remedial plugging operations to prevent future contamination.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as the Company, to prepare and implement spill prevention control plans, countermeasure plans and facility response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") amends certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act ("CWA"), and other statutes as they pertain to the prevention of and response to oil spills into navigable waters of the U.S. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial liability for the costs of removing a spill. OPA requires responsible parties to establish and maintain evidence of financial responsibility to cover removal costs and damages resulting from an oil spill. OPA calls for a financial responsibility of $35 million to cover pollution cleanup for offshore facilities. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground. The Company does not believe that the OPA, CWA or related state laws are any more burdensome to it than they are to other similarly situated oil and gas companies.

Many states in which the Company operates regulate naturally occurring radioactive materials ("NORM") and NORM wastes that are generated in connection with oil and gas exploration and production activities. NORM wastes typically consist of very low-level radioactive substances that become concentrated in pipes and production equipment. Certain state regulations require the testing of pipes and production equipment for the presence of NORM, the licensing of NORM-contaminated facilities and the careful handling and disposal of NORM wastes. The Company believes the regulation of NORM has minimal effect on its operations because the Company generates only small quantities of NORM on an annual basis.

The Company’s field operations in the U.S. involve the use of gas-fired compressors, which are subject to the federal Clean Air Act and analogous state laws governing the control and permitting of air emissions. The Company believes that it is in compliance with applicable permitting and control technology requirements of such laws and regulations; however, in the future, additional facilities could become subject to additional permitting, monitoring and pollution control requirements as compressor facilities are expanded.

The Company's operations outside of the U.S. are generally subject to similar foreign governmental controls relating to protection of the environment. The Company believes that compliance with the existing requirements of these foreign governmental bodies has not had a material adverse effect on the Company's operations.

ITEM 1A. RISK FACTORS

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities. Other risks are described in "Item 1. Business — Competition, Markets and Regulations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk". These risks are not the only risks facing the Company. The Company’s business could also be impacted by additional risks and uncertainties not currently known to the

Company or that it currently deems to be immaterial. If any of these risks actually occur, they could materially harm the Company's business, financial condition or results of operations and impair Pioneer's ability to implement business plans or complete development projects as scheduled. In that case, the market price of the Company's common stock could decline.

Commodity prices. The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on oil and gas prices. These prices are affected by the supply of and market for oil and gas and numerous other factors beyond the Company's control. Historically, oil and gas prices have been very volatile. A significant downward trend in commodity prices would have a material adverse effect on the Company's revenues, profitability and cash flow and could, under certain circumstances, result in a reduction in the carrying value of the Company's oil and gas properties and goodwill and the recognition of deferred tax asset valuation allowances or an increase in the Company's deferred tax asset valuation allowance, depending on the Company's tax attributes in each country in which it has activities. The Company makes price assumptions that are used for planning purposes, and a significant portion of the Company's operating expenses, including rent, salaries and noncancellable capital commitments, is largely fixed in nature. Accordingly, if commodity prices are below expectations, the Company's financial results are likely to be adversely and disproportionately affected because these expenses are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

Hedging activities. To reduce our exposure to fluctuations in oil and gas prices, we have entered into, and expect in the future to enter into, hedging arrangements for a portion of our oil and gas production. These hedging arrangements may expose us to risk of financial loss in certain circumstances, including when:

- production is less than the hedged volumes,
- the counterparty to the hedging contract defaults on their contract obligations, or
- the hedging arrangements limit the benefit the Company would otherwise receive from increases in oil and gas prices.

Drilling activities. Drilling involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be encountered. The cost of drilling, completing and operating wells is often uncertain and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions and shortages or delays in the delivery of equipment. The Company's future drilling activities may not be successful and, if unsuccessful, such failure could have an adverse effect on the Company's future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. The Company expects that it will continue to experience exploration and abandonment expense in 2007, although only five percent of the Company's 2007 capital budget is devoted to higher-risk exploratory projects. Increased levels of drilling activity in the oil and gas industry in recent periods have led to reduced availability, extended delivery times and increased costs of some drilling equipment, materials and supplies. The Company expects that these trends will continue in the foreseeable future and, if so, they may impact the Company's profitability, cash flow and ability to complete development projects as scheduled.

Unproved properties. At December 31, 2006, the Company carried unproved property costs of $210.3 million. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, contracts and permits appurtenant to such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize noncash charges in the earnings of future periods.

Acquisitions. Acquisitions of producing oil and gas properties have been a key element of the Company's growth. The Company's growth following the full development of its existing property base could be impeded if it is unable to acquire additional oil and gas reserves on a profitable basis. The success of any acquisition will depend on a number of factors, including the ability to estimate accurately the costs to develop the reserves, the recoverable volumes of reserves, rates of future production and future net revenues attainable from the reserves and the assessment of possible environmental liabilities. All of these factors affect whether an acquisition will ultimately generate cash flows sufficient to provide a suitable return on investment. Even though the Company performs a review of the properties it seeks to acquire that it believes is consistent with industry practices, such reviews are often limited in scope. As a result, among other risks, the Company's initial estimates of reserves may be subject to revision following acquisition, materially and adversely impacting the desired benefits of the acquisition.

Divestitures. The Company regularly reviews its property base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities and create organizational and operational efficiencies. Various factors could materially affect the ability of the Company to dispose of nonstrategic assets, including the availability of purchasers willing to purchase the nonstrategic assets at prices acceptable to the Company. Sellers typically retain certain liabilities or indemnify buyers for certain matters. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material.

Goodwill. At December 31, 2006, the Company carried goodwill of $309.9 million associated with its United States reporting unit. Goodwill is tested for impairment at least annually, requiring an estimate of the fair values of the Company's assets and liabilities. If the fair value of the Company's net assets is not sufficient to fully support the goodwill balance, the Company will recognize noncash charges in the earnings of future periods.

Operation of gas processing plants. As of December 31, 2006, the Company owned interests in seven gas processing plants and seven treating facilities. The Company operates five of the plants and all seven treating facilities. There are significant risks associated with the operation of gas processing plants. Gas and NGLs are volatile and explosive and may include carcinogens. Damage to or misoperation of a gas processing plant or facility could result in an explosion or the discharge of toxic gases, which could result in significant damage claims in addition to interrupting a revenue source. For example, in May 2005, the Company's Fain gas plant was shut in for two months due to a mechanical failure that resulted in a fire.

Operating hazards and uninsured losses. The Company's operations are subject to all the risks normally incident to the oil and gas exploration and production business, including blowouts, cratering, explosions, adverse weather effects and pollution and other environmental damage, any of which could result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities or other property, clean-up responsibilities, regulatory investigations and penalties and suspension of operations. Increased hurricane activity in 2005 and 2004 resulted in production curtailments and physical damage to the Company's Gulf of Mexico operations. Although the Company currently maintains insurance coverage that it considers reasonable and that is similar to that maintained by comparable companies in the oil and gas industry, it is not fully insured against certain of the risks described in this paragraph, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance. Additionally, the Company relies to a large extent on facilities owned and operated by third-parties, and damage to or destruction of those third-party facilities could affect the ability of the Company to produce, transport and sell its hydrocarbons.

Environmental. The oil and gas business is subject to environmental hazards, such as oil spills, produced water spills, gas leaks and ruptures and discharges of substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. A variety of United States federal, state and local, as well as foreign laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to administrative, civil or criminal penalties, remedial cleanups, and natural resource damages or other liabilities, and compliance with these laws and regulations may increase the cost of the Company's operations. Such laws and regulations may also affect the costs of acquisitions. See "Item 1. Business — Competition, Markets and Regulations — Environmental and health controls" above for additional discussion related to environmental risks.

The Company does not believe that its environmental risks are materially different from those of comparable companies in the oil and gas industry. Nevertheless, no assurance can be given that future environmental laws will not result in a curtailment of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or adversely affect the Company's future operations and financial condition. Pollution and similar environmental risks generally are not fully insurable.

Impact of Weather and Climate. Demand for oil and natural gas are, to a significant degree, dependent on weather and climate, which impacts the price the Company receives for its production. In addition the Company's production, exploration and development activities and equipment can be adversely affected by severe weather, which may cause a loss of production from temporary cessation of activity or lost or damaged equipment, or unseasonal climate, which may delay or otherwise disrupt drilling and production schedules. Not all such effects can be predicted, eliminated or insured against.

Debt restrictions and availability. The Company is a borrower under fixed rate senior notes and a variable rate credit facility. The terms of the Company's borrowings under the senior notes and the credit facility specify scheduled debt repayments and require the Company to comply with certain associated covenants and restrictions. The Company's ability to comply with the debt repayment terms, associated covenants and restrictions is dependent on, among other things, factors outside the Company's direct control, such as commodity prices and interest rates. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt as of December 31, 2006 and the terms associated therewith.

The Company's ability to obtain additional financing is also impacted by the Company's debt credit ratings and competition for available debt financing. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of the Company's debt credit ratings.

Competition. The oil and gas industry is highly competitive. The Company competes with other companies, producers and operators for acquisitions and in the exploration, development, production and marketing of oil and gas. Some of these competitors have substantially greater financial and other resources than the Company. See "Item 1. Business — Competition, Markets and Regulations" above for additional discussion regarding competition.

Key personnel. Our business depends to a significant extent upon the continued service and performance of a relatively small number of key senior managers and technical personnel. The loss of any existing key personnel, or the inability to attract, motivate and retain additional key personnel, could harm our business, financial condition and results of operations.

Government regulation. The Company's business is regulated by a variety of federal, state, local and foreign laws and regulations. There can be no assurance that present or future regulations will not adversely affect the Company's business and operations. See "Item 1. Business — Competition, Markets and Regulations" above for additional discussion regarding government regulation.

International operations. At December 31, 2006, approximately five percent of the Company's proved reserves of oil, NGLs and gas were located outside the United States (three percent in Canada and two percent in Africa). The success and profitability of international operations may be adversely affected by risks associated with international activities, including economic and labor conditions, political instability, tax laws (including host-country import-export, excise and income taxes and United States taxes on foreign subsidiaries) and changes in the value of the U.S. dollar versus the local currencies in which oil and gas producing activities may be denominated. In some cases, the market for the Company's production in foreign countries is limited to some extent. For example, all of the Company's gas and condensate production from the South Coast Gas project is currently committed by contract to a single, government-affiliated gas-to-liquids facility. If such facility ceased to purchase the gas because of an unforeseen event excusing performance, it might be difficult to find an alternative market for the production, and if such a market were secured, the price received by the Company might be less than that provided under its current gas sales contract. See "Critical Accounting Estimates" included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations", "Qualitative Disclosures – Foreign currency, operations and price risk" in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding other risks associated with the Company's international operations.

Estimates of reserves and future net revenues. Numerous uncertainties exist in estimating quantities of proved reserves and future net revenues therefrom. The estimates of proved reserves and related future net revenues set forth in this Report are based on various assumptions, which may ultimately prove to be inaccurate.

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 the following:

- historical production from the area compared with production from other producing areas,
- the quality and quantity of available data,
- the interpretation of that data,
- the assumed effects of regulations by governmental agencies,
- assumptions concerning future oil and gas sales prices and
- assumptions concerning future operating costs, severance, ad valorem 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 production and operating costs incurred,
- the amount and timing of future development expenditures and
- future oil and gas sales prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The Company's actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are 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 cash flows also will be affected by factors such as:

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

The Company reports all proved reserves held under production sharing arrangements and concessions utilizing the "economic interest" method, which excludes the host country's share of proved reserves. Estimated quantities of production sharing arrangements reported under the "economic interest" method are subject to fluctuations in the price of oil and gas and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and gas companies subject to the rules and regulations of the SEC. It requires the use of oil and gas prices, as well as operating and development costs, prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and gas production because of seasonal price fluctuations or other varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and gas properties. Accordingly, estimates included herein of future net revenues may be materially different from the net revenues that are ultimately received. Therefore, the estimates of discounted future net cash flows or

Standardized Measure in this Report should not be construed as accurate estimates of the current market value of the Company's proved reserves.

Production forecasts. From time to time the Company provides forecasts of expected quantities of future oil and gas production. These forecasts are based on a number of estimates, including expectations of production decline rates from existing wells and the outcome of future drilling activity. Should these estimates prove inaccurate, actual production could be adversely impacted. Downturns in commodity prices could make certain drilling activities or production uneconomical, which would also adversely impact production.

Stock repurchases. The Board of Directors (the "Board") approves share repurchase programs and sets limits on the price per share at which Pioneer's common stock can be repurchased. The Company is not permitted to repurchase its stock during certain periods because of scheduled and unscheduled trading blackouts. Additionally, business conditions and availability of capital may dictate that repurchases be suspended or canceled. As a result, there can be no assurance that additional repurchases will be commenced and, if so, that they will be completed.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The information included in this Report about the Company's proved reserves as of December 31, 2006, 2005 and 2004, which were located in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations prepared by the Company's engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI") with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. The reserve audits performed by NSAI in aggregate represented 89 percent, 82 percent and 88 percent of the Company's 2006, 2005 and 2004 proved reserves, respectively; and, 83 percent, 76 percent and 84 percent of the Company's 2006, 2005 and 2004 associated pre-tax present value of proved reserves discounted at ten percent, respectively.

NSAI follows the general principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserve information promulgated by the Society of Petroleum Engineers ("SPE"). A reserve audit as defined by the SPE is not the same as a financial audit. The SPE's definition of a reserve audit includes the following concepts:

- A reserve audit is an examination of reserve information that is conducted for the purpose of expressing an opinion as to whether such reserve information, in the aggregate, is reasonable and has been presented in conformity with generally accepted petroleum engineering and evaluation principles.

- The estimation of proved reserves is an imprecise science due to the many unknown geologic and reservoir factors that cannot be estimated through sampling techniques. Since reserves are only estimates, they cannot be audited for the purpose of verifying exactness. Instead, reserve information is audited for the purpose of reviewing in sufficient detail the policies, procedures and methods used by a company in estimating its reserves so that the reserve auditors may express an opinion as to whether, in the aggregate, the reserve information furnished by a company is reasonable and has been estimated and presented in conformity with generally accepted petroleum engineering and evaluation principles.

- The methods and procedures used by a company, and the reserve information furnished by a company, must be reviewed in sufficient detail to permit the reserve auditor, in its professional judgment, to express an opinion as to the reasonableness of the reserve information. The auditing procedures require the reserve auditor to prepare its own estimates of reserve information for the audited properties.

To further clarify, in conjunction with the audits of the Company's proved reserves and associated pre-tax present value discounted at ten percent, the Company provided to NSAI its external and internal engineering and geoscience technical data and analyses. Following NSAI's review of that data, it had the option of honoring the Company's interpretation, or making its own interpretation. No data was withheld from NSAI. NSAI accepted without independent verification the accuracy and completeness of the historical information and data furnished by the Company with respect to ownership interest; oil and gas production; well test data; oil, NGL and gas prices; operating and development costs; and any agreements relating to current and future operations of the properties and sales of production. However, if in the course of its evaluation something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved its questions relating thereto or had independently verified such information or data.

In the course of its evaluations, NSAI prepared, for all of the audited properties, its own estimates of the Company's proved reserves and pre-tax present value of such reserves discounted at ten percent. NSAI's estimates of those proved reserves and pre-tax present value of such reserves discounted at ten percent did not differ from the Company's estimates by more than ten percent in the aggregate. However, when compared on a field-by-field or area-by-area basis, some of the Company's estimates were greater than those of NSAI and some were less than the estimates of NSAI. When such differences did not exceed ten percent in the aggregate and NSAI was satisfied that the proved reserves and pre-tax present value of such reserves discounted at ten percent were reasonable and that its audit objectives had been met, NSAI issued a completed unqualified audit opinion. Remaining differences were not resolved due to the limited cost benefit of continuing such analyses by the Company and NSAI. At the conclusion of the audit process, it was NSAI's opinion, as set forth in its audit letters, that Pioneer's estimates of the Company's proved oil and gas reserves and associated pre-tax future net revenues discounted at ten percent are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

The Company did not provide estimates of total proved oil and gas reserves during 2006, 2005 or 2004 to any federal authority or agency, other than the SEC. The Company's reserve estimates do not include any probable or possible reserves. Also, see "Item 1A. Risk Factors" and "Critical Accounting Estimates" in "Item 7. Management's Discussion and Analysis and Results of Operations" for additional discussions regarding proved reserves and their related cash flows.

Proved Reserves

The Company's proved reserves totaled 904.9 MMBOE, 986.7 MMBOE and 1.0 billion BOE at December 31, 2006, 2005 and 2004, respectively, representing $4.7 billion, $7.3 billion and $6.6 billion, respectively, of Standardized Measure. The Company's proved reserves include field fuel, which is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point. The following table shows the changes in the Company's proved reserve volumes by geographic area during the year ended December 31, 2006 (in MBOE):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
United States	(36,499)	34,733	50,543	(29,395)	(9,244)
Argentina	(3,743)	898	—	(97,920)	(646)
Canada	(2,924)	11,351	—	—	(1,485)
South Africa	(1,506)	—	—	—	1,541
Tunisia	(943)	1,870	—	—	1,588
Total	(45,615)	48,852	50,543	(127,315)	(8,246)

Production. Production volumes include 2,894 MBOE of field fuel and 6,811 MBOE of production associated with divested assets being presented as discontinued operations.

Extensions and discoveries. Extensions and discoveries are primarily the result of extension drilling in the Raton field and Spraberry field in the United States and the Horseshoe Canyon field in Canada and lower-risk exploratory drilling in the Company's South Texas Edwards Trend and Tunisian resource plays.

Purchases of minerals-in-place. Purchases of minerals-in-place are primarily attributable to bolt-on acquisitions and joint venture activities in the Company's Spraberry field and Edwards Trend area.

Sales of minerals-in-place. Sales of minerals-in-place are principally related to the Company's divestiture of its deepwater Gulf of Mexico and Argentine assets during 2006. See Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

Revisions of previous estimates. Revisions of previous estimates are comprised of 14 MMBOE of negative price revisions offset by 6 MMBOE of positive technical revisions. The Company's proved reserves at December 31, 2006 were determined using year-end NYMEX equivalent prices of $60.82 per barrel of oil and $5.64 per Mcf of gas, compared to $61.04 per barrel of oil and $10.08 per Mcf of gas at December 31, 2005. The lower gas prices at December 31, 2006 decreased the economic life on certain gas properties, the majority of which were in the Raton gas field.

On a BOE basis, 60 percent of the Company's total proved reserves at December 31, 2006 were proved developed reserves. Based on reserve information as of December 31, 2006, and using the Company's production information for the year then ended, excluding production associated with divested assets included in discontinued operations, the reserve-to-production ratio associated with the Company's proved reserves was in excess of 20 years on a BOE basis. The following table provides information regarding the Company's proved reserves and average daily sales volumes by geographic area as of and for the year ended December 31, 2006:

	Proved Reserves as of December 31, 2006				**2006 Average Daily Sales Volumes (b)**		
	Oil & NGLs (MBbls)	**Gas (MMcf) (a)**	**MBOE**	**Standardized Measure (in thousands)**	**Oil & NGLS (Bbls)**	**Gas (Mcf)**	**BOE**
United States....	406,725	2,685,961	854,385	$ 4,189,171	36,204	284,732	83,659
Canada............	2,199	173,509	31,117	269,289	774	43,420	8,011
South Africa	3,070	60,511	13,156	143,722	4,127	—	4,127
Tunisia............	4,977	7,846	6,284	86,807	2,386	1,195	2,585
Total	416,971	2,927,827	904,942	$ 4,688,989	43,491	329,347	98,382

(a) The gas reserves contain 316,528 MMcf of gas that will be produced and utilized as field fuel.

(b) The 2006 average daily sales volumes are from continuing operations and (i) do not include the field fuel produced, which averaged 47,568 Mcf per day, and (ii) were calculated using a 365-day year and without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the year.

The following table represents the estimated timing and cash flows of developing the Company's proved undeveloped reserves as of December 31, 2006 (dollars in thousands):

Year Ended December 31, (a)	Estimated Future Production (MBOE)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
2007	4,481	$ 175,426	$ 24,487	$ 589,438	$ (438,499)
2008	10,127	389,933	61,873	691,380	(363,320)
2009	15,803	611,695	100,032	572,748	(61,085)
2010	19,240	741,831	128,291	475,130	138,410
Thereafter	312,710	12,893,943	3,465,588	1,331,388	8,096,967
	362,361	$ 14,812,828	$ 3,780,271	$ 3,660,084	$ 7,372,473

(a) Beginning in 2008 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling since 2007.

Description of Properties

United States

Approximately 89 percent of the Company's proved reserves at December 31, 2006 are located in the Spraberry field in the Permian Basin area, the Hugoton and West Panhandle fields in the Mid-Continent area and the Raton field in the Rocky Mountains area. These fields generate substantial operating cash flow and the Spraberry and Raton fields have a large portfolio of low-risk drilling opportunities. The cash flows generated from these fields provide funding for the Company's other development and exploration activities both domestically and internationally.

The following tables summarize the Company's United States development and exploration/extension drilling activities during 2006:

	Development Drilling					
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Divested Wells	Ending Wells In Progress
Permian Basin	27	313	327	3	—	10
Mid-Continent	—	43	41	1	—	1
Rocky Mountains	—	289	281	3	—	5
Onshore Gulf Coast	2	14	13	1	—	2
Total United States	29	659	662	8	—	18

	Exploration/Extension Drilling					
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Divested Wells	Ending Wells In Progress
Permian Basin	—	16	14	1	—	1
Rocky Mountains	1	32	17	—	—	16
Gulf of Mexico:						
Continuing operations	—	2	1	1	—	—
Discontinued operations	3	-	3	—	—	—
Onshore Gulf Coast	—	21	14	3	—	4
Alaska	3	3	3	3	—	—
Total United States	7	74	52	8	—	21

The following tables summarize by geographic area the Company's United States costs incurred during 2006:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
	(in thousands)					
Permian Basin	$ 51,421	$ 30,703	$ 12,411	$ 285,980	$ 1,884	$ 382,399
Mid-Continent	133	—	156	35,759	2,650	38,698
Rocky Mountains	1,240	17,495	64,924	170,863	9,561	264,083
Gulf of Mexico:						
Continuing operations	—	8	94,167	5,045	6,028	105,248
Discontinued operations	—	2	3,808	3,167	—	6,977
Onshore Gulf Coast	19,743	33,157	82,775	61,705	1,396	198,776
Alaska	4,800	27,956	34,684	119,309 (a)	1,350	188,099
Total United States	$ 77,337	$ 109,321	$ 292,925	$ 681,828	$ 22,869	$ 1,184,280

(a) Includes $6.8 million of capitalized interest related to the Oooguruk project.

Permian Basin

Spraberry field. The Spraberry field was discovered in 1949 and encompasses eight counties in West Texas. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casinghead gas with an average energy content of 1,400 Btu. The oil and gas are produced primarily from three formations, the upper and lower Spraberry and the Dean, at depths ranging from 6,700 feet to 9,200 feet. In addition, the Company has started completing the majority of its wells in the Wolfcamp formation at depths ranging from 9,300 feet to 10,300 feet with successful results. The Company believes the Spraberry field offers excellent opportunities to enhance oil and gas production because of the numerous undeveloped drilling locations, many of which are reflected in the Company's proved undeveloped reserves, and the ability to contain operating expenses through economies of scale.

During 2006, the Company (a) drilled 299 wells, an increase of 118 wells over 2005, (b) acquired approximately 200,000 gross acres, bringing its total acreage position to approximately 684,000 gross acres (593,000 net acres), (c) completed several bolt-on property acquisitions and joint ventures, (d) successfully drilled a majority of the wells to the Wolfcamp formation and (e) acquired a well servicing operation as a measure to control costs.

Mid-Continent

Hugoton field. The Hugoton field in southwest Kansas is one of the largest producing gas fields in the continental United States. The gas is produced from the Chase and Council Grove formations at depths ranging from 2,700 feet to 3,000 feet. The Company's gas in the Hugoton field has an average energy content of 1,025 Btu. The Company's Hugoton properties are located on approximately 285,000 gross acres (247,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,200 wells in the Hugoton field, about 1,000 of which it operates, and partial royalty interests in approximately 500 wells. The Company owns substantially all of the gathering and processing facilities, primarily the Satanta plant, that service its production from the Hugoton field. Such ownership allows the Company to control the production, gathering, processing and sale of its gas and NGL production.

The Company's Hugoton operated wells are capable of producing approximately 69 MMcf of wet gas per day (i.e., gas production at the wellhead before processing or field fuel use and before reduction for royalties), although actual production in the Hugoton field is limited by allowables set by state regulators. The Company estimates that it and other major producers in the Hugoton field produced near allowable capacity during the year ended December 31, 2006.

During 2006, the Company reached a settlement agreement on the class action Alford royalty lawsuit which primarily revolved around costs being charged to the royalty owners. The settlement agreement provides for adjustment to the manner in which royalty payments will be calculated and accordingly, the Company expects a small increase in its production costs beginning in 2007. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

West Panhandle field. The West Panhandle properties are located in the panhandle region of Texas. These stable, long-lived reserves are attributable to the Red Cave, Brown Dolomite, Granite Wash and fractured Granite formations at depths no greater than 3,500 feet. The Company's gas in the West Panhandle field has an average energy content of 1,300 Btu and is produced from approximately 600 wells on more than 250,000 gross acres (240,000 net acres) covering over 375 square miles. The Company controls 100 percent of the wells, production equipment, gathering system and gas processing plant for the field.

The Company is pursuing regulatory relief in the West Panhandle field to allow for future additional drilling locations.

Rocky Mountains

Raton field. The Raton Basin properties are located in the southeast portion of Colorado. Exploration for CBM in the Raton Basin began in the late 1970s and continued through the late 1980s, with several companies drilling and testing more than 100 wells during this period. The absence of a pipeline to transport gas from the Raton Basin prevented full scale development until January 1995, when Colorado Interstate Gas Company completed the construction of the Picketwire lateral pipeline system. The Company's gas in the Raton Basin has an average energy content of 1,000 Btu. Since the completion of the Picketwire lateral, production has continued to grow, resulting in expansion of the system’s capacity by its operator, the most recent expansion of which was in October 2005. The Company owns approximately 317,000 gross acres (281,000 net acres) in the center of the Raton Basin with current production from coal seams of the Vermejo and Raton formations. The Company owns the well servicing and frac equipment that it utilizes in the Raton field to control costs and insure availability.

During 2006, the Company (a) drilled 288 wells, (b) added wellhead compression and (c) continued efforts to optimize gathering and compression facilities.

Piceance/Uinta Basins. The Piceance Basin is located in the central portion of western Colorado, and the Uinta Basin is located in the central portion of eastern Utah. The Company owns approximately 244,000 gross acres covering producing and prospective regions of the Piceance and Uinta Basins. Currently, production is established from various tight sandstone, coal and shale formations. The Company’s significant projects in the area are CBM plays at Columbine Springs and Castlegate and a deep gas play at Main Canyon.

At Columbine Springs, in northwest Colorado, the Company is completing its extension pilot program, with all wells expected to be on production by the end of the first quarter of 2007. If the pilot project is successful in achieving commercial quantities of gas production, full field development could begin in 2008.

In northeast Utah, the Company continues to monitor its CBM pilot at Castlegate and is testing the wells recently drilled in the Main Canyon area. An assessment of whether either project will be commercial is not expected until the second half of 2007.

Sand Wash Basin. The Sand Wash Basin is the site of a potential CBM project located north of the Company's Piceance Basin properties. The Company holds a 50 percent operated interest in 114,000 gross acres in the Lay Creek field. At Lay Creek, the Company has drilled 15 wells in five separate pilot areas and completed workovers and recompletions on 14 wells drilled by a previous operator. The Company has completed the water treatment facility and plans to initiate production in the first quarter of 2007. If the pilot projects are successful in achieving commercial quantities of gas production, full field development could begin in 2008.

Gulf of Mexico

Gulf of Mexico area. During March 2006, the Company sold all of its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $726.2 million. See Notes N and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the deepwater Gulf of Mexico divestiture.

During 2005, the Company announced a discovery on its Clipper prospect in the Green Canyon Blocks 299 and 300 in the deepwater Gulf of Mexico. During 2006, the Company drilled two successful Clipper appraisal wells, but drilled an unsuccessful exploratory well at the Flying Cloud prospect, a prospect near the Clipper discovery. The Company expects to develop the Clipper discovery and is currently evaluating sub-sea tie-back options to third-party production handling facilities in the area. Pioneer operates the Clipper discovery with a 55 percent working interest.

As a result of Hurricane Rita, the Company's East Cameron facility, located on the Gulf of Mexico shelf, was destroyed and the Company does not plan to rebuild the facility based on the economics of the field. During the fourth quarter of 2006, the Company's application to "reef in-place" a substantial portion of the East Cameron debris was denied. As a result, the Company currently estimates that it will cost approximately $119 million to reclaim and abandon the East Cameron facility. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis and fee proposal prepared by a third-party engineering firm for the majority of the work and an estimate by the Company for the remainder. During 2006 and 2005, the Company recorded additional abandonment obligation charges of $75.0 million and $39.8 million, respectively, which amounts are included in hurricane activity, net in the accompanying Consolidated Statements of Operations. The operations to reclaim and abandon the East Cameron facilities began in January 2007 and the Company expects to incur a substantial portion of the costs in 2007. The Company expects that a substantial portion of the total estimated cost to reclaim and abandon the facility will be covered by insurance, including 100 percent of the debris removal costs. Consequently, the Company has recorded a $43.0 million insurance recovery receivable corresponding to the estimated debris removal costs.

During 2006, the Company announced its intent to divest of its Gulf of Mexico shelf properties; however, the Company has decided not to divest of these properties after its sales efforts in 2006 did not result in an acceptable offer.

Onshore Gulf Coast

South Texas. The Company has historically focused its drilling efforts in South Texas on the Pawnee field in the Edwards Trend in South Texas. The Edwards Trend is a tight gas limestone reservoir characterized by narrow bands of dry gas fields extending over 250 miles. The Company has acquired over 270,000 gross acres in the Edwards Trend. In addition to the operations in the Pawnee field, the Company has operations in the SW Kenedy and Washburn fields. Production depths in the Edwards Trend range from 9,500 feet to 14,000 feet.

During 2006, the Company drilled 16 exploration and appraisal wells targeting new field discoveries in the Edwards Trend area with 88 percent success, exceeding expectations and increasing proved gas reserves. Eight new wells have been added to production and six wells are awaiting pipelines or testing.

Having 3-D seismic data has significantly enhanced field development in the Pawnee field, allowing the Company to more accurately locate and orient the horizontal wells for optimal results. To expand its 3-D data coverage to include new discoveries and additional prospects, the Company plans to shoot and interpret approximately 850 square miles of new data. Multiple surveys are planned for 2007, with three already underway. While the new seismic work is being completed, the Company will direct most of its investments in the Edwards Trend to lower-risk, lower-cost development drilling on existing discoveries where 3-D data is currently available.

To revitalize existing horizontal wells in the area, the Company has initiated a pilot using more extensive fracture stimulation techniques. Horizontal wells in the field are completed open-hole and have traditionally been lightly stimulated with acid. Recently, the Company began performing a new fracture stimulation procedure on additional wells. The Company plans to fracture stimulate additional horizontal wells, including newer producing wells, during 2007 to further evaluate the potential for a more extensive program. The Company also recently drilled a new horizontal well within a developed section of the Pawnee field with very successful results. The Company is currently evaluating additional infill drilling locations given this success. Plans are also in progress to expand the gas gathering infrastructure in the area to accommodate expected production growth and to maximize efficiency at the Company's Pawnee Plant.

Northern Louisiana and Mississippi. The Company has acquired significant acreage in Northern Louisiana and Mississippi. The Company has built an acreage position covering multiple plays in the Mississippi Salt Basin and now holds leases and option interests covering over 300,000 acres. Over the next two to three years, the Company expects to test a number of opportunities and to continue technical work that is currently underway.

One of the lower-risk opportunities in the portfolio is the redevelopment of the Bolton Gas Field in Hinds County, Mississippi. The first well of the project was drilled to 17,600 feet and penetrated multiple gas-bearing Cotton Valley sands. Currently, the well is being logged and completion design work is progressing. The location for the next well has been built and drilling will commence immediately after operations are completed on the current well. The Company plans to drill at least one more well in 2007 during this initial phase of the project. Facility construction is underway and first production is anticipated in mid-2007.

The Company has also concluded drilling operations on its first well testing the Norphlet formation in Mississippi. The well was drilled in Wayne County and, after extensive evaluation, has been plugged and abandoned. Future drilling plans will be determined after a technical analysis of the initial well is completed.

Alaska

Oooguruk. During 2002, the Company acquired a 70 percent working interest and operatorship in ten state leases on Alaska's North Slope. In connection therewith, the Company drilled three exploratory wells during 2003 to test a possible extension of the productive sands in the Kuparuk River field in the shallow waters offshore the North Slope of Alaska. Although all three of the wells found the sands filled with oil, they were too thin to be considered commercial on a stand-alone basis. However, the wells also encountered thick sections of oil-bearing Jurassic-aged sands, and the first well flowed at a rate of approximately 1,300 Bbls per day. In January 2004, the Company farmed-into a large acreage block to the southwest of the Company's discovery. In 2004, Pioneer completed an extensive technical and economic evaluation of the resource potential within this area. As a result of this evaluation, the Company performed front-end engineering and permitting activities during 2005 to further define the scope of the project. In early 2006, the Company announced that it had approved the development of the Oooguruk field in the project area.

The Company has constructed and armored the gravel drilling and production island site and installation of a sub-sea flowline and facilities are planned for 2007 to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit. The Company continues to procure equipment and services, fabricate equipment and modify a drilling rig for installation in 2007. Development drilling of approximately 40 wells on the project is expected to begin in late 2007 and be completed in 2009. First production is expected in 2008.

Cosmopolitan. During 2005, Pioneer announced that it entered into an agreement on the Cosmopolitan Unit in the Cook Inlet. Under this agreement, Pioneer earned a ten percent working interest in the unit from ConocoPhillips through a disproportionate spending arrangement for a 3-D seismic program undertaken during the fourth quarter of 2005. In June 2006, the Company exercised an option to acquire an additional 40 percent working interest in the Cosmopolitan Unit, bringing its working interest to 50 percent. Pioneer was elected operator of the Cosmopolitan Unit and plans to drill an appraisal well in 2007.

Onshore North Slope area. The Company holds a large acreage position in the onshore North Slope area of Alaska, primarily in the National Petroleum Reserve – Alaska (“NPRA”). During the 2006-2007 drilling season, the Company plans to participate in the drilling of two non-operated exploratory wells in the NPRA.

International

The Company's international operations are located in Canada, offshore South Africa and in southern Tunisia. Additionally, the Company has exploration activities West Africa (Equatorial Guinea and Nigeria). As of December 31, 2006, approximately three percent and two percent of the Company's proved reserves were located in Canada and Africa, respectively.

The following tables summarize the Company's international development and exploration/extension drilling activities during 2006:

	Development Drilling					
	Beginning Wells In Progress	**Wells Spud**	**Successful Wells**	**Unsuccessful Wells**	**Divested Wells**	**Ending Wells In Progress**
Argentina – discontinued operations	2	21	14	1	8	—
Canada	3	2	2	—	—	3
South Africa	—	4	2	—	—	2
Total International	5	27	18	1	8	5

	Exploration/Extension Drilling					
	Beginning Wells In Progress	**Wells Spud**	**Successful Wells**	**Unsuccessful Wells**	**Divested Wells**	**Ending Wells In Progress**
Argentina – discontinued operations	4	6	4	2	4	—
Canada	109	249	326	16	—	16
South Africa	1	—	—	1	—	—
Tunisia	2	7	2	2	—	5
West Africa - Nigeria	—	1	—	1	—	—
Total International	116	263	332	22	4	21

The following tables summarize by geographic area the Company's international costs incurred during 2006:

	Property Acquisition Costs					
	Proved	**Unproved**	**Exploration Costs**	**Development Costs**	**Asset Retirement Obligations**	**Total**
	(in thousands)					
Argentina—discontinued operations	$ —	$ 2	$ 10,223	$ 25,542	$ —	$ 35,767
Canada	—	19,932	103,245	97,188	8,299	228,664
South Africa	—	—	288	117,511 (a)	13,964	131,763
Tunisia	—	5,000	40,813	—	336	46,149
Other	—	—	11,358	—	—	11,358
West Africa:						
Equatorial Guinea	—	—	(1,688)	—	—	(1,688)
Nigeria	—	10,584	26,502	—	—	37,086
Total International	$ —	$ 35,518	$ 190,741	$ 240,241	$ 22,599	$ 489,099

(a) Includes $5.3 million of capitalized interest related to the South Coast Gas project.

Argentina. During April 2006, the Company sold its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. See Notes N and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Argentine divestiture.

Canada. The Company's Canadian producing properties are located primarily in Alberta and British Columbia, Canada. The Company continues to exploit lower-risk opportunities identified in the Chinchaga field in northeast British Columbia and Alberta. Production from the Chinchaga field is relatively dry gas from formation depths averaging 3,400 feet.

The Company has commenced production and continued significant drilling, pipeline and facility activities in south-central Alberta targeting Horseshoe Canyon CBM in the greater Drumheller area. The greater Drumheller area produces gas, condensate and minor oil from Cretaceous to Devonian formations at depths ranging from 400 to 6,500 feet.

Also, in southern Alberta the Company has initiated a CBM pilot in the Mannville coals. Currently, six wells have been drilled and are in the dewatering stages to see if commercial quantities of gas can be achieved. The Company is also evaluating other completion techniques that could potentially accelerate the dewatering and increase production rates.

South Africa. The Company has agreements to explore for oil and gas offshore South Africa covering over 3.6 million acres along the southern coast in water depths generally less than 650 feet. The Sable oil field began producing in August 2003 and the majority of the gas from the field has been reinjected. The Company has a 40 percent working interest in the Sable field.

In 2005, the Company sanctioned the non-operated South Coast Gas development project, which includes the sub-sea tie-back of gas from the Sable field and six additional gas accumulations to an existing production facility on the F-A platform for transportation via existing pipelines to a gas-to liquids plant. Pioneer has a 45 percent working interest in the project. As part of sanctioning of the South Coast Gas project, the Company signed a six-year contract for the sale of all of its gas and condensate production from the project. The contract contains an obligation for the purchaser to take or pay for a total of 91.4 BCF and associated condensate if the anticipated deliverability estimates are achieved. The price for both gas and condensate is indexed to Brent oil sales. During 2006, the Company drilled four wells. During the first half of 2007, the Company plans to drill two additional development wells and complete the sub-sea well tie-backs to the existing production facilities on the F-A platform. First production is expected to commence in the second half of 2007.

Tunisia. The Company’s Tunisian exploration permits can be separated into three categories: (i) two exploration permits (Jenein Nord and El Hamra) covering 1.6 million acres which the Company operates with a 100 percent working interest, (ii) the Anadarko-operated Anaguid exploration permit covering over 1.2 million acres in which the Company has a 45 percent working interest and (iii) the ENI-operated Adam Concession and Borj El Khadra exploration permit covering approximately 212,000 acres and 970,000 acres, respectively, in which the Company has a 20 percent and 40 percent working interest, respectively. All exploration permits and concessions are onshore southern Tunisia.

Production from the Adam Concession began in May 2003. During 2006, the Company continued its exploratory and appraisal activities on the Adam Concession by drilling four wells, of which three were successful, and completed a 3-D seismic survey. In 2006, the Company's interest in the Adam Concession was reduced from 24 percent to 20 percent in accordance with the terms of the concession. At December 31, 2006, the Company had an exploratory well in progress on each of the Adam Concession and Borj El Khadra block. Both wells were successful and are being added to production in the first quarter of 2007. The Company plans to drill an additional two to three wells in the concession during 2007.

In 2006, the Company acquired the remaining equity interest in the Jenein Nord block that it did not already own and became the operator of the block. During 2006, the Company completed a 3-D seismic survey on the Jenein Nord block. The Company drilled an exploratory well during 2006 that encountered multiple oil bearing zones and its commercial development is being analyzed. At December 31, 2006, the Company had an additional exploratory well in progress which was successful. The Company plans to drill one to two additional wells in the block during 2007. After the performance of the wells has been monitored for several months, additional exploration and appraisal wells may also be drilled.

Recently, the Company entered into a farm-out agreement of its interest in the El Hamra block pursuant to which it retained an economic interest in the block. In the Anaguid block, the Company continues to evaluate the results of its past drilling on the block and other blocks in the area to determine the go-forward plans on the block.

West Africa

The Company previously disclosed that it had retained a third party adviser to assist it in marketing its West Africa assets. No agreement to sell these assets has been reached to date, but the Company continues to consider interest from potential purchasers. As such, the capital budget includes amounts for expected drilling activities in West Africa during 2007. A first well is expected to spud during the second quarter of 2007, with drilling on a second well expected to commence in the second half of 2007, both in deepwater Nigeria. The timing of the drilling of a third well is uncertain and therefore no amounts have been budgeted for this prospect in 2007.

Equatorial Guinea. The Company owns a 50 percent working interest in Block H located in the northern Rio Muni Basin of Equatorial Guinea. The block covers an area of over 240,000 acres and water depth ranging from 300 meters in the southeastern corner of the block to over 1,800 meters near the western block boundary. Currently, as a result of new hydrocarbon law in Equatorial Guinea, the government in Equatorial Guinea is claiming an additional participation interest in the block. The Company is evaluating the effect of the claim with the operator of the block. The Company has identified several prospects on the block that are being evaluated for future drilling. In light of the government's claim, the timing of drilling a well is uncertain.

Nigeria. A partially-owned subsidiary of the Company joined Oranto Petroleum and Orandi Petroleum in an existing production sharing contract on Block 320 in deepwater Nigeria gaining exploration rights from the Nigerian National Petroleum Corporation. The subsidiary, which holds a 51 percent interest in Block 320, is owned 59 percent by the Company and 41 percent by an unaffiliated third party. The Company completed a 3-D seismic survey covering the block in 2006. The Company currently expects to drill the first exploration well on the block in the second half of 2007.

The Company owns a 25 percent working interest in Devon Energy-operated Block 256 offshore Nigeria. During the first quarter of 2006, the Company participated in the drilling of the Pina 1-X well on Block 256 in the deepwater of Nigeria, which was unsuccessful. The partners plan to drill an additional well on Block 256 in the second quarter of 2007 to test a different type of play.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information from continuing operations for the Company as of and for each of the years ended December 31, 2006, 2005 and 2004. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

Production, price and cost data. The following tables set forth production, price and cost data with respect to the Company's properties for 2006, 2005 and 2004. These amounts represent the Company's historical results from continuing operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. The production amounts will not agree to the reserve volume tables in the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" due to field fuel volumes and production from discontinued operations being included in the reserve volume tables.

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2006				
	United States	Canada	South Africa	Tunisia	Total
Production information:					
Annual sales volumes:					
Oil (MBbls)	6,467	113	1,506	871	8,957
NGLs (MBbls)	6,748	169	—	—	6,917
Gas (MMcf)	103,928	15,848	—	436	120,212
Total (MBOE)	30,536	2,924	1,506	944	35,910
Average daily sales volumes:					
Oil (Bbls)	17,716	311	4,127	2,386	24,540
NGLs (Bbls)	18,488	463	—	—	18,951
Gas (Mcf)	284,732	43,420	—	1,195	329,347
Total (BOE)	83,659	8,011	4,127	2,585	98,382
Average prices, including hedge results and amortization of deferred VPP revenue:					
Oil (per Bbl)	$ 65.73	$ 65.57	$ 65.92	$ 63.16	$ 65.51
NGLs (per Bbl)	$ 35.24	$ 51.47	$ —	$ —	$ 35.64
Gas (per Mcf)	$ 6.15	$ 6.75	$ —	$ 5.97	$ 6.23
Revenue (per BOE)	$ 42.64	$ 42.11	$ 65.92	$ 61.05	$ 44.06
Average prices, excluding hedge results and amortization of deferred VPP revenue:					
Oil (per Bbl)	$ 62.92	$ 65.57	$ 65.74	$ 63.16	$ 63.45
NGLs (per Bbl)	$ 35.24	$ 51.47	$ —	$ —	$ 35.64
Gas (per Mcf)	$ 5.96	$ 6.61	$ —	$ 5.97	$ 6.04
Revenue (per BOE)	$ 41.37	$ 41.35	$ 65.74	$ 61.05	$ 42.91
Average costs (per BOE):					
Production costs:					
Lease operating	$ 5.64	$ 9.50	$ 14.47	$ 1.99	$ 6.23
Third-party transportation charges	.82	6.03	—	1.42	1.22
Taxes:					
Ad valorem	1.45	—	—	—	1.24
Production	1.99	—	—	—	1.69
Workover	.72	1.29	—	—	.71
Total	$ 10.62	$ 16.82	$ 14.47	$ 3.41	$ 11.09
Depletion expense	$ 9.07	$ 15.39	$ 6.28	$ 4.25	$ 9.34

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2005				
	United States	Canada	South Africa	Tunisia	Total
Production information:					
Annual sales volumes:					
Oil (MBbls)	8,008	77	2,405	1,269	11,759
NGLs (MBbls)	6,352	184	—	—	6,536
Gas (MMcf)	98,927	13,296	—	—	112,223
Total (MBOE)	30,849	2,476	2,405	1,269	36,999
Average daily sales volumes:					
Oil (Bbls)	21,942	210	6,588	3,477	32,217
NGLs (Bbls)	17,403	503	—	—	17,906
Gas (Mcf)	271,033	36,427	—	—	307,460
Total (BOE)	84,517	6,784	6,588	3,477	101,366
Average prices, including hedge results and amortization of deferred VPP revenue:					
Oil (per Bbl)	$ 32.01	$ 52.12	$ 53.01	$ 52.98	$ 38.70
NGLs (per Bbl)	$ 31.72	$ 45.79	$ —	$ —	$ 32.12
Gas (per Mcf)	$ 6.94	$ 7.67	$ —	$ —	$ 7.02
Revenue (per BOE)	$ 37.09	$ 46.18	$ 53.01	$ 52.98	$ 39.28
Average prices, excluding hedge results and amortization of deferred VPP revenue:					
Oil (per Bbl)	$ 54.05	$ 52.12	$ 53.01	$ 52.98	$ 53.71
NGLs (per Bbl)	$ 31.72	$ 45.79	$ —	$ —	$ 32.12
Gas (per Mcf)	$ 7.26	$ 7.67	$ —	$ —	$ 7.31
Revenue (per BOE)	$ 43.86	$ 46.21	$ 53.01	$ 52.98	$ 44.93
Average costs (per BOE):					
Production costs:					
Lease operating	$ 4.55	$ 6.65	$ 11.79	$ 1.66	$ 5.06
Third-party transportation charges	.66	6.29	—	1.54	1.03
Taxes:					
Ad valorem	1.31	—	—	—	1.09
Production	1.94	—	—	—	1.61
Workover	.53	1.89	—	—	.57
Total	$ 8.99	$ 14.83	$ 11.79	$ 3.20	$ 9.36
Depletion expense	$ 7.10	$ 12.71	$ 10.19	$ 3.75	$ 7.56

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2004				
	United States	Canada	South Africa	Tunisia	Total
Production information:					
Annual sales volumes:					
Oil (MBbls)	8,001	26	3,429	845	12,301
NGLs (MBbls)	7,203	155	—	—	7,358
Gas (MMcf)	76,629	9,372	—	—	86,001
Total (MBOE)	27,976	1,743	3,429	845	33,993
Average daily sales volumes:					
Oil (Bbls)	21,863	72	9,368	2,308	33,611
NGLs (Bbls)	19,678	425	—	—	20,103
Gas (Mcf)	209,371	25,606	—	—	234,977
Total (BOE)	76,437	4,764	9,368	2,308	92,877
Average prices, including hedge results and amortization of deferred VPP revenue:					
Oil (per Bbl)	$ 29.53	$ 48.37	$ 37.87	$ 39.14	$ 32.56
NGLs (per Bbl)	$ 25.05	$ 32.03	$ —	$ —	$ 25.20
Gas (per Mcf)	$ 4.99	$ 4.72	$ —	$ —	$ 4.96
Revenue (per BOE)	$ 28.57	$ 28.93	$ 37.87	$ 39.14	$ 29.79
Average prices, excluding hedge results and amortization of deferred VPP revenue:					
Oil (per Bbl)	$ 39.22	$ 48.37	$ 38.60	$ 39.14	$ 39.06
NGLs (per Bbl)	$ 25.05	$ 32.03	$ —	$ —	$ 25.20
Gas (per Mcf)	$ 5.46	$ 5.37	$ —	$ —	$ 5.45
Revenue (per BOE)	$ 32.62	$ 32.45	$ 38.60	$ 39.14	$ 33.37
Average costs (per BOE):					
Production costs:					
Lease operating	$ 3.32	$ 4.90	$ 8.31	$ 2.04	$ 3.87
Third-party transportation charges	.18	5.02	—	1.54	.44
Taxes:					
Ad valorem	.99	—	—	—	.82
Production	1.33	—	—	—	1.10
Workover	.42	.87	—	—	.39
Total	$ 6.24	$ 10.79	$ 8.31	$ 3.58	$ 6.62
Depletion expense	$ 5.34	$ 12.93	$ 12.86	$ 4.43	$ 6.46

Productive wells. The following table sets forth the number of productive oil and gas wells attributable to the Company's properties as of December 31, 2006, 2005 and 2004:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2006:						
United States	4,605	4,180	8,785	3,821	3,906	7,727
Argentina	—	—	—	—	—	—
Canada	48	832	880	31	699	730
South Africa	4	2	6	2	1	3
Tunisia	10	—	10	2	—	2
Total	4,667	5,014	9,681	3,856	4,606	8,462
As of December 31, 2005:						
United States	4,300	3,955	8,255	3,531	3,669	7,200
Argentina	821	261	1,082	684	202	886
Canada	65	675	740	30	511	541
South Africa	8	—	8	2	—	2
Tunisia	4	—	4	2	—	2
Total	5,198	4,891	10,089	4,249	4,382	8,631
As of December 31, 2004:						
United States	3,999	3,990	7,989	3,288	3,563	6,851
Argentina	744	226	970	607	168	775
Canada	38	489	527	25	358	383
South Africa	5	—	5	2	—	2
Tunisia	4	—	4	1	—	1
Total	4,790	4,705	9,495	3,923	4,089	8,012

(a) Productive wells consist of producing wells and wells capable of production, including shut-in wells. One or more completions in the same well bore are counted as one well. If any well in which one of the multiple completions is an oil completion, then the well is classified as an oil well. As of December 31, 2006, the Company owned interests in 208 gross wells containing multiple completions.

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2006:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
United States:					
Onshore	1,374,610	1,203,463	2,897,525	1,306,252	291,987
Offshore	59,340	21,007	235,126	185,197	10,500
	1,433,950	1,224,470	3,132,651	1,491,449	302,487
Canada	266,000	194,000	547,000	488,000	23,000
South Africa	124,600	55,590	3,503,400	1,576,530	—
Tunisia	212,420	42,484	3,812,253	2,581,278	—
West Africa	—	—	1,297,951	495,476	—
Total	2,036,970	1,516,544	12,293,255	6,632,733	325,487

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2006:

	Acres Expiring (a)	
	Gross	Net
2007 (b)	7,580,318	4,380,838
2008	585,640	349,826
2009	1,045,412	528,766
2010	380,582	317,256
2011	281,594	177,313
Thereafter	2,419,709	878,734
Total	12,293,255	6,632,733

(a) Acres expiring are based on contractual lease maturities.

(b) Acres subject to expiration during 2007 include 3.5 million gross acres (1.6 million net acres) in South Africa, 3.8 million gross acres (2.6 million net acres) in Tunisia and 264,665 gross acres (223,030 net acres) in North America. The acreage in South Africa relates to areas where the Company has no intention to drill, has no cost basis in the acreage and intends to let the acreage expire. In Tunisia, the Company either has received extensions, plans to make the necessary expenditures to extend the acreage or intends to seek extensions on the 2007 expirations. As to the remaining acreage the Company may extend the leases prior to their expiration based upon 2007 planned activities or for other business reasons. In certain leases, the extension is only subject to the Company's election to extend and the fulfillment of certain capital expenditures commitments. In other cases, the extensions are subject to the consent of third parties, and no assurance can be given that the requested extensions will be granted. See "Description of Properties" above for information regarding the Company's drilling operations.

Drilling activities. The following table sets forth the number of gross and net productive and dry hole wells in which the Company had an interest that were drilled during 2006, 2005 and 2004. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to the Company of productive wells compared to the costs of dry holes.

DRILLING ACTIVITIES

	Gross Wells			Net Wells		
	Year Ended December 31,			Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
United States:						
Productive wells:						
Development	662	537	268	619	505	243
Exploratory	52	40	8	42	37	5
Dry holes:						
Development	8	7	3	7	7	3
Exploratory	8	7	6	6	5	3
	730	591	285	674	554	254
Argentina:						
Productive wells:						
Development	14	65	43	14	64	42
Exploratory	4	19	21	4	18	21
Dry holes:						
Development	1	4	1	1	4	1
Exploratory	2	14	10	2	14	10
	21	102	75	21	100	74
Canada:						
Productive wells:						
Development	2	27	3	2	26	3
Exploratory	326	87	27	297	72	25
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	16	7	24	15	7	23
	344	121	54	314	105	51
South Africa:						
Productive wells:						
Development	2	—	—	1	—	—
Exploratory	—	1	—	—	—	—
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	1	—	—	1	—	—
Total	3	1	—	2	—	—
Tunisia:						
Productive wells:						
Development	—	—	2	—	—	1
Exploratory	2	2	1	1	1	—
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	2	2	—	—	1	—
Total	4	4	3	1	2	1
West Africa:						
Productive wells:						
Development	—	—	—	—	—	—
Exploratory	—	—	1	—	—	1
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	1	1	5	—	—	4
	1	1	6	—	—	5
Total	1,103	820	423	1,012	761	385
Success ratio (a)	96%	95%	88%	97%	95%	89%

(a) Represents the ratio of those wells that were successfully completed as producing wells or wells capable of producing to total wells drilled and evaluated.

The following table sets forth information about the Company's wells upon which drilling was in progress as of December 31, 2006:

	Gross Wells	Net Wells
United States:		
Development	18	17
Exploratory	21	14
	39	31
Canada:		
Development	3	2
Exploratory	16	12
	19	14
South Africa:		
Development	2	1
Exploratory	—	—
	2	1
Tunisia:		
Development	—	—
Exploratory	5	3
	5	3
Total	65	49

ITEM 3. LEGAL PROCEEDINGS

The Company is party to the legal proceedings that are described under "Legal actions" in Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The Company is also party to other proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The Company did not submit any matters to a vote of security holders during the fourth quarter of 2006.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

The Company's common stock is listed and traded on the NYSE under the symbol "PXD". The Board declared dividends to the holders of the Company's common stock of $.25 per share and $.22 per share during each of the years ended December 31, 2006 and 2005, respectively.

The following table sets forth quarterly high and low prices of the Company's common stock and dividends declared per share for the years ended December 31, 2006 and 2005:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2006:			
Fourth quarter	$ 44.46	$ 36.48	$ —
Third quarter	$ 46.68	$ 37.07	$ .13
Second quarter	$ 46.75	$ 36.43	$ —
First quarter	$ 54.46	$ 37.98	$ .12
Year ended December 31, 2005:			
Fourth quarter	$ 55.98	$ 45.39	$ —
Third quarter	$ 56.35	$ 39.66	$ .12
Second quarter	$ 45.24	$ 36.67	$ —
First quarter	$ 44.82	$ 32.91	$ .10

On February 13, 2007, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $40.34 per share.

As of February 13, 2007, the Company's common stock was held by approximately 26,534 holders of record.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's purchases of treasury stock during the three months ended December 31, 2006:

Period	Total Number of Shares (or Units) Purchased (a)	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs
October 2006	1,347,746	$ 37.92	1,343,100	
November 2006	4,700	$ 40.02	4,700	
December 2006	46	$ 43.00	-	
Total	1,352,492	$ 37.93	1,347,800	$ 13,988,043

(a) Amounts include shares withheld to fund tax withholding on employees' stock awards for which restrictions have lapsed.

During August 2005, the Board approved a share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock, $345.3 million and $640.7 million of which were completed in 2006 and 2005, respectively. In February 2007, the Board approved a new share repurchase program authorizing the purchase of up to $300 million of the Company's common stock.

ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data as of and for each of the five years ended December 31, 2006 for the Company should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data".

	Year Ended December 31, (a)				
	2006	2005	2004	2003	2002
	(in millions, except per share data)				
Statements of Operations Data:					
Revenues and other income:					
Oil and gas	$ 1,582.0	$ 1,453.2	$ 1,012.6	$ 725.8	$ 551.9
Interest and other (b)	58.7	31.6	2.2	7.8	7.6
Gain (loss) on disposition of assets, net	(7.9)	59.8	—	1.4	4.2
	1,632.8	1,544.6	1,014.8	735.0	563.7
Costs and expenses:					
Oil and gas production	398.3	346.4	224.9	162.4	152.2
Depletion, depreciation and amortization	359.5	299.9	231.6	170.3	154.7
Impairment of long-lived assets (c)	—	.6	39.7	—	—
Exploration and abandonments	264.1	163.3	113.3	93.9	47.9
General and administrative	121.8	114.3	73.2	54.4	43.4
Accretion of discount on asset retirement obligations	4.8	4.2	4.1	2.9	—
Interest	107.0	126.1	102.0	91.3	95.8
Hurricane activity, net (d)	32.0	39.8	—	—	—
Other (e)	36.3	99.5	28.4	16.6	30.2
	1,323.8	1,194.1	817.2	591.8	524.2
Income from continuing operations before income taxes and cumulative effect of changes in accounting principle	309.0	350.5	197.6	143.2	39.5
Income tax benefit (provision) (f)	(136.7)	(155.8)	(63.1)	134.2	(.9)
Income from continuing operations before cumulative effect of change in accounting principle	172.3	194.7	134.5	277.4	38.6
Income from discontinued operations, net of tax (a)	567.4	339.9	178.4	117.8	(11.9)
Income (loss) before cumulative effect of change in accounting principle	739.7	534.6	312.9	395.2	26.7
Cumulative effect of change in accounting principle, net of tax (g)	—	—	—	15.4	—
Net income	$ 739.7	$ 534.6	$ 312.9	$ 410.6	$ 26.7
Income from continuing operations before cumulative effect of change in accounting principle per share:					
Basic	$ 1.39	$ 1.42	$ 1.07	$ 2.37	$ .34
Diluted	$ 1.36	$ 1.40	$ 1.06	$ 2.34	$ .34
Net income per share:					
Basic	$ 5.95	$ 3.90	$ 2.50	$ 3.50	$ .24
Diluted	$ 5.81	$ 3.80	$ 2.46	$ 3.46	$ .23
Weighted average shares outstanding:					
Basic	124.4	137.1	125.2	117.2	112.5
Diluted	127.6	141.4	127.5	118.5	114.3
Dividends declared per share	$ .25	$ .22	$ .20	$ —	$ —
Balance Sheet Data (as of December 31):					
Total assets	$ 7,355.4	$ 7,329.2	$ 6,733.5	$ 3,951.6	$ 3,455.1
Long-term obligations and minority interests	$ 3,483.7	$ 4,078.8	$ 3,357.2	$ 1,762.0	$ 1,805.6
Total stockholders' equity	$ 2,984.7	$ 2,217.1	$ 2,831.8	$ 1,759.8	$ 1,374.9

(a) Certain amounts for periods prior to January 1, 2006 have been reclassified (i) in accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144") to reflect the results of operations of certain assets disposed of during 2006 as discontinued operations, rather than as a component of continuing operations (see Notes B and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional discussion) and (ii) to conform with the current year presentation.

(b) Interest and other income in 2006 and 2005 include $7.6 million and $14.2 million, respectively, of income associated with various business interruption insurance claims. See Notes M and U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(c) During 2005 and 2004, the Company recorded $.6 million and $39.7 million of impairment charges for its Gabonese Olowi field because development of the discovery was canceled due to significant increases in projected field development costs. See Note S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(d) Hurricane activity, net, for 2006 and 2005 includes $75.0 million and $39.8 million, respectively, of charges to reclaim and abandon the East Cameron facilities destroyed by Hurricane Rita. In 2006, the Company recorded $43.0 million of estimated insurance recoveries associated with debris removal. See Note U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(e) Other expense for 2006, 2005, 2003 and 2002 includes losses on the early extinguishment of debt of $8.1 million, $26.0 million, $1.5 million and $22.3 million, respectively. Other expense for 2006, 2005, 2004, 2003 and 2002 includes $(11.6) million, $44.2 million, $4.2 million, $2.8 million and $1.7 million, respectively, of derivative ineffectiveness charges (credits). See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(f) Income tax benefit for 2003 includes a $197.7 million adjustment to reduce United States deferred tax asset valuation allowances.

(g) Cumulative effect of change in accounting principle for 2003 relates to the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Strategic Initiatives and Goals

During 2006, the Company accomplished significant goals underlying the strategic initiatives established in 2005 to enhance shareholder value and investment returns. Together with other important accomplishments, the Company:

- Substantially completed a $1 billion share repurchase program, $640.7 million of which was completed during 2005 and $345.3 million of which was completed during 2006
- Completed the divestiture of the Company's assets in Argentina for net proceeds of $669.6 million, resulting in a gain of $10.9 million
- Completed the divestiture of the Company's assets in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $726.2 million
- Reduced higher-risk, higher-impact exploration spending to approximately five percent of the total capital spent in 2006
- Focused capital spending on lower-risk North American onshore development and extension drilling
- Produced 35.9 MMBOE in 2006 from continuing operations
- Increased the semi-annual dividend to shareholders to $0.13 per share

Financial and Operating Performance

Pioneer's financial and operating performance for 2006 included the following highlights:

- Average daily sales volumes, on a BOE basis, decreased three percent in 2006 as compared to 2005, primarily due to a 126 percent increase in the delivery of VPP volumes. Excluding the delivery of the VPP volumes in 2006 (5.6 MMBOE) and 2005 (2.5 MMBOE), the Company's North American production increased approximately nine percent, which the Company believes provides a better understanding of the actual results of the Company's 2006 North American drilling program excluding the increased VPP deliveries.
- Oil and gas revenues increased nine percent in 2006 as compared to 2005, primarily as a result of increases in worldwide oil and NGL prices.
- Net income increased 38 percent to $739.7 million ($5.81 per diluted share) in 2006 from $534.6 million ($3.80 per diluted share) in 2005, primarily on the strength of higher oil and NGL prices and gains on the sale of deepwater Gulf of Mexico and Argentine assets.
- Income from continuing operations decreased to $172.3 million ($1.36 per diluted share) for 2006, as compared to $194.7 million ($1.40 per diluted share) for 2005, primarily due to higher exploration and abandonment expenses in 2006.
- The Company recognized income from discontinued operations of $567.4 million ($4.45 per diluted share) during 2006, primarily attributable to the sale of deepwater Gulf of Mexico and Argentine assets, as compared to income from discontinued operations of $339.9 million ($2.40 per diluted share) during 2005.

- Outstanding debt decreased to $1.5 billion at December 31, 2006 as compared to $2.1 billion at December 31, 2005, primarily due to the application of sales proceeds from the Company's divestment of its assets in Argentina and the deepwater Gulf of Mexico.

- The Company's debt-to-capitalization was 33 percent at December 31, 2006 as compared to 48 percent at December 31, 2005.

- Net cash provided by operating activities decreased by $522.3 million, or 41 percent as compared to that of 2005, primarily due to the sale of deepwater Gulf of Mexico and Argentine assets during 2006 and Canadian and Gulf of Mexico shelf assets during 2005.

- The Company added 91 MMBOE of proved reserves during 2006, resulting in total proved reserves of 904.9 MMBOE at December 31, 2006.

2007 Outlook and Activities

Commodity prices. Significant factors that may impact 2007 commodity prices include developments in the issues currently impacting Iraq and Iran and the Middle East in general; the extent to which members of the OPEC and other oil exporting nations are able to continue to manage oil supply through export quotas; and overall North American gas supply and demand fundamentals, including the impact of increasing LNG deliveries to the United States. Although the Company cannot predict the occurrence of events that may affect 2007 commodity prices or the degree to which these prices will be affected, the prices for any commodity that the Company produces will generally approximate current market prices in the geographic region of the production. Pioneer will continue to strategically hedge a portion of its oil and gas price risk to mitigate the impact of price volatility on its oil, NGL and gas revenues. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's commodity hedge positions at December 31, 2006. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for disclosures about the Company's commodity related derivative financial instruments.

Capital budget for 2007. The Company announced a 2007 capital budget of $1.1 billion, excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs. The 2007 capital budget is allocated (i) 50 percent to low-risk development drilling in onshore North American core areas, (ii) 25 percent to the development of the South African South Coast Gas and Alaskan Oooguruk projects, (iii) 20 percent to test and develop lower-risk resource plays in onshore North America and Tunisia and (iv) 5 percent to high-impact exploration activities in the United States and West Africa. The Company plans to drill and recomplete approximately 650 to 700 wells during 2007.

2007 Annual Production. The Company believes that the results from its 2006 drilling program and 2007 capital budget will allow the Company to realize production growth during 2007 of 10 percent or more as compared to the Company's 2006 production.

First Quarter 2007 Outlook. Based on current estimates, the Company expects that first quarter 2007 production will average 97,000 to 102,000 BOEPD. The range reflects the typical variability in the timing of oil cargo shipments in South Africa and Tunisia and the recent downtime related to severe winter weather in the Company's Rockies and Mid-Continent areas, which is expected to reduce first quarter production by approximately 3,000 BOEPD.

First quarter production costs (including production and ad valorem taxes and transportation costs) are expected to average $11.25 to $12.25 per BOE based on current NYMEX strip prices for oil and gas, reduced production due to weather downtime and increased weather-related repair costs. Depletion, depreciation and amortization ("DD&A") expense is expected to average $10.00 to $11.00 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $50 million to $90 million including (i) up to $25 million from high-impact drilling on Alaska's North Slope, (ii) up to $30 million from activities in the Company's resource plays in the Edwards Trend in South Texas, Uinta/Piceance in the Rockies area, Canada and Tunisia, (iii) $30 million in seismic investments and personnel costs, primarily related to the resource plays the Company is currently progressing and (iv) $5 million related to acreage and other costs. General and administrative expense is expected to be $30 million to $35 million. Interest expense is expected to be $25 million to $28 million. Accretion of discount on asset retirement obligations is expected to be $1 million to $2 million.

The Company's first quarter effective income tax rate is expected to range from 37 percent to 45 percent based on current capital spending plans and higher tax rates in certain foreign jurisdictions. Cash income taxes are expected to range from $5 million to $15 million, principally related to Tunisian income taxes.

Share repurchase programs. In February 2007, the Company announced that the Board approved a new share repurchase program that authorizes the purchase of up to $300 million of the Company’s common stock. This share repurchase program follows the Company’s previous share repurchase programs of $1 billion and $300 million, which were essentially completed during 2006 and 2005, respectively.

Acquisitions

2006 acquisition expenditures. During 2006, the Company spent approximately $223.2 million to acquire proved and unproved properties, which was comprised of approximately $144.8 million of proved properties and $78.3 million of unproved properties. The proved properties were primarily bolt-on and acreage acquisitions in the Spraberry field and Edwards Trend area. In North America, the acquisition of unproved properties is comprised of acreage acquisitions in the Spraberry field, Edwards Trend area, Rockies area, Alaska and Canada. The Company also acquired an additional interest in its Jenein Nord block in Tunisia and recognized additional obligations associated with its Nigerian prospects during 2006.

2005 acquisition expenditures. In July 2005, the Company completed the acquisition of approximately 70 MMBOE of substantially proved undeveloped oil reserves in the United States core areas of the Permian Basin and South Texas for $170.7 million.

2004 Evergreen merger. On September 28, 2004, Pioneer completed a merger with Evergreen Resources, Inc. ("Evergreen"). Pioneer acquired the common stock of Evergreen for a total purchase price of approximately $1.8 billion, which was comprised of cash and Pioneer common stock.

Divestitures

Argentina and Deepwater Gulf of Mexico. During March 2006, the Company sold its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $726.2 million. During April 2006, the Company sold its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. The historic results of these properties and the related gains on disposition are reported as discontinued operations.

Volumetric production payments. During January 2005, the Company sold 20.5 MMBOE of proved reserves in the Hugoton and Spraberry fields, by means of two VPPs for net proceeds of $592.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements.

During April 2005, the Company sold 7.3 MMBOE of proved reserves in the Spraberry field, by means of a VPP for net proceeds of $300.3 million, including the value attributable to certain derivative hedge agreements assigned to the buyer of the April VPP.

The Company's VPPs represent limited-term overriding royalty interests in oil and gas reserves which: (i) entitle the purchaser to receive production volumes over a period of time from specific lease interests; (ii) are free and clear of all associated future production costs and capital expenditures; (iii) are nonrecourse to the Company (i.e., the purchaser’s only recourse is to the assets acquired); (iv) transfers title of the assets to the purchaser and (v) allows the Company to retain the assets after the VPPs volumetric quantities have been delivered.

Canada and Shelf Gulf of Mexico. During 2005, the Company sold its interests in the Martin Creek and Conroy Black areas of northeast British Columbia and the Lookout Butte area of southern Alberta for net proceeds of $197.2 million, resulting in a gain of $138.3 million. During 2005, the Company also sold all of its interests in certain oil and gas properties on the Gulf of Mexico shelf for net proceeds of $59.2 million, resulting in a gain of $27.9 million. The historic results of these properties and the related gains on disposition are reported as discontinued operations.

Gabon divestiture. In 2005, the Company closed the sale of the shares in a Gabonese subsidiary that owns the interest in the Olowi block for $47.9 million of net proceeds, resulting in a gain of $47.5 million with no associated income tax effect either in Gabon or the United States. In addition, Pioneer retains the potential, under certain circumstances, to receive additional payments for production discovered from deeper reservoirs on the block, if any.

Results of Operations

Oil and gas revenues. Oil and gas revenues totaled $1.6 billion, $1.5 billion and $1.0 billion during 2006, 2005 and 2004, respectively. The revenue increase during 2006, as compared to 2005, was due to a 69 percent increase in reported oil prices, including the effects of commodity price hedges and VPP deliveries, and an 11 percent increase in NGL prices. Partially offsetting the effects of increased oil and NGL prices was an 11 percent decrease in reported gas prices, including the effects of commodity price hedges and VPP deliveries, and a three percent decrease in average daily sales volumes on a BOE basis. The revenue increase during 2005, as compared to 2004, was due to a 19 percent increase in reported oil prices, a 27 percent increase in NGL prices and a 42 percent increase in reported gas prices, including the effects of commodity price hedges and VPP deliveries, along with increased production in 2005 on a BOE basis.

A significant factor contributing to the increases in reported oil prices and decreases in reported oil sales volumes in 2006 as compared to 2005 was the initiation of first deliveries of oil volumes under the Company’s VPP agreements in January 2006. Similarly, reported gas prices and decreases in gas sales volumes in 2006 and 2005 as compared to 2004 were impacted by the initiation of first deliveries of gas volumes under the Company’s VPP agreements during the first half of 2005 offset by the decline in underlying gas prices. In accordance with GAAP, VPP deliveries result in VPP deferred revenue amortization being recognized in oil and gas revenues with no associated sales volumes being recorded.

The following table provides average daily sales volumes from continuing operations, including the effects of delivery of the VPP volumes, by geographic area and in total, for 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Oil (Bbls):			
United States	17,716	21,942	21,863
Canada	311	210	72
South Africa	4,127	6,588	9,368
Tunisia	2,386	3,477	2,308
Worldwide	24,540	32,217	33,611
NGLs (Bbls):			
United States	18,488	17,403	19,678
Canada	463	503	425
Worldwide	18,951	17,906	20,103
Gas (Mcf):			
United States	284,732	271,033	209,371
Canada	43,420	36,427	25,606
South Africa	—	—	—
Tunisia	1,195	—	—
Worldwide	329,347	307,460	234,977
Total (BOE):			
United States	83,659	84,517	76,437
Canada	8,011	6,784	4,764
South Africa	4,127	6,588	9,368
Tunisia	2,585	3,477	2,308
Worldwide	98,382	101,366	92,877

On a BOE basis, average daily production for 2006, as compared to 2005, increased by 18 percent in Canada, while average daily production decreased by one percent in the United States and by 33 percent in Africa. Average daily per BOE production for 2005, as compared to 2004, increased by 11 percent and 42 percent in the United States and Canada, respectively, and decreased by 14 percent in Africa.

Average daily production in the United States was slightly lower during 2006, as compared to 2005, primarily due to a 126 percent increase in VPP oil and gas deliveries on a BOE basis, partially offset by accelerated development drilling in core areas. The increase in United States production volumes during 2005, as compared to 2004, was primarily due to production from properties acquired in the Evergreen merger, partially offset by first deliveries of VPP gas volumes during 2005.

Canadian average daily sales volumes increased during 2006, as compared to 2005, primarily due to the significant drilling activity in the CBM Horseshoe Canyon area. The increase in Canadian production volumes during 2005, as compared to 2004, was primarily due to new production from Canadian properties acquired in the Evergreen merger and production from new wells drilled during the 2004 – 2005 winter drilling program.

Production declined in Africa during 2006 and 2005 primarily due to (i) normal production declines from producing properties in South Africa and Tunisia, partially offset by drilling success in Tunisia and (ii) the Company's interest in the Adam Concession in Tunisia being reduced in 2006 from 24 percent to 20 percent in accordance with the terms of the concession agreement. In Tunisia, the Company recorded gas sales volumes and revenue for the first time after finalizing a gas sales arrangement during 2006.

The following table provides average daily sales volumes from discontinued operations during 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Oil (Bbls):			
United States	2,400	5,280	4,774
Argentina	2,515	7,869	8,534
Canada	—	28	65
Worldwide	4,915	13,177	13,373
NGLs (Bbls):			
United States	—	65	60
Argentina	421	1,824	1,546
Canada	—	112	492
Worldwide	421	2,001	2,098
Gas (Mcf):			
United States	36,038	230,171	312,468
Argentina	43,905	137,032	121,654
Canada	14	6,489	16,261
Worldwide	79,957	373,692	450,383
Total (BOE):			
United States	8,406	43,707	56,912
Argentina	10,253	32,531	30,356
Canada	2	1,221	3,267
Worldwide	18,661	77,459	90,535

The following table provides average reported prices from continuing operations, including the results of hedging activities and the amortization of VPP deferred revenue, and average realized prices from continuing operations, excluding the results of hedging activities and the amortization of VPP deferred revenue, by geographic area and in total, for 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Average reported prices:			
Oil (per Bbl):			
United States	$ 65.73	$ 32.01	$ 29.53
Canada	$ 65.57	$ 52.12	$ 48.37
South Africa	$ 65.92	$ 53.01	$ 37.87
Tunisia	$ 63.16	$ 52.98	$ 39.14
Worldwide	$ 65.51	$ 38.70	$ 32.56
NGL (per Bbl):			
United States	$ 35.24	$ 31.72	$ 25.05
Canada	$ 51.47	$ 45.79	$ 32.03
Worldwide	$ 35.64	$ 32.12	$ 25.20
Gas (per Mcf):			
United States	$ 6.15	$ 6.94	$ 4.99
Canada	$ 6.75	$ 7.67	$ 4.72
Tunisia	$ 5.97	$ —	$ —
Worldwide	$ 6.23	$ 7.02	$ 4.96
Average realized prices:			
Oil (per Bbl):			
United States	$ 62.92	$ 54.05	$ 39.22
Canada	$ 65.57	$ 52.12	$ 48.37
South Africa	$ 65.74	$ 53.01	$ 38.60
Tunisia	$ 63.16	$ 52.98	$ 39.14
Worldwide	$ 63.45	$ 53.71	$ 39.06
NGL (per Bbl):			
United States	$ 35.24	$ 31.72	$ 25.05
Canada	$ 51.47	$ 45.79	$ 32.03
Worldwide	$ 35.64	$ 32.12	$ 25.20
Gas (per Mcf):			
United States	$ 5.96	$ 7.26	$ 5.46
Canada	$ 6.61	$ 7.67	$ 5.37
Tunisia	$ 5.97	$ —	$ —
Worldwide	$ 6.04	$ 7.31	$ 5.45

Hedging activities. The Company, from time to time, utilizes commodity swap and collar contracts in order to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. During 2006, 2005 and 2004, the Company's commodity price hedges decreased oil and gas revenues from continuing operations by $149.0 million, $284.9 million and $121.9 million, respectively. The effective portions of changes in the fair values of the Company's commodity price hedges are deferred as increases or decreases to stockholders' equity until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedges add volatility to the Company's reported stockholders' equity until the hedge derivative matures or is terminated. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the impact to oil and gas revenues during 2006, 2005 and 2004 from the Company's hedging activities, the Company's open and terminated hedge positions at December 31, 2006 and descriptions of the Company's commodity hedge derivatives. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosures about the Company's commodity related derivative financial instruments.

Subsequent to December 31, 2006, the Company reduced its oil hedge positions by terminating certain oil swap contracts and increased its gas hedge position by adding additional gas swap contracts. See Note J of Notes to

Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning these changes in the oil and gas hedge positions.

Deferred revenue. During 2006 and 2005, the Company's recognition of previously deferred VPP revenue increased oil and gas revenues from continuing operations by $190.3 million and $75.8 million, respectively. The Company’s amortization of deferred VPP revenue is scheduled to increase 2007 oil and gas revenues by $181.2 million. See Note T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's VPPs.

Interest and other income. The Company’s interest and other income totaled $58.7 million, $31.5 million and $2.2 million during 2006, 2005 and 2004, respectively. The $27.2 million increase during 2006, as compared to 2005, is primarily attributable to (i) $13.8 million of hedge ineffectiveness gains recorded during 2006, (ii) a $13.2 million increase in interest income primarily attributable to the investing the proceeds from the Argentine and deepwater Gulf of Mexico divestitures during 2006 and (iii) $5.6 million of Alaskan exploration incentive credits received in 2006, offset by a $6.6 million decrease in business interruption insurance claims primarily attributable to the 2005 Fain plant fire in the West Panhandle field. The increase in interest and other income during 2005, as compared to 2004, is primarily attributable to the recognition of $14.2 million in business interruption insurance claims related to the Fain plant fire. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding interest and other income.

Gain (loss) on disposition of assets. The Company recorded a net loss on disposition of assets of $7.9 million in 2006, as compared to net gains of $59.8 million and $39,000 during 2005 and 2004, respectively.

In 2005, the gain was primarily related to (i) the sale of the stock of a subsidiary that owned the interest in the Olowi block in Gabon, which resulted in a $47.5 million gain and (ii) a $14 million insurance settlement on the Company's East Cameron facility that was destroyed by Hurricane Rita, which resulted in a $9.7 million gain.

During 2006, the Company recognized gains on the sale of its interest in certain oil and gas properties in the deepwater Gulf of Mexico and its Argentina assets of approximately $737.1 million. During 2005, the Company also recognized gains on the sale of certain assets in Canada and the shelf of the Gulf of Mexico of approximately $166.2 million. However, pursuant to SFAS 144, these gains and the results of operations from the assets are presented as discontinued operations.

The net cash proceeds from asset divestitures during 2006, 2005 and 2004 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties and stock repurchase programs, and to reduce outstanding indebtedness. See Notes N and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Oil and gas production costs. The Company’s oil and gas production costs totaled $398.3 million, $346.4 million and $224.9 million during 2006, 2005 and 2004, respectively. In general, lease operating expenses and workover expenses represent the components of oil and gas production costs over which the Company has management control, while production taxes and ad valorem taxes are directly related to commodity price changes. Total production costs per BOE increased during 2006 by 18 percent as compared to 2005 primarily due to (i) the impact of a 126 percent increase in delivered volumes under VPP agreements, for which the Company bears all associated production costs and records no associated sales volumes (representing a per BOE production cost impact of approximately $1.50 during 2006 as compared to $.59 during 2005), (ii) general inflation of field service and supply costs and (iii) increases in production and ad valorem taxes and field utility costs due to increasing commodity and utility prices.

Total production costs per BOE increased during 2005 by 41 percent as compared to 2004. The increase in total production costs per BOE during 2005 as compared to 2004 was primarily attributable to (i) an increase in production and ad valorem taxes as a result of higher commodity prices, (ii) higher Canadian gas transportation fees, (iii) the retention of production costs related to VPP volumes sold (approximately $.59 per BOE, during 2005), (iv) new production added from the Evergreen merger, which are relatively higher per BOE operating cost properties and (v) increases in field service and supply costs primarily associated with rising commodity prices.

The following tables provide the components of the Company's total production costs per BOE and total production costs per BOE by geographic area for 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Lease operating expenses	$ 6.23	$ 5.06	$ 3.87
Third-party transportation charges	1.22	1.03	.44
Taxes:			
Ad valorem	1.24	1.09	.82
Production	1.69	1.61	1.10
Workover costs	.71	.57	.39
Total production costs	$11.09	$ 9.36	$ 6.62

	Year Ended December 31,		
	2006	2005	2004
United States	$10.62	$ 8.99	$ 6.24
Canada	$16.82	$ 14.83	$ 10.79
South Africa	$14.47	$ 11.79	$ 8.31
Tunisia	$ 3.41	$ 3.20	$ 3.58
Worldwide	$11.09	$ 9.36	$ 6.62

Depletion, depreciation and amortization expense. The Company's total DD&A expense was $10.01, $8.11 and $6.81 per BOE for 2006, 2005 and 2004, respectively. Depletion expense, the largest component of DD&A expense, was $9.34, $7.56 and $6.46 per BOE during 2006, 2005 and 2004, respectively. During 2006, the increase in per BOE depletion expense was primarily due to (i) a generally increasing trend in the Company’s oil and gas properties’ cost bases per BOE of proved and proved developed reserves as a result of cost inflation in drilling rig rates and drilling supplies, (ii) the aforementioned sale of proved reserves under VPP agreements, for which the Company removed proved reserves with no corresponding decrease in cost basis, (iii) a $.50 per BOE increase in Tunisian depletion, primarily associated with 2006 and 2005 decreases in the Company’s interest in the Adam Concession, offset by (iv) a $3.91 per BOE decrease in South Africa depletion, primarily associated with 2006 and 2005 positive revisions to proved reserves based on well performance.

During 2005, the increase in per BOE depletion expense was due to relatively higher per BOE cost basis Rocky Mountains area production acquired in the Evergreen merger and a higher depletion rate for the Hugoton and Spraberry fields as a result of the VPP volumes sold.

The following table provides depletion expense per BOE from continuing operations by geographic area for 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
United States	$ 9.07	$ 7.10	$ 5.34
Canada	$ 15.39	$ 12.71	$ 12.93
South Africa	$ 6.28	$ 10.19	$ 12.86
Tunisia	$ 4.25	$ 3.75	$ 4.43
Worldwide	$ 9.34	$ 7.56	$ 6.46

Impairment of oil and gas properties. The Company reviews its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. During 2005 and 2004, the Company recognized noncash impairment charges of $644 thousand and $39.7 million, respectively, to reduce the carrying value of its Gabonese Olowi field assets as development of the discovery was canceled. See "Critical Accounting Estimates" below and Notes B and S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information pertaining to the Company's accounting policies regarding assessments of impairment and the Gabonese Olowi field impairment, respectively.

Exploration, abandonments, geological and geophysical costs. The following table provides the Company's geological and geophysical costs, exploratory dry hole expense, lease abandonments and other exploration expense by geographic area for 2006, 2005 and 2004:

	United States	Canada	South Africa	Tunisia	Other	Total
Year ended December 31, 2006:						
Geological and geophysical	$ 79,141	$ 5,287	$ 289	$ 8,402	$ 21,536	$ 114,655
Exploratory dry holes	80,023	6,438	7,227	6,214	15,845	115,747
Leasehold abandonments and other	13,696	2,223	—	—	17,824	33,743
	$ 172,860	$ 13,948	$ 7,516	$ 14,616	$ 55,205	$ 264,145
Year ended December 31, 2005:						
Geological and geophysical	$ 63,707	$ 4,452	$ 282	$ 1,857	$ 32,213	$ 102,511
Exploratory dry holes	24,462	3,468	804	9,041	9,135	46,910
Leasehold abandonments and other	8,957	1,625	125	—	3,195	13,902
	$ 97,126	$ 9,545	$ 1,211	$ 10,898	$ 44,543	$ 163,323
Year ended December 31, 2004:						
Geological and geophysical	$ 49,722	$ 4,047	$ 868	$ 2,042	$ 11,923	$ 68,602
Exploratory dry holes	1,150	11,132	(338)	—	24,798	36,742
Leasehold abandonments and other	4,138	3,883	—	—	6	8,027
	$ 55,010	$ 19,062	$ 530	$ 2,042	$ 36,727	$ 113,371

During 2006, significant components of the Company's dry hole provisions and leasehold abandonments expense included (i) $34.0 million of costs associated with the Company’s unsuccessful exploratory well on its Block 256 prospect offshore Nigeria, including $17.8 million of associated unproved leasehold impairment, (ii) $21.6 million of dry hole provisions recorded for the Company’s unsuccessful Cronus, Storms and Antigua prospects in the North Slope area of Alaska, (iii) $16.9 million of dry hole provisions and abandonment costs recognized on prospects drilled in prior periods that were being evaluated for commerciality, including $7.2 million of costs associated with the Company’s Boomslang prospect offshore South Africa, $5.5 million of costs associated with two discoveries on the Gulf of Mexico shelf in 2005 and $4.2 million of costs associated with the Company’s Anaguid permit in Tunisia, (iv) $16.0 million of dry hole provision and unproved property impairment recognized on the Company’s unsuccessful Norphlet prospect in Mississippi, (v) a $14.3 million unsuccessful well on the Company’s Flying Cloud prospect in the Gulf of Mexico and (vi) $6.4 million of unsuccessful exploratory wells in Canada. During 2006, the Company completed and evaluated 414 exploration/extension wells, 384 of which were successfully completed as discoveries.

Significant components of the Company's dry hole expense during 2005 included (i) $21.2 million related to Alaskan well costs, (ii) $9.5 million associated with an unsuccessful Nigerian well, (iii) $3.5 million attributable to an unsuccessful suspended well in the Company’s El Hamra permit in Tunisia, (iv) $5.1 million attributable to an unsuccessful suspended well in the Company’s Anaguid permit in Tunisia and (v) various other exploratory wells. During 2005, the Company completed and evaluated 180 exploratory/extension wells, 149 of which were successfully completed as discoveries.

Significant components of the Company's dry hole expense during 2004 included (i) $19.0 million on the Company’s Gabonese Olowi prospect and (ii) $5.8 million associated with the Company’s Bravo prospect offshore Equatorial Guinea. During 2004, the Company completed and evaluated 103 exploratory/extension wells, 58 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense totaled $121.8 million, $114.2 million and $73.2 million during 2006, 2005 and 2004, respectively. The increase in general and administrative expense during 2006, as compared to 2005, was primarily due to a full year effect of the 2005 staff increases associated with the Evergreen acquisition. The Company continues to review its general and administrative expenses and remains focused on initiatives to control its expenditures.

The increase in general and administrative expense during 2005, as compared to 2004, was primarily due to increases in administrative staff, including staff increases associated with the Evergreen merger, and performance-related compensation costs, including the amortization of restricted stock awarded to officers, directors and employees during 2005.

Interest expense. Interest expense was $107.0 million, $126.1 million and $102.0 million during 2006, 2005 and 2004, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2006 was 6.7 percent, as compared to 6.5 percent and 5.4 percent for the years ended December 31, 2005 and 2004, respectively, including the effects of interest rate derivatives. The decrease in interest expense for 2006 as compared to 2005 was primarily due to the repayment of portions of the Company's outstanding borrowings under the Company's credit facility with proceeds from the divestiture of the deepwater Gulf of Mexico and Argentine assets and an $11.1 million increase in interest capitalized on the Company's Oooguruk development project in Alaska and the South Coast Gas project in South Africa, partially offset by a $4.1 million decrease in the amortization of interest rate hedge gains.

The increase in interest expense for 2005 as compared to 2004 was primarily due to increased average borrowings under the Company's lines of credit, primarily as a result of the cash portion of the consideration paid in the Evergreen merger and $949.3 million of stock repurchases completed during 2005, a $15.2 million decrease in the amortization of interest rate hedge gains, the assumption of $300 million of notes in connection with the Evergreen merger and higher interest rates in 2005.

See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's long-term debt and interest expense.

Hurricane activity, net. The Company recorded net hurricane related activity expenses of $32.0 million and $39.8 million during 2006 and 2005, respectively, associated with the Company's East Cameron platform facility, located on the Gulf of Mexico shelf, that was destroyed during 2005 by Hurricane Rita.

The Company does not plan to rebuild the facility based on the economics of the field. During the fourth quarter of 2006, the Company's application to "reef in-place" a substantial portion of the East Cameron debris was denied. As a result, the Company currently estimates that it will cost approximately $119 million to reclaim and abandon the East Cameron facility. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis and fee proposal prepared by a third-party engineering firm for the majority of the work and an estimate by the Company for the remainder. During 2006 and 2005, the Company recorded additional abandonment obligation charges of $75 million and $39.8 million, respectively. The operations to reclaim and abandon the East Cameron facilities began in January 2007 and the Company expects to incur a substantial portion of the costs in 2007. The Company expects that a substantial portion of the total estimated cost to reclaim and abandon the facility will be covered by insurance, including 100 percent of the debris removal costs. Consequently, the Company has recorded a $43.0 million insurance recovery receivable corresponding to the estimated debris removal costs.

Other expenses. Other expenses were $36.3 million during 2006, as compared to $99.4 million during 2005 and $28.4 million during 2004. The $63.1 million decrease in other expenses during 2006, as compared to 2005, is primarily attributable to (i) a $53.2 million decrease in hedge ineffectiveness charges and other derivative losses and (ii) a $17.9 million decrease in loss on early extinguishment of portions of the Company's senior notes.

The increase in other expenses during 2005, as compared to 2004, is primarily attributable to (i) a $43.9 million increase in hedge ineffectiveness and other derivative losses and (ii) a $26.0 million loss on the redemption and tender of portions of the Company's senior notes. See Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a detailed description of the components included in other expenses.

Income tax provision. The Company recognized income tax provisions on continuing operations of $136.7 million, $155.8 million and $63.1 million during 2006, 2005 and 2004, respectively. The Company’s effective tax rates for 2006, 2005 and 2004 were 44.2 percent, 44.5 percent and 31.9 percent, respectively, as compared to the combined United States federal and state statutory rates of approximately 36.5 percent. The effective tax rates of 2006 and 2005 differ from the combined United States federal and state statutory rates primarily due to:

- foreign tax rates,
- adjustments to the deferred tax liability for changes in enacted tax laws and rates, as discussed below,
- statutes in foreign jurisdictions that differ from those in the United States,
- recognition of $8.4 million of deferred tax benefit during 2006 as a result of the conversion of senior convertible notes prior to the Company's repayment of the debt principal,
- recognition of $7.2 million of taxes during 2005 associated with the repatriation of foreign earnings pursuant to the American Jobs Creation Act of 2004 and
- expenses for unsuccessful well costs and associated acreage costs in foreign locations where the Company does not expect to receive income tax benefits.

During May 2006, the State of Texas enacted legislation that changed the existing Texas franchise tax from a tax based on net income or taxable capital to an income tax based on a defined calculation of gross margin (the "Texas margin tax"). Also, during 2006, the Canadian federal and provincial governments enacted tax rate reductions that will be phased in over several years. SFAS No. 109, "Accounting for Income Taxes" requires that deferred tax balances be adjusted to reflect tax rate changes during the periods in which the tax rate changes are enacted. The adjustment due to the enactment of the Texas margin tax and the Canadian tax rate changes resulted in a $13.5 million United States tax expense and a $10.2 million Canadian tax benefit during the year ended December 31, 2006, respectively.

See "Critical Accounting Estimates" below and Note P of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's tax position.

Discontinued operations. During 2005 and 2006, the Company sold its interests in the following oil and gas asset groups:

Country	Description of Asset Groups	Date Divested
Canada	Martin Creek, Conroy Black and Lookout Butte fields	May 2005
United States	Two Gulf of Mexico shelf fields	August 2005
United States	Deepwater Gulf of Mexico fields	March 2006
Argentina	Argentine assets	April 2006

The Company recognized income from discontinued operations of $567.4 million during 2006, as compared to $339.9 million during 2005 and $178.4 million during 2004. Pursuant to SFAS 144, the results of operations of these properties and the related gains on disposition are reported as discontinued operations. See Note V of Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" for additional data on discontinued operations.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for exploration, development and acquisition of oil and gas properties, repayment of contractual obligations and working capital obligations. Funding for exploration, development and acquisition of oil and gas properties and repayment of contractual obligations may be provided by any combination of internally-generated cash flow, proceeds from the disposition of nonstrategic assets or alternative financing sources as discussed in "Capital resources" and "Financing activities" below. Generally, funding for the Company's working capital obligations is provided by internally-generated cash flows.

Payments for acquisitions, net of cash acquired. In 2004, the Company paid $880.4 million of cash, net of $12.1 million of cash acquired, and issued shares of the Company's common stock to complete the Evergreen merger. The Company also assumed $300 million principal amount of Evergreen notes and other current and noncurrent obligations associated with the Evergreen merger. As is further discussed in "Financing activities" below, and in Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data", the Company financed the cash costs utilizing credit facilities.

Oil and gas properties. The Company's cash expenditures for additions to oil and gas properties during 2006, 2005 and 2004 totaled $1.4 billion, $1.1 billion and $562.9 million, respectively. The Company's 2006 expenditures for additions to oil and gas properties were funded by $754.8 million of net cash provided by operating activities and by a portion of the net proceeds from the disposition of deepwater Gulf of Mexico and Argentine assets. The Company's 2005 and 2004 expenditures for additions to oil and gas properties were internally funded by $1.3 billion and $1.1 billion, respectively, of net cash provided by operating activities.

The Company strives to maintain its indebtedness at levels which will provide sufficient financial flexibility to take advantage of future opportunities. The Company's capital budget for 2007 is approximately $1.1 billion. The Company believes that Credit Agreement borrowings and net cash provided by operating activities during 2007, based on the current price environment, will be sufficient to fund the 2007 capital expenditures budget.

Off-balance sheet arrangements. From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2006, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, (iv) VPP obligations (to physically deliver volumes and pay related lease operating expenses in the future) and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable such as derivative contracts that are sensitive to future changes in commodity prices and gas transportation commitments. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "Contractual obligations" below for more information regarding the Company's off-balance sheet arrangements.

Contractual obligations. The Company's contractual obligations include long-term debt, operating leases, drilling commitments (including commitments to pay day rates for drilling rigs), derivative obligations, other liabilities, transportation commitments and VPP obligations.

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2006:

	Payments Due by Year			
	2007	**2008 and 2009**	**2010 and 2011**	**Thereafter**
	(in thousands)			
Long-term debt (a)	$ 32,075	$ 3,777	$ 328,000	$ 1,232,985
Operating leases (b)	29,065	27,906	7,429	—
Drilling commitments (c)	330,381	307,265	—	—
Derivative obligations (d)	78,233	121,126	—	—
Other liabilities (e)	170,156	70,932	25,750	108,660
Transportation commitments (f)	68,630	137,396	130,992	170,546
VPP obligations (g)	181,232	306,044	135,166	42,069
	$ 889,772	$ 974,446	$ 627,337	$ 1,554,260

(a) See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data". The amounts included in the table above represent principal maturities only.

(b) See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

(c) Drilling commitments represent future minimum expenditure commitments for drilling rig services and well commitments under contracts to which the Company was a party on December 31, 2006.

(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2006. These liabilities include $131.1 million of liabilities that are fixed in amount and are not subject to continuing market risk. The ultimate settlement amounts of the remaining portions of the Company's derivative obligations are unknown because they are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative obligations.

(e) The Company's other liabilities represent current and noncurrent other liabilities that are comprised of benefit obligations, litigation and environmental contingencies, asset retirement obligations and other obligations for which neither the ultimate settlement amounts nor their timings can be precisely determined in advance. See Notes H, I and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's post retirement benefit obligations, litigation contingencies and asset retirement obligations, respectively.

(f) Transportation commitments represent estimated transportation fees on gas throughput commitments. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's transportation commitments.

(g) These amounts represent the amortization of the deferred revenue associated with the VPPs. The Company's ongoing obligation is to deliver the specified volumes sold under the VPPs free and clear of all associated production costs and capital expenditures. See Note T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

Environmental contingency. A subsidiary of the Company has been notified by a letter from the Texas Commission on Environmental Quality ("TCEQ") dated August 24, 2005 that the TCEQ considers the subsidiary to be a potentially responsible party with respect to the Dorchester Refining Company State Superfund Site located in Mount Pleasant, Texas. In connection with the acquisition of oil and gas assets in 1991, the Company acquired a group of companies, one of which was an entity that had owned a refinery located at the Mount Pleasant site from 1977 until 1984. According to the TCEQ, this refinery was responsible for releases of hazardous substances into the environment. Pursuant to applicable Texas law, the Company's subsidiary, which does not own any material assets or conduct any material operations, may be subject to strict, joint and several liability for the costs of conducting a study to evaluate potential remedial options and for the costs of performing any remediation ultimately required by the TCEQ. The Company does not know the nature and extent of the alleged contamination, the potential costs of remediation or the portion, if any, of such costs that may be allocable to the Company's subsidiary; however, the Company has noted that there appear to be other operators or owners who may share responsibility for these costs and does not expect that any such additional liability will have a material adverse effect on its consolidated financial position as a whole or on its liquidity, financial position or future annual results of operations. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding this matter as well as other environmental and legal contingencies involving the Company.

Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from financing activities and proceeds from sales of nonstrategic assets. The Company expects that these resources will be sufficient to fund its capital commitments during 2007 and for the foreseeable future.

Asset divestitures. During March 2006, the Company sold all of its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $726.2 million. During April 2006, the Company sold its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. The results of operations for these divestitures are included in the Company's discontinued operations. The net cash proceeds from these divestitures were used to reduce outstanding indebtedness under the Credit Agreement, to fund a portion of additions to oil and gas properties, for stock repurchases and for general corporate purposes.

During May 2005, the Company sold all of its interests in the Martin Creek, Conroy Black and Lookout Butte oil and gas properties in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million. During August 2005, the Company sold all of its interests in certain oil and gas properties on the Gulf of Mexico shelf for net proceeds of $59.2 million, resulting in a gain of $27.9 million. During October 2005, the Company sold all of its shares in a subsidiary that owns the interest in the Olowi block in Gabon for net proceeds of $47.9 million, resulting in a gain of $47.5 million. The net cash proceeds from the 2005 divestitures were used to reduce outstanding indebtedness.

During January 2005, the Company sold 20.5 MMBOE of proved reserves, by means of two VPPs for net proceeds of $592.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were used to reduce outstanding indebtedness.

During April 2005, the Company sold 7.3 MMBOE of proved reserves, by means of another VPP for net proceeds of $300.3 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPP were used to reduce outstanding indebtedness.

See Note T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's VPPs.

Operating activities. Net cash provided by operating activities during 2006, 2005 and 2004 was $754.8 million, $1.3 billion and $1.1 billion, respectively. The decrease in net cash provided by operating activities in 2006, as compared to that of 2005, was primarily due to the loss of cash flow from the aforementioned asset divestitures. The increase in net cash provided by operating activities in 2005, as compared to that of 2004, was primarily due to higher commodity prices and the operations acquired in the Evergreen merger.

Investing activities. Net cash provided by investing activities during 2006 was $145.5 million, as compared to net cash provided by investing activities of $84.7 million during 2005 and net cash used in investing activities of $1.5 billion during 2004. The increase in net cash provided by investing activities during 2006, as compared to 2005, was primarily due to a $396.2 million increase in proceeds from disposition of assets, partially offset by a $280.6 million increase in additions to oil and gas properties. The decrease in net cash used in investing activities during 2005, as compared to 2004, was primarily due to (i) $1.2 billion in proceeds from asset divestitures in 2005, which included $892.6 million of net proceeds received from VPPs sold during 2005 and (ii) $880.4 million of cash consideration paid in 2004 in connection with the Evergreen merger offset by an increase of $560.4 million in additions to oil and gas properties. See "Results of Operations" above and Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Financing activities. Net cash used in financing activities was $913.5 million and $1.4 billion during 2006 and 2005, respectively. Net cash provided by financing activities during 2004 was $414.3 million. During 2006, significant components of financing activities included $554.7 million of net cash used to repay long-term borrowings, $348.9 million of net cash used to purchase 8.9 million shares of stock and $31.7 million of dividend payments, partially offset by $17.4 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. During 2005, financing activities were comprised of $353.6 million of net principal repayments on long-term debt, $60.1 million of payments of other noncurrent liabilities, primarily comprised of cash settlements of acquired hedge obligations, $30.3 million of dividends paid and $949.3 million of stock repurchases, partially offset by $41.6 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases. During 2004, financing activities were comprised of $553.4 million of net principal borrowings on long-term debt, $54.3 million of payments of other noncurrent liabilities, primarily comprised of settlements of fair value and acquired hedge obligations and other financial obligations, $92.3 million of stock repurchases and $26.6 million of dividends paid, partially offset by $35.1 million of proceeds from the exercise of long-term incentive plan stock options and employee stock purchases.

During September 2005, the Company announced that the Board had approved a share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock. During 2006 and 2005, the Company expended a total of $348.9 million to acquire 8.9 million shares of stock and $949.3 million to acquire 20.0 million shares of stock, respectively, of which $345.3 million and $940.3 million, respectively, were repurchased pursuant to the repurchase programs. In February 2007, the Board approved a new share repurchase program authorizing the purchase of up to $300 million of the Company's common stock.

During May 2006, the Company issued $450 million of 6.875% Notes for net proceeds of $447.4 million. The Company used the net proceeds, in part, from the 6.875% Notes to repurchase $346.2 million of its 6.50% Notes and for general corporate purposes.

During 2006, holders of all of the $100 million of 4 3/4% Senior Convertible Notes due 2021 exercised their conversion rights. Associated therewith, the Company paid $79.9 million in cash, issued 2.3 million shares of common stock and recorded a $22.0 million increase to stockholders' equity.

During September 2005, the Company entered into an amended credit facility that provides for initial aggregate loan commitments of $1.5 billion and a five-year term (the "Credit Agreement"). Effective September 2006, the participating lenders extended the maturity on $1.395 billion of aggregate loan commitments under the Credit Agreement to September 30, 2011.

During April 2005, $131.0 million of the Company's 8 7/8% senior notes due 2005 matured and were repaid. During 2005, the Company also redeemed the remaining $64.0 million and $16.2 million, respectively, of aggregate principal amount of its 9 5/8% senior notes due 2010 and its 7.50% senior notes due 2012. During September 2005, the Company accepted tenders to purchase $188.4 million in principal amount of the 5.875% senior notes due 2012 for $199.9 million. The Company utilized unused borrowing capacity under its credit facility to fund these financing activities.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Board.

Liquidity. The Company's principal source of short-term liquidity is the Credit Agreement. There was $328.0 million of outstanding borrowings under the Credit Agreement as of December 31, 2006. Including $150.2 million of undrawn and outstanding letters of credit under the Credit Agreement, the Company had $1.0 billion of unused borrowing capacity as of December 31, 2006.

Debt ratings. The Company receives debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investor Services, Inc. ("Moody's"), which are subject to regular reviews. During 2005, S&P lowered the Company's corporate credit rating to BB+ with a stable outlook from BBB-. During 2006, Moody's cut the Company's corporate credit rating to Ba1 with a negative outlook from Baa3. S&P and Moody's consider many factors in determining the Company's ratings, including: production growth opportunities, liquidity, debt levels and asset and reserve mix. As a result of the downgrades, the interest rate and fees the Company pays on the Credit Agreement have increased and additional debt covenant requirements under the Credit Agreement were triggered. During 2006, as a result of the Company's downgrades by the rating agencies, the Company issued additional letters of credits of approximately $79.1 million pursuant to agreements that contain provisions with rating triggers. The individual downgrades are not expected to materially affect the Company's financial position or liquidity, but could negatively impact the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. The Company's book capitalization at December 31, 2006 was $4.5 billion, consisting of debt of $1.5 billion and stockholders' equity of $3.0 billion. Consequently, the Company's debt to book capitalization decreased to 33 percent at December 31, 2006 from 48 percent at December 31, 2005. The Company's ratio of current assets to current liabilities was .60 to 1.00 at December 31, 2006, essentially unchanged from December 31, 2005.

Critical Accounting Estimates

The Company prepares its consolidated financial statements for inclusion in this Report in accordance with GAAP. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a comprehensive discussion of the Company's significant accounting policies. GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. Following is a discussion of the Company's most critical accounting estimates, judgments and uncertainties that are inherent in the Company's application of GAAP.

Asset retirement obligations. The Company has significant obligations to remove tangible equipment and facilities and to restore land or seabed at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells and removing and disposing of offshore oil and gas platforms. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligations, a corresponding adjustment is made to the oil and gas property balance. See Notes B and L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that, during periods of active exploration, net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense. During 2006, 2005 and 2004, the Company recognized exploration, abandonment, geological and geophysical expense from (i) continuing operations of $264.1 million, $163.3 million and $113.4 million, respectively, and (ii) discontinued operations of $7.3 million, $63.9 million and $68.3 million, respectively, under the successful efforts method.

Proved reserve estimates. Estimates of the Company's proved reserves included in this Report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data,
- the interpretation of that data,
- the accuracy of various mandated economic assumptions and
- the judgment of the persons preparing the estimate.

The Company's proved reserve information included in this Report as of December 31, 2006, 2005 and 2004 was prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties. Estimates prepared by third parties may be higher or lower than those included herein.

Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify, positively or negatively, material revisions to the estimate of proved reserves.

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2006 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the Standardized Measure 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. See "Item 1A. Risk Factors" for additional information regarding estimates of proved reserves.

The Company's estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which the Company records depletion expense will increase, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of the Company's assessment of its proved properties and goodwill for impairment.

Impairment of proved oil and gas properties. The Company reviews its proved properties to be held and used whenever management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon its outlook of future commodity prices and net cash flows that may be generated by the properties and if a significant downward revision has occurred to the estimated proved reserves. Proved oil and gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated.

Impairment of unproved oil and gas properties. Management periodically assesses unproved oil and gas properties for impairment, on a project-by-project basis. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects impacts the amount and timing of impairment provisions, if any.

Suspended wells. The Company suspends the costs of exploratory wells that discover hydrocarbons pending a final determination of the commercial potential of the oil and gas discovery. The ultimate disposition of these well costs is dependent on the results of future drilling activity and development decisions. If the Company decides not to pursue additional appraisal activities or development of these fields, the costs of these wells will be charged to exploration and abandonment expense.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its Consolidated Balance Sheets for more than one year following the completion of drilling unless the exploratory well finds oil and gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well.

(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain Alaskan, deepwater Gulf of Mexico and foreign projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is impaired. See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's suspended exploratory well costs.

Assessments of functional currencies. Management determines the functional currencies of the Company's subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. The U.S. dollar is the functional currency of all of the Company's international operations except Canada. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Argentine economic and currency measures. In April 2006, the Company sold its assets in Argentina for proceeds of $669.6 million, resulting in a gain of $10.9 million. Prior to the divestiture, the accounting for and remeasurement of the Company's Argentine balance sheets as of December 31, 2005 reflect management's assumptions regarding some uncertainties unique to Argentina's economic environment. The Argentine economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items, the timing of repatriations of the sales proceeds and contingent liabilities associated with the Company's retained obligations and its indemnifications provided to the purchaser of the assets. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note B of Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for a description of the assumptions utilized in the preparation of these financial statements.

Deferred tax asset valuation allowances. The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that its deferred tax assets will be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and reassesses the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurances that facts and circumstances will not materially change and require the Company to establish deferred tax asset valuation allowances in certain jurisdictions in a future period. As of December 31, 2006, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to certain foreign tax jurisdictions.

Goodwill impairment. The Company reviews its goodwill for impairment at least annually. This requires the Company to estimate the fair value of the assets and liabilities of the reporting units that have goodwill. There is considerable judgment involved in estimating fair values, particularly in the estimation of proved reserves as described above. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information.

Litigation and environmental contingencies. The Company makes judgments and estimates in recording liabilities for ongoing litigation and environmental remediation. Actual costs can vary from such estimates for a variety of reasons. The costs to settle litigation can vary from estimates based on differing interpretations of laws and opinions and assessments on the amount of damages. Similarly, environmental remediation liabilities are subject to change because of changes in laws and regulations, developing information relating to the extent and nature of site contamination and improvements in technology. Under GAAP, a liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimable. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's commitments and contingencies.

Valuations of defined benefit pension and postretirement plans. The Company is the sponsor of certain defined benefit pension and postretirement plans. In accordance with GAAP, the Company is required to estimate the present value of its unfunded pension and accumulated postretirement benefit obligations. Based on those values, the Company records the unfunded obligations of those plans and records ongoing service costs and associated interest expense. The valuation of the Company’s pension and accumulated postretirement benefit obligations requires management assumptions and judgments as to benefit cost inflation factors, mortality rates and discount factors. Changes in these factors may materially change future benefit costs and pension and accumulated postretirement benefit obligations. See "New Accounting Pronouncements" below and Note H of Notes to Consolidated Financial Statements included in “Item 8. Consolidated Financial Statements and Supplementary

Data" for additional information regarding the Company's pension and accumulated postretirement benefit obligations.

Valuation of stock-based compensation. The Company adopted the "modified prospective" approach as prescribed under SFAS No. 123(R) on January 1, 2006. Under this approach, the Company is required to expense all options and other stock-based compensation that vested during the year of adoption based on the fair value of the award on the grant date. The calculation of the fair value of stock-based compensation requires the use of estimates to derive the various inputs necessary for using the Black-Scholes valuation method elected by the Company.

New Accounting Pronouncements

The following discussions provide information about new accounting pronouncements that were issued by the Financial Accounting Standards Board ("FASB") during 2006:

FIN 48. In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN No. 48"). The Interpretation clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN No. 48 also provides guidance on measurement, classification, interim accounting and disclosure. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company is continuing to assess the potential impacts of this Interpretation.

SFAS 157. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measures" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measures required under other accounting pronouncements, but does not change existing guidance as to whether or not an instrument is carried at fair value. SFAS 157 is effective for fiscal years beginning after November 15, 2007. The Company is continuing to assess the impact of SFAS 157**.**

SFAS 158. In September 2006, the FASB issued SFAS 158, "Employers' Accounting for Defined Benefit Pension and other Postretirement Plans" ("SFAS 158"). Under SFAS 158, a business entity that sponsors one or more single-employer defined benefit plans is required to:

- recognize the funded status of a benefit plan in its balance sheet, measured as the difference between plan assets at fair value (with limited exceptions) and the benefit obligation,
- recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost,
- measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position and
- disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition assets or obligations.

An employer with publicly traded securities is required to initially recognize the funded status of its defined benefit postretirement plans and to provide the required disclosures as of the end of the first fiscal year ending after December 15, 2006. The Company has adopted the provisions of SFAS 158 effective on December 31, 2006. The Company previously recognized the funded status of its defined benefit postretirement plans and currently recognizes periodic changes in its defined benefit postretirement plans as components of service costs in the period of change as allowed by SFAS 158. Consequently, the adoption of SFAS 158 did not have a material impact on the Company's liquidity, financial position or future results of operations. See Note H of Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's postretirement plans.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2006 and 2005, and from which the Company may incur future gains or losses from changes in market interest rates, foreign exchange rates or commodity prices. Although certain derivative contracts to which the Company has been a party did not qualify as hedges, the Company does not enter into derivative or other financial instruments for trading purposes.

The fair value of the Company's derivative contracts is determined based on counterparties' estimates and valuation models. The Company did not change its valuation method during 2006. During 2006, the Company was a party to commodity, interest rate and foreign exchange rate swap contracts and commodity collar contracts. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts, including deferred gains and losses on terminated derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2006:

	Derivative Contract Net Liabilities (a)			
	Commodity	Interest Rate	Foreign Exchange Rate	Total
	(in thousands)			
Fair value of contracts outstanding as of December 31, 2005	$ (748,477)	$ —	$ —	$ (748,477)
Changes in contract fair values (b)	187,895	1,349	(22)	189,222
Contract maturities	163,955	—	22	163,977
Contract terminations	328,399	(1,349)	—	327,050
Fair value of contracts outstanding as of December 31, 2006	$ (68,228)	$ —	$ —	$ (68,228)

____

(a) Represents the fair values of open derivative contracts subject to market risk. The Company also had $131.1 million and $870 thousand of obligations under terminated derivatives as of December 31, 2006 and 2005, respectively, for which no market risk exists.

(b) At inception, new derivative contracts entered into by the Company have no intrinsic value.

Quantitative Disclosures

Foreign exchange rate sensitivity. From time-to-time, the Company's Canadian subsidiary enters into short-term forward currency agreements to purchase Canadian dollars with U.S. dollar gas sales proceeds. The Company does not designate these derivatives as hedges due to their short-term nature. There were no outstanding forward currency agreements at December 31, 2006.

Interest rate sensitivity. The following tables provide information about other financial instruments to which the Company was a party as of December 31, 2006 and 2005 that were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2006 and 2005. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for LIBOR on February 19, 2007. As of December 31, 2006, the Company was not a party to material derivatives that would subject it to interest rate sensitivity.

Interest Rate Sensitivity
Debt Obligations as of December 31, 2006

	Year Ending December 31,							Liability Fair Value at December 31,
	2007	2008	2009	2010	2011	Thereafter	Total	2006
	(in thousands, except interest rates)							
Total Debt:								
Fixed rate principal maturities (a)	$ 32,075	$ 3,777	$ —	$ —	$ —	$ 1,232,985	$ 1,268,837	$ 1,244,846
Weighted average interest rate (%)	6.64	6.25	6.51	6.51	6.51	6.51		
Variable rate maturities	$ —	$ —	$ —	$ 22,960	$ 305,040	$ —	$ 328,000	$ 328,000
Average interest rate (%)	6.23	5.87	5.88	5.96	6.28	—		

(a) Represents maturities of principal amounts excluding (i) debt issuance discounts and premiums and (ii) deferred fair value hedge gains and losses.

Interest Rate Sensitivity
Debt Obligations as of December 31, 2005

	Year Ending December 31,							Liability Fair Value at December 31,
	2006	2007	2008	2009	2010	Thereafter	Total	2005
	(in thousands, except interest rates)							
Total Debt:								
Fixed rate principal maturities (a)	$ —	$ 32,075	$ 350,000	$ —	$ —	$ 882,985	$ 1,265,060	$ 1,369,404
Weighted average interest rate (%)	6.31	6.29	6.16	6.16	6.16	6.16		
Variable rate maturities	$ —	$ —	$ —	$ —	$ 900,000	$ —	$ 900,000	$ 900,000
Average interest rate (%)	5.88	6.00	6.02	6.10	6.16	—		

(a) Represents maturities of principal amounts excluding (i) debt issuance discounts and premiums and (ii) deferred fair value hedge gains and losses.

Commodity price sensitivity. The following tables provide information about the Company's oil and gas derivative financial instruments that were sensitive to changes in oil and gas prices as of December 31, 2006 and 2005. As of December 31, 2006 and 2005, all of the Company's oil and gas derivative financial instruments qualified as hedges.

Commodity hedge instruments. The Company hedges commodity price risk with derivative contracts, such as swap and collar contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor") and maximum ("ceiling") prices for the Company on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price.

See Notes B, E and J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the accounting procedures followed by the Company relative to hedge derivative financial instruments and for specific information regarding the terms of the Company's derivative financial instruments that are sensitive to changes in oil or gas prices.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2006

	Year Ending December 31, 2007	2008	2009	Liability Fair Value at December 31, 2006 (in thousands)
Oil Hedge Derivatives:				
Average daily notional Bbl volumes (a):				
Swap contracts (b)	4,512	6,500	—	$ 130,574
Weighted average fixed price per Bbl	$ 31.44	$ 31.19	$ —	
Average forward NYMEX oil prices (c)	$ 61.47	$ 63.93	$ 63.86	

(a) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices by calendar quarter.

(b) Subsequent to December 31, 2006, the Company reduced its oil hedge positions by terminating the following oil swap contracts which are included in the table above: (i) 4,342 Bbls per day of 2007 swap contracts with a fixed price of $31.47 per Bbl and (ii) 2,500 Bbls per day of 2008 swap contracts with a fixed price of $29.90 per Bbl.

(c) The average forward NYMEX oil prices are based on February 19, 2007 market quotes.

Oil Price Sensitivity
Derivative Financial Instruments as of December 31, 2005

	Year Ending December 31, 2006	2007	2008	Liability Fair Value at December 31, 2005 (in thousands)
Oil Hedge Derivatives:				
Average daily notional Bbl volumes:				
Swap contracts	10,000	13,000	17,000	$ 441,189
Weighted average fixed price per Bbl	$ 31.69	$ 30.89	$ 29.21	
Collar contracts	9,129	4,500	—	$ 21,879
Weighted average ceiling price per Bbl	$ 74.92	$ 90.43	$ —	
Weighted average floor price per Bbl	$ 44.25	$ 50.00	$ —	
Average forward NYMEX oil prices (a)	$ 62.72	$ 65.52	$ 64.84	

(a) The average forward NYMEX oil prices are based on February 15, 2006 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2006

	Year Ending December 31,		Asset Fair Value at December 31,
	2007	2008	2006
			(in thousands)
Gas Hedge Derivatives (a) (b):			
Average daily notional MMBtu volumes (c):			
Swap contracts	86,194	15,000	$ 54,835
Weighted average fixed price per MMBtu	$ 8.13	$ 8.62	
Collar contracts	6,164	—	$ 7,511
Weighted average ceiling price per MMBtu	$ 11.52	$ —	
Weighted average floor price per MMBtu	$ 9.00	$ —	
Average forward NYMEX gas prices (d)	$ 7.99	$ 8.29	

(a) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and collar contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(b) Subsequent to December 31, 2006, the Company entered into additional gas swap contracts of approximately 102,192 MMBtu per day at an average price of $8.13 per MMBtu for the Company's 2007 production.

(c) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for hedge volumes and weighted average prices by calendar quarter.

(d) The average forward NYMEX gas prices are based on February 19, 2007 market quotes.

Gas Price Sensitivity
Derivative Financial Instruments as of December 31, 2005

	Year Ending December 31,			Liability Fair Value at December 31,
	2006	2007	2008	2005
				(in thousands)
Gas Hedge Derivatives (a):				
Average daily notional MMBtu volumes:				
Swap contracts	73,842	29,195	5,000	$ 213,543
Weighted average fixed price per MMBtu	$ 4.30	$ 4.28	$ 5.38	
Collar contracts	183,685	215,000	—	$ 71,866
Weighted average ceiling price per MMBtu	$ 13.76	$ 11.84	$ —	
Weighted average floor price per MMBtu	$ 6.62	$ 6.57	$ —	
Average forward NYMEX gas prices (b)	$ 7.81	$ 8.99	$ 8.76	

(a) To minimize basis risk, the Company enters into basis swaps for a portion of its gas hedges to convert the index price of the hedging instrument from a NYMEX index to an index which reflects the geographic area of production. The Company considers these basis swaps as part of the associated swap and collar contracts and, accordingly, the effects of the basis swaps have been presented together with the associated contracts.

(b) The average forward NYMEX gas prices are based on February 15, 2006 market quotes.

Qualitative Disclosures

Non-derivative financial instruments. The Company is a borrower under fixed rate and variable rate debt instruments that give rise to interest rate risk. The Company's objective in borrowing under fixed or variable rate debt is to satisfy capital requirements while minimizing the Company's costs of capital. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's debt instruments.

Derivative financial instruments. The Company utilizes interest rate, foreign exchange rate and commodity price derivative contracts to hedge interest rate, foreign exchange rate and commodity price risks in accordance with policies and guidelines approved by the Board. In accordance with those policies and guidelines, the Company's executive management determines the appropriate timing and extent of hedge transactions.

Foreign currency, operations and price risk. International investments represent, and are expected to continue to represent, a significant portion of the Company's total assets. Pioneer currently has international operations in Africa and Canada, which together represented 18 percent of the Company's 2006 oil and gas revenues. Although Pioneer's primary focus is directed toward onshore North American opportunities, Pioneer continues to identify and selectively evaluate other international opportunities. As a result of such foreign operations, Pioneer's financial results and international operations could be affected by factors such as changes in foreign currency exchange rates, changes in the legal or regulatory environment, weak economic conditions or changes in political or economic climates and other factors. For example:

- local political and economic developments could restrict or increase the cost of Pioneer's foreign operations,

- exchange controls and currency fluctuations could result in financial losses,

- royalty and tax increases and retroactive tax claims could increase costs of Pioneer's foreign operations,

- expropriation of the Company's property could result in loss of revenue, property and equipment,

- civil uprising, riots, terrorist attacks and wars could make it impractical to continue operations, resulting in financial losses,

- compliance with applicable U.S. law could be in conflict with the Company's contractual obligations, the laws of foreign governments or local customs,

- import and export regulations and other foreign laws or policies could result in loss of revenues,

- repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country and

- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict Pioneer's ability to fund foreign operations or may make foreign operations more costly.

Pioneer does not currently maintain political risk insurance. Pioneer evaluates on a country-by-country basis whether obtaining political risk coverage is necessary and may add such insurance in the future if the Company believes it is prudent to do so.

Argentina. During April 2006, the Company sold its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. The results of operations from the Argentine operations are being presented as discontinued operations.

During the decade of the 1990s, Argentina’s government pursued free market policies, including the privatization of state-owned companies, deregulation of the oil and gas industry, tax reforms to equalize tax rates for domestic and foreign investors, liberalization of import and export laws and the lifting of exchange controls. The cornerstone of these reforms was the 1991 convertibility law that established an exchange rate of one Argentine peso to one U.S. dollar. These policies were successful as evidenced by the elimination of inflation and substantial economic growth during the early to mid-1990s. However, throughout the decade, the Argentine government failed to balance its fiscal budget, repeatedly incurring significant fiscal deficits such that by the end of 2001 Argentina had accumulated $130 billion of debt.

During 2001, Argentina found itself in a critical economic situation with the combination of high levels of external indebtedness, a financial and banking system in crisis, a country risk rating that had reached levels beyond the historical norm, a high level of unemployment and an economic contraction that had lasted four years.

Late in 2001, the country was unable to obtain additional funding from the International Monetary Fund. Economic instability increased, resulting in substantial withdrawals of cash from the Argentine banking system over a short period of time. The government was forced to implement monetary restrictions and placed limitations on the transfer of funds out of the country without the authorization of the Central Bank of the Republic of Argentina.

In January 2002, the government defaulted on a significant portion of Argentina's $130 billion of debt and the national Congress passed Emergency Law 25,561, which, among other things, overturned the long standing, but unsustainable, convertibility plan. The government adopted a floating rate of exchange in February 2002. Two specific provisions of the Emergency Law directly impacted the Company. First, a tax on the value of hydrocarbon exports was established effective March 1, 2002. The second provision was the requirement that domestic commercial transactions, or contracts, for sales in Argentina that were previously denominated in U.S. dollars be converted to pesos (i.e., pesofication) at an exchange rate to be negotiated between sellers and buyers. Furthermore, the government placed a price freeze on gas prices at the wellhead. With the price of gas pesofied and frozen, the U.S. dollar-equivalent price of gas in Argentina fell in direct proportion to the level of devaluation.

The abandonment of the convertibility plan and the decision to allow the peso to float in international exchange markets resulted in significant devaluation of the peso. By September 30, 2002, the peso-to-U.S. dollar exchange rate had increased from 1:1 to 3.74:1. However, since the end of the third quarter of 2002, the peso-to-U.S. dollar exchange rate had stabilized at approximately 3.00:1.

As a result of the Argentine economic instability and government regulation, the Company (i) received prices for the oil and gas it produced at prices significantly below those received in its other operating areas, (ii) curtailed the investment the Company made in Argentina and (iii) ultimately led the Company to dispose of its Argentine assets. The Company is currently winding-up the affairs associated with its remaining Argentine entity. The Company is still exposed to the uncertainties surrounding the Argentine economic and political situation until the Company completes (i) the distribution of its remaining sales proceeds to the United States, (ii) the liquidation of its remaining Argentine entity and (iii) its obligations under the indemnifications and retained obligations related to the divestiture of the Argentine assets.

Africa. The Company's producing assets in Africa are in South Africa and Tunisia. The Company views the operating environment in these African nations as stable and the economic stability as good. The Company also has an exploration program in the developing West African countries of Equatorial Guinea and Nigeria. While the values of the various African nations' currencies fluctuate in relation to the U.S. dollar, the Company believes that any currency risk associated with Pioneer's African operations would not have a material impact on the Company's results of operations given that such operations are closely tied to oil prices, which are denominated in U.S. dollars.

Canada. The Company views the operating environment in Canada as stable and the economic stability as good. A portion of the Company's Canadian revenues and substantially all of its costs are denominated in Canadian dollars. While the value of the Canadian dollar fluctuates in relation to the U.S. dollar, the Company believes that any currency risk associated with its Canadian operations would not have a material impact on the Company's results of operations.

As of December 31, 2006, the Company's primary risk exposures associated with financial instruments to which it is a party include oil and gas price volatility, volatility in the exchange rates of the Canadian dollar vis á vis the U.S. dollar and interest rate volatility. The Company's primary risk exposures associated with financial instruments have not changed significantly since December 31, 2006.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

	Page
Consolidated Financial Statements of Pioneer Natural Resources Company:	
Report of Independent Registered Public Accounting Firm	64
Consolidated Balance Sheets as of December 31, 2006 and 2005	65
Consolidated Statements of Operations for the Years Ended December 31, 2006, 2005 and 2004	66
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2006, 2005 and 2004	67
Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004	69
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2006, 2005 and 2004	70
Notes to Consolidated Financial Statements	71
Unaudited Supplementary Information	109

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders of
Pioneer Natural Resources Company:

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note B to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 123(R), "Share-Based Payment" and No. 158 "Employers' Accounting for Defined Benefit Pension and Postretirement Plans."

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas
February 19, 2007

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands, except share data)

	December 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 7,033	$ 18,802
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $6,999 and $5,736 as of December 31, 2006 and 2005, respectively	195,534	334,864
Due from affiliates	3,837	1,596
Income taxes receivable	24,693	1,198
Inventories	95,131	79,659
Prepaid expenses	11,509	18,091
Deferred income taxes	82,927	158,878
Other current assets:		
Derivatives	63,665	1,246
Other, net of allowance for doubtful accounts of $6,425 as of December 31, 2005	52,229	9,470
Total current assets	536,558	623,804
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	7,967,708	8,499,253
Unproved properties	210,344	313,881
Accumulated depletion, depreciation and amortization	(1,895,408)	(2,577,946)
Total property, plant and equipment	6,282,644	6,235,188
Deferred income taxes	345	—
Goodwill	309,908	311,651
Other property and equipment, net	131,840	90,010
Other assets:		
Derivatives	4,333	1,048
Other, net of allowance for doubtful accounts of $4,045 and $92 as of December 31, 2006 and 2005, respectively	89,771	67,533
	$ 7,355,399	$ 7,329,234
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 332,795	$ 330,151
Due to affiliates	17,025	15,053
Interest payable	31,008	40,314
Income taxes payable	12,865	22,470
Other current liabilities:		
Derivatives	141,898	320,098
Deferred revenue	181,232	190,327
Other	170,156	114,942
Total current liabilities	886,979	1,033,355
Long-term debt	1,497,162	2,058,412
Derivatives	125,459	431,543
Deferred income taxes	1,172,507	767,329
Deferred revenue	483,279	664,511
Other liabilities and minority interests	205,342	156,982
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 122,686,073 and 145,200,293 shares issued at December 31, 2006 and 2005, respectively	1,227	1,452
Additional paid-in capital	2,654,047	3,775,812
Treasury stock, at cost: 1,183,090 and 18,368,109 shares at December 31, 2006 and 2005, respectively	(53,274)	(882,382)
Deferred compensation	—	(45,827)
Retained earnings (accumulated deficit)	497,488	(184,320)
Accumulated other comprehensive income (loss):		
Net deferred hedge losses, net of tax	(167,220)	(506,636)
Cumulative translation adjustment	52,403	59,003
Total stockholders' equity	2,984,671	2,217,102
Commitments and contingencies		
	$ 7,355,399	$ 7,329,234

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

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

	Year Ended December 31,		
	2006	2005	2004
Revenues and other income:			
Oil and gas	$ 1,582,049	$ 1,453,240	$ 1,012,608
Interest and other	58,723	31,531	2,157
Gain (loss) on disposition of assets, net	(7,891)	59,827	39
	1,632,881	1,544,598	1,014,804
Costs and expenses:			
Oil and gas production	398,257	346,439	224,903
Depletion, depreciation and amortization	359,523	299,944	231,598
Impairment of long-lived assets	—	644	39,684
Exploration and abandonments	264,145	163,323	113,371
General and administrative	121,830	114,237	73,192
Accretion of discount on asset retirement obligations	4,826	4,209	4,130
Interest	107,032	126,086	102,017
Hurricane activity, net	32,000	39,813	—
Other	36,280	99,437	28,398
	1,323,893	1,194,132	817,293
Income from continuing operations before income taxes	308,988	350,466	197,511
Income tax provision	(136,666)	(155,832)	(63,079)
Income from continuing operations	172,322	194,634	134,432
Income from discontinued operations, net of tax	567,409	339,934	178,422
Net income	$ 739,731	$ 534,568	$ 312,854
Basic earnings per share:			
Income from continuing operations	$ 1.39	$ 1.42	$ 1.07
Income from discontinued operations	4.56	2.48	1.43
Net income	$ 5.95	$ 3.90	$ 2.50
Diluted earnings per share:			
Income from continuing operations	$ 1.36	$ 1.40	$ 1.06
Income from discontinued operations	4.45	2.40	1.40
Net income	$ 5.81	$ 3.80	$ 2.46
Weighted average shares outstanding:			
Basic	124,359	137,110	125,156
Diluted	127,608	141,417	127,488

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except dividends per share)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Deferred Compensation	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss): Net Deferred Hedge Gains (Losses), Net of Tax	Accumulated Other Comprehensive Income (Loss): Cumulative Translation Adjustment	Total Stockholders' Equity
Balance as of January 1, 2004	$ 1,179	$ 2,734,421	$ (5,385)	$ (9,933)	$ (887,848)	$ (104,130)	$ 31,468	$ 1,759,772
Acquisition of Evergreen Resources, Inc.	254	947,334	—	(6,001)	—	—	—	941,587
Dividends declared ($.20 per common share)	—	—	—	—	(26,557)	—	—	(26,557)
Exercise of long-term incentive plan stock options and employee stock purchases	—	(2,185)	69,848	—	(32,595)	—	—	35,068
Purchase of treasury stock	—	—	(92,256)	—	—	—	—	(92,256)
Tax benefits related to stock-based compensation	—	6,612	—	—	—	—	—	6,612
Compensation costs:								
Compensation awards	5	19,122	—	(19,127)	—	—	—	—
Compensation costs included in net income	—	—	—	12,503	—	—	—	12,503
Net income	—	—	—	—	312,854	—	—	312,854
Other comprehensive income (loss):								
Deferred hedging activity, net of tax:								
Net deferred hedge losses	—	—	—	—	—	(291,642)	—	(291,642)
Net hedge losses included in continuing operations	—	—	—	—	—	79,962	—	79,962
Net hedge losses included in discontinued operations	—	—	—	—	—	74,460	—	74,460
Translation adjustment	—	—	—	—	—	—	19,417	19,417
Balance as of December 31, 2004	$ 1,438	$ 3,705,304	$ (27,793)	$ (22,558)	$ (634,146)	$ (241,350)	$ 50,885	$ 2,831,780
Dividends declared ($.22 per common share)	—	—	—	—	(30,339)	—	—	(30,339)
Exercise of long-term incentive plan stock options and employee stock purchases	—	1,310	94,670	—	(54,403)	—	—	41,577
Purchase of treasury stock	—	—	(949,259)	—	—	—	—	(949,259)
Tax benefits related to stock-based compensation	—	18,752	—	—	—	—	—	18,752
Compensation costs:								
Compensation awards	14	56,146	—	(56,160)	—	—	—	—
Compensation costs included in net income	—	—	—	26,857	—	—	—	26,857
Forfeiture of deferred compensation	—	(5,700)	—	6,034	—	—	—	334
Net income	—	—	—	—	534,568	—	—	534,568
Other comprehensive income (loss):								
Deferred hedging activity, net of tax:								
Net deferred hedge losses	—	—	—	—	—	(539,384)	—	(539,384)
Net hedge losses included in continuing operations	—	—	—	—	—	180,981	—	180,981
Net hedge losses included in discontinued operations	—	—	—	—	—	93,117	—	93,117
Translation adjustment	—	—	—	—	—	—	8,118	8,118
Balance as of December 31, 2005	$ 1,452	$ 3,775,812	$ (882,382)	$ (45,827)	$ (184,320)	$ (506,636)	$ 59,003	$ 2,217,102

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (Continued)
(in thousands, except dividends per share)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Deferred Compensation	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss): Net Deferred Hedge Gains (Losses), Net of Tax	Accumulated Other Comprehensive Income (Loss): Cumulative Translation Adjustment	Total Stockholders' Equity
Dividends declared ($.25 per share)	$ —	$ —	$ —	$ —	$ (31,726)	$ —	$ —	$ (31,726)
Conversion of senior notes	—	(85,023)	107,023	—	—	—	—	22,000
Exercise of long-term incentive plan stock options and employee stock purchases	—	4,010	39,568	—	(26,197)	—	—	17,381
Purchase of treasury stock	—	—	(348,945)	—	—	—	—	(348,945)
Tax benefits related to stock-based compensation	—	4,247	—	—	—	—	—	4,247
Compensation costs:								
Adoption of SFAS No. 123(R)	—	(45,827)	—	45,827	—	—	—	—
Compensation awards	4	(4)	—	—	—	—	—	—
Compensation costs included in net income	—	32,065	—	—	—	—	—	32,065
Net income	—	—	—	—	739,731	—	—	739,731
Retirement of shares	(229)	(1,031,233)	1,031,462	—	—	—	—	—
Other comprehensive income (loss):								
Deferred hedging activity, net of tax:								
Net deferred hedge gains	—	—	—	—	—	118,139	—	118,139
Net hedge losses included in continuing operations	—	—	—	—	—	95,005	—	95,005
Net hedge losses included in discontinued operations	—	—	—	—	—	126,272	—	126,272
Translation adjustment	—	—	—	—	—	—	(6,600)	(6,600)
Balance as of December 31, 2006	$ 1,227	$ 2,654,047	$ (53,274)	$ —	$ 497,488	$ (167,220)	$ 52,403	$ 2,984,671

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2006	**2005**	**2004**
Cash flows from operating activities:			
Net income	$ 739,731	$ 534,568	$ 312,854
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	359,523	299,944	231,598
Impairment of long-lived assets	—	644	39,684
Exploration expenses, including dry holes	148,077	53,489	39,492
Hurricane activity	75,000	39,813	—
Deferred income taxes	154,911	104,987	45,514
Loss (gain) on disposition of assets, net	7,891	(59,827)	(39)
Loss (gain) on extinguishment of debt	8,076	25,975	(95)
Accretion of discount on asset retirement obligations	4,826	4,209	4,130
Discontinued operations	(537,073)	376,952	500,458
Interest expense	11,042	4,399	(13,413)
Commodity hedge related activity	(11,498)	21,237	(45,102)
Amortization of stock-based compensation	32,065	26,857	12,503
Amortization of deferred revenue	(190,327)	(75,773)	—
Other noncash items	15,589	19,940	15,022
Change in operating assets and liabilities, net of effects from acquisitions and dispositions:			
Accounts receivable, net	121,360	(128,015)	(73,376)
Income taxes receivable	(23,495)	(1,198)	—
Inventories	(48,060)	(36,948)	(14,025)
Prepaid expenses	4,808	(7,504)	974
Other current assets, net	(42,484)	972	262
Accounts payable	(36,085)	83,960	250
Interest payable	(6,500)	(7,115)	5,533
Income taxes payable	(3,695)	8,950	3,372
Other current liabilities	(28,854)	(13,362)	(14,037)
Net cash provided by operating activities	754,828	1,277,154	1,051,559
Cash flows from investing activities:			
Payments for acquisitions, net of cash acquired	—	(965)	(880,365)
Proceeds from dispositions of assets, net of cash sold	1,644,829	1,248,581	1,709
Additions to oil and gas properties	(1,403,879)	(1,123,297)	(562,907)
Additions to other assets and other property and equipment, net	(95,435)	(39,585)	(36,970)
Net cash provided by (used in) investing activities	145,515	84,734	(1,478,533)
Cash flows from financing activities:			
Borrowings under long-term debt	1,426,490	1,203,190	1,157,903
Principal payments on long-term debt	(1,981,164)	(1,556,763)	(604,475)
Borrowings (payments) of other liabilities, net	610	(60,129)	(54,252)
Exercise of long-term incentive plan stock options and employee stock purchases	17,381	41,577	35,068
Purchase of treasury stock	(348,945)	(949,259)	(92,256)
Excess tax benefits from share-based payment arrangements	5,989	—	—
Payment of financing fees	(2,178)	(1,911)	(1,173)
Dividends paid	(31,726)	(30,339)	(26,557)
Net cash provided by (used in) financing activities	(913,543)	(1,353,634)	414,258
Net increase (decrease) in cash and cash equivalents	(13,200)	8,254	(12,716)
Effect of exchange rate changes on cash and cash equivalents	1,431	3,291	674
Cash and cash equivalents, beginning of year	18,802	7,257	19,299
Cash and cash equivalents, end of year	$ 7,033	$ 18,802	$ 7,257

The accompanying notes are an integral part of these consolidated financial statements.

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in thousands)

	Year Ended December 31,		
	2006	**2005**	**2004**
Net income	$ 739,731	$ 534,568	$ 312,854
Other comprehensive loss:			
Net deferred hedge gains (losses), net of tax:			
Net deferred hedge gains (losses)	118,139	(539,384)	(291,642)
Net hedge losses included in continuing operations	95,005	180,981	79,962
Net hedge losses included in discontinued operations	126,272	93,117	74,460
Translation adjustment	(6,600)	8,118	19,417
Other comprehensive income (loss)	332,816	(257,168)	(117,803)
Comprehensive income	$ 1,072,547	$ 277,400	$ 195,051

The accompanying notes are an integral part of these consolidated financial statements.

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company ("Pioneer" or the "Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company with current operations in the United States, Canada, Equatorial Guinea, Nigeria, South Africa and Tunisia.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries since their acquisition or formation. The Company proportionately consolidates less than 100 percent-owned affiliate partnerships, for which certain of its wholly-owned subsidiaries serve as general partners, involved in oil and gas producing activities in accordance with Emerging Issues Task Force ("EITF") Abstract Issue No. 00-1, "Investor Balance Sheet and Income Statement Display under the Equity Method for Investments in Certain Partnerships and Other Ventures". The Company owns less than a 22 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Minority interests in consolidated subsidiaries. The Company owns the majority interests in certain subsidiaries with operations in the United States and Nigeria. Associated therewith, the Company has recognized minority interests in consolidated subsidiaries of $14.4 million and $9.3 million in other liabilities and minority interests in the accompanying Consolidated Balance Sheets as of December 31, 2006 and 2005, respectively.

Minority interests in the net losses of the Company's consolidated Nigerian subsidiary totaled $4.9 million and $5.2 million for the years ended December 31, 2006 and 2005, respectively, and are included in interest and other income in the accompanying Consolidated Statements of Operations. Minority interests in the net income of the Company's consolidated United States subsidiaries totaled $2.6 million, $3.5 million and $.9 million for the years ended December 31, 2006, 2005 and 2004, respectively, and are included in other expense in the accompanying Consolidated Statements of Operations.

Discontinued operations. During 2005 and 2006, the Company sold its interests in the following oil and gas asset groups:

Country	Description of Asset Groups	Date Divested
Canada	Martin Creek, Conroy Black and Lookout Butte fields	May 2005
United States	Two Gulf of Mexico shelf fields	August 2005
United States	Deepwater Gulf of Mexico fields	March 2006
Argentina	Argentine assets	April 2006

In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"), the Company has reflected the results of operations of the above divestitures as discontinued operations, rather than as a component of continuing operations. See Note V for additional information regarding discontinued operations.

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Depletion of oil and gas properties and impairment of goodwill and oil and gas properties, in part, is determined using estimates of proved oil and gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves; commodity price outlooks; foreign laws, restrictions and currency exchange rates; and export and excise taxes. Actual results could differ from the estimates and assumptions utilized.

Argentina. In April 2006, the Company sold its Argentine assets and is currently winding-up the affairs associated with its remaining Argentine entity. As of December 31, 2006 and 2005, the Company used exchange rates of 3.06 pesos to $1 and 3.03 pesos to $1, respectively, to remeasure the peso-denominated monetary assets and liabilities of the Company's Argentine subsidiaries. The Company remains exposed to uncertainties surrounding the Argentine economic and political environment until the Company completes (i) the distribution of its remaining sales proceeds to the United Sates, (ii) the liquidation of its remaining Argentine entity and (iii) its obligations under the indemnifications and retained obligations related to the divesture of the Argentine assets.

Cash equivalents. Cash and cash equivalents include cash on hand and depository accounts held by banks.

Investments. Investments in unaffiliated equity securities that have a readily determinable fair value are classified as "trading securities" if management's current intent is to hold them for the near term; otherwise, they are accounted for as "available-for-sale" securities. The Company reevaluates the classification of investments in unaffiliated equity securities at each balance sheet date. The carrying value of trading securities and available-for-sale securities are adjusted to fair value as of each balance sheet date.

Unrealized holding gains are recognized for trading securities in interest and other income, and unrealized holding losses are recognized in other expense during the periods in which changes in fair value occur.

Unrealized holding gains and losses are recognized for available-for-sale securities as credits or charges to stockholders' equity and other comprehensive income (loss) during the periods in which changes in fair value occur. Realized gains and losses on the divestiture of available-for-sale securities are determined using the average cost method. The Company had no investments in available-for-sale securities as of December 31, 2006 or 2005.

Investments in unaffiliated equity securities that do not have a readily determinable fair value are measured at the lower of their original cost or the net realizable value of the investment. The Company had no significant equity security investments that did not have a readily determinable fair value as of December 31, 2006 or 2005.

Inventories. Inventories were comprised of $93.7 million and $77.3 million of materials and supplies and $1.4 million and $2.4 million of commodities as of December 31, 2006 and 2005, respectively. The Company's materials and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials and parts. The materials and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or market, on a weighted average cost basis. Commodities inventory is carried at the lower of average cost or market, on a first-in, first-out basis. Any impairments of inventory are reflected in gain (loss) on disposition of assets in the Consolidated Statements of Operations. As of December 31, 2006 and 2005, the Company's materials and supplies inventory was net of $4.2 million and $.2 million, respectively, of valuation reserve allowances.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company capitalizes interest on expenditures for significant development projects, generally when the underlying project is sanctioned, until such projects are ready for their intended use.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its Consolidated Balance Sheets for more than one year following the completion of drilling unless the exploratory well finds oil and gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well.

(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain Alaskan, deepwater Gulf of Mexico and foreign projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is impaired. See Note D for additional information regarding the Company's suspended exploratory well costs.

The Company owns interests in seven natural gas processing plants and seven treating facilities. The Company operates five of the plants and all seven treating facilities. The Company's ownership interests in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. Third party revenues generated from the plant and treating facilities for the three years ended December 31, 2006, 2005 and 2004 were $38.5 million, $39.2 million and $32.1 million, respectively. Third party expenses attributable to the plants and treating facilities for the same respective periods were $6.4 million, $13.8 million and $11.8 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

Capitalized costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. Costs of significant nonproducing properties, wells in the process of being drilled and development projects are excluded from depletion until such time as the related project is completed and proved reserves are established or, if unsuccessful, impairment is determined.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion, depreciation and amortization. Generally, no gain or loss is recognized until the entire amortization base is sold. However, gain or loss is recognized from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base.

In accordance with SFAS No. 144, the Company reviews its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

Unproved oil and gas properties are periodically assessed for impairment on a project-by-project basis. The impairment assessment is affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. If the quantity of potential reserves determined by such evaluations is not sufficient to fully recover the cost invested in each project, the Company will recognize an impairment loss at that time by recording an allowance.

Goodwill. As described in Note C, the Company recorded $327.8 million of goodwill associated with the merger with Evergreen Resources, Inc. ("Evergreen"). The goodwill was recorded to the Company's United States reporting unit. In accordance with EITF Abstract Issue No. 00-23, "Issues Related to the Accounting for Stock Compensation under APB Opinion No. 25 and FASB Interpretation No. 44", the Company has reduced goodwill by $18.0 million since September 28, 2004 for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the Evergreen merger. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets", goodwill is not amortized to earnings, but is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. If the carrying value of goodwill is determined to be impaired, it is reduced for the impaired value with a corresponding charge to pretax earnings in the period in which it is determined to be impaired. During the third quarter of 2006, the Company performed its annual assessment of impairment of the goodwill and determined that there was no impairment.

Other property, plant and equipment, net. Other property, plant and equipment is stated at cost and primarily consists of items such as heavy equipment and rigs, furniture and fixtures and leasehold improvements. Depreciation is provided over the estimated useful life of the assets using the straight-line method. At December 31, 2006 and 2005, other property, plant and equipment was net of accumulated depreciation of $145.3 million and $131.5 million, respectively.

Asset retirement obligations. The Company accounts for asset retirement obligations in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). SFAS 143 amended SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies" to require that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Under the provisions of SFAS 143, asset retirement obligations are generally capitalized as part of the carrying value of the long-lived asset.

In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143" ("FIN 47"). FIN 47 clarifies that conditional asset retirement obligations meet the definition of liabilities and should be recognized when incurred if their fair values can be reasonably estimated. The interpretation was adopted by the Company on December 31, 2005. The adoption of FIN 47 had no impact on the Company's financial position or results of operations.

Derivatives and hedging. The Company follows the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"). SFAS 133 requires the accounting recognition of all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through net income. Under the provisions of SFAS 133, the Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a "fair value hedge") or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a "cash flow hedge"). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative hedge contract or by effectiveness assessments using statistical measurements. The Company's policy is to assess hedge effectiveness at the end of each calendar quarter.

Under the provisions of SFAS 133, changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities, or firm commitments through net income. Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in accumulated other comprehensive income (loss) - net deferred hedge losses, net of tax ("AOCI - Hedging") in the stockholders' equity section of the Company's Consolidated Balance Sheets until such time as the hedged items are recognized in net income. Ineffective portions of a derivative instrument's change in fair value are immediately recognized in earnings.

See Note J for a description of the specific types of derivative transactions in which the Company participates.

Environmental. The Company's environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Expenditures that extend the life of the related property or mitigate or prevent future environmental contamination are capitalized. Liabilities are recorded when environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are undiscounted unless the timing of cash payments for the liability is fixed or reliably determinable.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held. During 2006, the Company retired 22.9 million treasury shares resulting in a reduction in treasury stock of $1.0 billion.

Revenue recognition. The Company does not recognize revenues until they are realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectibility is reasonably assured.

The Company uses the entitlements method of accounting for oil, natural gas liquid ("NGL") and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying Consolidated Balance Sheets.

The Company had no material oil or NGL entitlement assets or liabilities as of December 31, 2006 or 2005. The following table presents the Company's gas entitlement assets and liabilities and their associated volumes as of December 31, 2006 and 2005:

	December 31,			
	2006		2005	
	Amount	MMcf	Amount	MMcf
	($ in millions)			
Entitlement assets	$ 13.0	4,201	$ 12.1	4,007
Entitlement liabilities	$ 3.9	1,082	$ 8.5	7,206

Stock-based compensation. On January 1, 2006, the Company adopted SFAS No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123(R)") to account for stock-based compensation. Among other items, SFAS 123(R) eliminates the use of the Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"), intrinsic value method of accounting and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in the financial statements. The Company elected to use the modified prospective method for adoption of SFAS 123(R), which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested stock options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value on the date of grant, was recognized in the Company's financial statements over their remaining vesting periods, which ended in August 2006. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant, is being recognized in the Company's financial statements over the vesting period. The Company utilizes the Black-Scholes option pricing model to measure the fair value of stock options and utilizes the stock price on the date of grant for the fair value of restricted stock awards. Prior to the adoption of SFAS 123(R), the Company followed the intrinsic value method in accordance with APB 25 to account for stock options. Prior period financial statements have not been restated. The modified prospective method requires the Company to estimate forfeitures in calculating the expense related to stock-based compensation as opposed to its prior policy of recognizing forfeitures as they occurred. The Company recorded no cumulative effect as a result of adopting SFAS 123(R).

Additionally, under the provisions of SFAS 123(R), deferred compensation recorded under APB 25 related to equity-based awards should be eliminated against the appropriate equity accounts. As a result, upon adoption of SFAS 123(R), the Company eliminated $45.8 million of deferred compensation cost in stockholders' equity and reduced a like amount of additional paid-in capital in the accompanying Consolidated Balance Sheets.

For the year ended December 31, 2006, the Company recorded $32.1 million of compensation costs for all stock-based plans. The impact to net income of adopting SFAS 123(R) was $1.6 million for the year ended December 31, 2006, or less than $.02 per diluted share. For the year ended December 31, 2006, the adoption impact is comprised of $959 thousand of compensation expense associated with stock options and $669 thousand of compensation expense associated with the Company's Employee Stock Purchase Plan (the "ESPP"), which is a compensatory plan under the provisions of SFAS 123(R).

Pursuant to the provisions of SFAS 123(R), the Company's issued shares, as reflected in the accompanying Consolidated Balance Sheets at December 31, 2006 and 2005, do not include 1,946,211 shares and 1,756,180 shares, respectively, related to unvested restricted stock awards.

As of December 31, 2006, there was approximately $39.8 million of unrecognized compensation expense related to unvested share-based compensation plan awards, primarily related to restricted stock awards. This compensation will be recognized on a straight-line basis over the remaining vesting periods of the awards, which is a remaining period of less than three years.

The following table illustrates the pro forma effect on net income and net income per share as if the Company had applied the fair value recognition provisions of SFAS No. 123(R) to stock-based compensation during the years ended December 31, 2005 and 2004:

	Year Ended December 31,	
	2005	2004
	(in thousands, except per share amounts)	
Net income, as reported	$ 534,568	$ 312,854
Plus: Stock-based compensation expense included in net income for all awards, net of tax (a)	17,054	7,939
Deduct: Stock-based compensation expense determined under fair value based method for all awards, net of tax (a)	(19,772)	(13,985)
Pro forma net income	$ 531,850	$ 306,808
Net income per share:		
Basic – as reported	$ 3.90	$ 2.50
Basic – pro forma	$ 3.88	$ 2.45
Diluted – as reported	$ 3.80	$ 2.46
Diluted – pro forma	$ 3.78	$ 2.41

(a) For the years ended December 31, 2005 and 2004, stock-based compensation expense included in net income is net of tax benefits of $9.8 million and $4.6 million, respectively. Similarly, stock-based compensation expense determined under the fair value based method for the years ended December 31, 2005 and 2004 is net of tax benefits of $11.4 million and $8.0 million, respectively. See Note P for additional information regarding the Company's income taxes.

Foreign currency translation. The U.S. dollar is the functional currency for all of the Company's international operations except Canada. Accordingly, monetary assets and liabilities denominated in a foreign currency are remeasured to U.S. dollars at the exchange rate in effect at the end of each reporting period; revenues and costs and expenses denominated in a foreign currency are remeasured at the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from remeasuring foreign currency denominated balances into U.S. dollars are recorded in other income or other expense, respectively. Nonmonetary assets and liabilities denominated in a foreign currency are remeasured at the historic exchange rates that were in effect when the assets or liabilities were acquired or incurred.

The functional currency of the Company's Canadian operations is the Canadian dollar. The financial statements of the Company's Canadian subsidiaries are translated to U.S. dollars as follows: all assets and liabilities are translated using the exchange rate in effect at the end of each reporting period; revenues and costs and expenses are translated using the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from translating non-U.S. dollar denominated balances are recorded in the accompanying Consolidated Statements of Stockholders' Equity for the period through accumulated other comprehensive income (loss) - cumulative translation adjustment.

The following table presents the exchange rates used to translate the financial statements of the Company's Canadian subsidiaries in the preparation of the consolidated financial statements as of and for the years ended December 31, 2006, 2005 and 2004:

	December 31,		
	2006	**2005**	**2004**
U.S. Dollar from Canadian Dollar – Balance Sheets	.8577	.8606	.8320
U.S. Dollar from Canadian Dollar – Statements of Operations	.8817	.8279	.7699

Reclassifications. Certain reclassifications have been made to the 2005 and 2004 amounts in order to conform with the 2006 presentation. Specifically, the Company reduced its exploration and abandonments expense by $39.8 million for the year ended December 31, 2005, which represents reclassification of abandonment costs for the Company's East Cameron facility destroyed by Hurricane Rita to hurricane activity, net expense on the accompanying Consolidated Statements of Operations and Consolidated Statements of Cash Flows. Additionally, $18.2 million of unfunded check issuances were reclassified from changes in accounts payable in operating cash flows to payment of other liabilities in net cash flows from financing activities within the Consolidated Statements of Cash Flows for the year ended December 31, 2005.

New accounting pronouncements. The following discussions provide information about new accounting pronouncements that were issued by FASB during 2006:

FIN 48. In July 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). The Interpretation clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on measurement, classification, interim accounting and disclosure. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company is continuing to assess the potential impacts of this Interpretation.

SFAS 157. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measures" ("SFAS 157"). SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measures required under other accounting pronouncements, but does not change existing guidance as to whether or not an instrument is carried at fair value. SFAS 157 is effective for fiscal years beginning after November 15, 2007. The Company is continuing to assess the impact, if any, of SFAS 157**.**

SFAS 158. In September 2006, the FASB issued SFAS 158, "Employers' Accounting for Defined Benefit Pension and other Postretirement Plans" ("SFAS 158"). Under SFAS 158, a business entity that sponsors one or more single-employer defined benefit plans is required to:

- recognize the funded status of a benefit plan in its balance sheet, measured as the difference between plan assets at fair value (with limited exceptions) and the benefit obligation,
- recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost,
- measure defined benefit plan assets and obligations as of the date of the employer's balance sheet and
- disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and transition assets or obligations.

An employer with publicly traded securities is required to initially recognize the funded status of its defined benefit postretirement plans and to provide the required disclosures as of the end of the first fiscal year ending after December 15, 2006. The Company adopted the provisions of SFAS 158 effective on December 31, 2006. The Company previously recognized the funded status of its defined benefit postretirement plans and currently recognizes periodic changes in its defined benefit postretirement plans as components of service costs in the period of change as allowed by SFAS 158. Consequently, the adoption of SFAS 158 did not have a material impact on the Company's liquidity, financial position or future results of operations. See Note H of Notes to Consolidated Financial Statements in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's postretirement plans.

NOTE C. Acquisitions

Evergreen merger. On September 28, 2004, Pioneer completed a merger with Evergreen, with Pioneer being the surviving corporation for accounting purposes. The transaction was accounted for as a purchase of Evergreen by Pioneer. As a result, the financial statements for the Company prior to September 28, 2004 are those of Pioneer only. The merger with Evergreen was accomplished through the issuance of 25.4 million shares of Pioneer common stock and $851.1 million of cash paid to Evergreen shareholders at closing, net of $12.1 million of acquired cash. The cash consideration paid in the merger was financed through borrowings on the Company's credit facilities.

The Company recorded $327.8 million of goodwill associated with the Evergreen merger, which represented the excess of the purchase consideration over the net fair value of the identifiable net assets acquired.

Permian Basin and Onshore Gulf Coast acquisitions. During 2006 and 2005, the Company spent $71.2 million and $167.8 million, respectively, to acquire various working interests in the Spraberry and South Texas areas.

NOTE D. Exploratory Well Costs

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in proved properties in the Consolidated Balance Sheets. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Beginning capitalized exploratory well costs	$ 198,291	$ 126,472	$ 108,986
Additions to exploratory well costs pending the determination of proved reserves	451,109	243,272	156,937
Reclassifications due to determination of proved reserves	(193,480)	(78,334)	(56,639)
Disposition of wells sold	(52,628)	—	—
Exploratory well costs charged to exploration expense	(138,239)	(93,119)	(82,812)
Ending capitalized exploratory well costs	$ 265,053	$ 198,291	$ 126,472

The following table provides an aging as of December 31, 2006, 2005 and 2004 of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the date the drilling was completed:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands, except well counts)	
Capitalized exploratory well costs capitalized:			
One year or less	$ 126,749	$ 84,042	$ 35,046
More than one year	138,304	114,249	91,426
	$ 265,053	$ 198,291	$ 126,472
Number of wells with exploratory well costs that have been capitalized for a period greater than one year	14	14	10

The following table provides the capitalized costs of exploration projects that have been suspended for more than one year as of December 31, 2006, 2005 and 2004:

	December 31,		
	2006	2005	2004
		(in thousands)	
United States:			
Clipper (a)	$ 75,242	$ —	$ —
Ozona Deep	—	19,423	19,462
Oooguruk	52,205	52,205	47,083
Thunder Hawk	—	25,769	—
United States – other	4,103	—	—
Canada – other	1,695	805	1,214
South Africa	—	7,227	14,895
Tunisia – Anaguid	5,059	8,820	8,772
Total	$ 138,304	$ 114,249	$ 91,426

(a) Includes $37.0 million of costs incurred in 2006.

The following discussion describes the history and status of each significant suspended exploratory project:

Clipper. During 2005, the Company drilled its first exploratory well on the Clipper prospect, which was a discovery. During 2006, the Company drilled additional wells to determine the magnitude of the discovery. The Company is currently evaluating the plans for development of the discovery, including evaluating sub-sea tie-back options to third-party production and handling facilities in the area.

Ozona Deep and Thunder Hawk. During March 2006, the Company sold its interests in the Ozona Deep and Thunder Hawk properties as part of the Company's deepwater Gulf of Mexico divestiture. See Note N for additional information regarding the Company's divestiture of its deepwater Gulf of Mexico oil and gas assets.

Oooguruk. During 2003, the Company's Alaskan Oooguruk discovery wells found quantities of oil believed to be commercial. In 2003, the Company began farm-in discussions with the owner of undeveloped discoveries in adjacent acreage given its proximity and the potential cost benefits of a larger scale project. The farm-in was completed during 2004. Along with completing the farm-in agreement, Pioneer obtained access to exploration well and seismic data to improve the Company's understanding of the potential of the discoveries without having to drill additional wells. In late 2004, the Company completed an extensive technical and economic evaluation of the resource potential and a front-end engineering design study ("FEED study") for the area.

During the first quarter of 2006, the Company sanctioned the development of the discovery and obtained the necessary regulatory approvals. The Company installed an offshore gravel drilling and production site during the 2006 winter construction season and completed armoring activities during the third quarter. A sub-sea flowline and facilities will be installed during 2007 to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit. Pioneer plans to drill approximately 40 horizontal wells to develop the discovery. Depending on weather conditions and facilities completion and accessibility, drilling could begin as early as the fall of 2007. The Company estimates first production will occur in 2008.

South Africa. During 2001, the Company drilled two South African discovery wells that found quantities of gas and condensate believed to be commercial. From 2002 to 2004, the Company actively reviewed the gas supply and demand fundamentals in South Africa and had discussions with a gas-to-liquids ("GTL") plant in the area to purchase the condensate and gas. During 2004, a FEED study was authorized for the gas development and infrastructure design. The FEED study was completed in early 2005 and based on that study, the GTL plant operator initiated purchase orders for long-lead time infrastructure components. In December 2005, the Company announced the final approvals with its partner in the South Coast gas project to commence the initial development of the project. As a result, the Company added 11.4 million Bbls oil equivalent ("MMBOE") of proved reserves in 2005 and reduced the suspended exploratory costs by $7.7 million.

During 2000, the Company drilled two South African exploratory wells in the Company's Boomslang prospect. One well was unsuccessful, but the other well found quantities of hydrocarbons believed to be commercial. The Boomslang discovery was not included in the initial development phase of the South Coast Gas project. Boomslang is an oil discovery with a significant gas cap. The Company believes the Boomslang discovery may ultimately be developed as a gas discovery, but commercialization plans have not progressed sufficiently to allow the Company to continue to capitalize the exploratory costs related to the discovery. Accordingly, the Company expensed the Boomslang discovery in the fourth quarter of 2006.

Tunisia - Anaguid. During 2003, the Company drilled two exploration wells on its Anaguid Block in Tunisia which found quantities of condensate and gas believed to be commercial. During 2004, the wells were scheduled and approved for extended production tests. However, the project operator delayed the extended production tests due to issues unrelated to the Company or the project. During 2005, the project operator, along with the Company, conducted an extended production test of one of the two existing exploration wells and drilled an offset appraisal well to the other exploration well.

The results of the extended production test were unfavorable and the Company expensed $5.1 million associated with this well in 2005. However, the appraisal well offsetting the second discovery encountered gas and condensate in a similar horizon to the initial well. The Company has concluded studies on the appraisal well with unfavorable results and expensed $4.2 million in the fourth quarter of 2006. Studies on the second discovery will continue to determine whether development is economical.

NOTE E. Disclosures About Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2006 and 2005:

	December 31,			
	2006		2005	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Net derivative contract liabilities:				
Commodity price hedges	$ (68,228)	$ (68,228)	$ (748,477)	$ (748,477)
Terminated commodity price hedges	$ (131,131)	$ (131,131)	$ (870)	$ (870)
Financial assets:				
Trading securities	$ 18,582	$ 18,582	$ 15,237	$ 15,237
Notes receivable due 2008 to 2011	$ 23,607	$ 23,607	$ 1,429	$ 1,429
Financial liabilities – long-term debt:				
Line of credit	$ (328,000)	$ (328,000)	$ (900,000)	$ (900,000)
8 1/4 % senior notes due 2007	$ (32,081)	$ (32,511)	$ (32,199)	$ (33,477)
6 1/2 % senior notes due 2008	$ (3,761)	$ (3,798)	$ (348,714)	$ (356,965)
5 7/8% senior notes due 2012	$ (6,235)	$ (5,903)	$ (6,255)	$ (5,947)
5 7/8% senior notes due 2016	$ (427,588)	$ (497,054)	$ (421,327)	$ (506,590)
6 7/8% senior notes due 2018	$ (449,579)	$ (452,430)	$ —	$ —
4 3/4 % senior convertible notes due 2021	$ —	$ —	$ (100,000)	$ (201,225)
7 1/5% senior notes due 2028	$ (249,918)	$ (253,150)	$ (249,917)	$ (265,200)

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Commodity price swap and collar contracts, interest rate swaps and foreign currency swap contracts. The fair value of commodity price swap and collar contracts, interest rate swaps and foreign currency contracts are estimated from quotes provided by the counterparties to these derivative contracts and represent the estimated amounts that the Company would expect to receive or pay to settle the derivative contracts. See Note J for a description of each of these derivatives, including whether the derivative contract qualifies for hedge accounting treatment or is considered a speculative derivative contract.

Financial assets. The carrying amounts of the trading securities approximate fair value due to the short maturity of these instruments. The fair value of the notes receivable approximates the carrying value at December 31, 2006 due to the proximity of the execution dates of the notes to December 31. The current portion of the notes receivable, amounting to $5.1 million and $.4 million as of December 31, 2006 and 2005, respectively, is included in other current assets, net in the Company's Consolidated Balance Sheets. The trading securities and the noncurrent portions of the notes receivable are included in other assets, net in the Company's Consolidated Balance Sheets.

Long-term debt. The carrying amount of borrowings outstanding under the Company's corporate credit facility approximates fair value because these instruments bear interest at variable market rates. The fair values of each of the senior note issuances were determined based on quoted market prices for each of the issues. See Note F for additional information regarding the Company's long-term debt.

NOTE F. Long-term Debt

Long-term debt, including the effects of net deferred fair value hedges losses and issuance discounts and premiums, consisted of the following components at December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
	(in thousands)	
Outstanding debt principal balances:		
Line of credit	$ 328,000	$ 900,000
8 1/4% senior notes due 2007	32,075	32,075
6 1/2% senior notes due 2008	3,777	350,000
5 7/8% senior notes due 2012	6,110	6,110
5 7/8% senior notes due 2016	526,875	526,875
6 7/8% senior notes due 2018	450,000	—
4 3/4% senior convertible notes due 2021	—	100,000
7 1/5% senior notes due 2028	250,000	250,000
	1,596,837	2,165,060
Issuance discounts and premiums, net	(96,284)	(102,347)
Net deferred fair value hedge losses	(3,391)	(4,301)
Total long-term debt	$ 1,497,162	$ 2,058,412

Lines of credit. The Company has an Amended and Restated 5-Year Revolving Credit Agreement (the "Credit Agreement"), which originally had a maturity date in September 2010 unless extended in accordance with the terms of the Credit Agreement. The terms of the Credit Agreement provide for initial aggregate loan commitments of $1.5 billion, which may be increased to a maximum aggregate amount of $1.8 billion if the lenders increase their loan commitments or if loan commitments of new financial institutions are added to the Credit Agreement. Effective September 29, 2006, participating lenders extended the maturity date on $1.395 billion of aggregate loan commitments under the Credit Agreement to September 2011.

Borrowings under the Credit Agreement may be in the form of revolving loans or swing line loans. Aggregate outstanding swing line loans may not exceed $100 million. Revolving loans bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank (8.25 percent per annum at December 31, 2006) or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day (5.17 percent per annum at December 31, 2006) plus .5 percent or (b) a base Eurodollar rate, substantially equal to LIBOR (5.33 percent per annum at December 31, 2006), plus a margin (the "Applicable Margin") that is determined by reference to a grid based on the Company's debt rating (.875 percent per annum at December 31, 2006). The Applicable Margin is increased by .10 percent to .125 percent per annum, depending on the Company's debt ratings, if total borrowings under the Credit Agreement exceed 50 percent of the aggregate loan commitments. Swing line loans bear interest at a rate per annum equal to the "ASK" rate for Federal funds periodically published by the Dow Jones Market Service plus the Applicable Margin. The Company pays commitment fees on the undrawn amounts under the Credit Agreement that are determined by reference to a grid based on the Company's debt rating (.175 percent per annum at December 31, 2006).

As of December 31, 2006, the Company had $153.8 million of undrawn letters of credit, of which $150.2 million were undrawn commitments under the Credit Agreement. The letters of credit outstanding under the Credit Agreement are subject to a per annum fee, based on a grid of the Company's debt rating, representing the Company's LIBOR margin (.875 percent at December 31, 2006) plus .125 percent. As of December 31, 2006, the Company had unused borrowing capacity of $1.0 billion under the Credit Agreement.

The Credit Agreement contains certain financial covenants, which include the (i) maintenance of a ratio of the Company's earnings before gain or loss on the disposition of assets, interest expense, income taxes, depreciation, depletion and amortization expense, exploration and abandonments expense and other noncash charges and expenses to consolidated interest expense of at least 3.5 to 1.0; (ii) maintenance of a ratio of total debt to book capitalization less intangible assets, accumulated other comprehensive income and certain noncash asset impairments not to exceed .60 to 1.0; and (iii) maintenance of an annual ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.50 to 1.0 through March 2007 and 1.75 to 1.0 thereafter. The lenders may declare any outstanding obligations under the Credit Agreement immediately due and payable upon the occurrence, and during the continuance of, an event of default, which includes a defined change in control of the Company. As of December 31, 2006, the Company was in compliance with all of its debt covenants.

Senior notes. During May 2006, the Company issued $450 million of 6.875% notes and received proceeds, net of issuance discount and underwriting cost, of $447.4 million.

The Company's senior notes are general unsecured obligations ranking equally in right of payment with all other senior unsecured indebtedness of the Company and are senior in right of payment to all existing and future subordinated indebtedness of the Company. The Company is a holding company that conducts all of its operations through subsidiaries; consequently, the senior notes are structurally subordinated to all obligations of its subsidiaries. Interest on the Company's senior notes is payable semiannually.

Senior convertible notes. During 2006, holders of all of the $100 million of 4 3/4% Senior Convertible Notes exercised their conversion rights. Associated therewith, the Company paid $79.9 million in cash, issued 2.3 million shares of common stock and recorded a $22 million increase to stockholders' equity.

Early extinguishment of debt. During 2006, the Company repurchased $346.2 million of its outstanding $350 million of 6.50% senior notes due 2008 (the "6.50% Notes"). The Company recognized a charge of $8.1 million in the second quarter of 2006 associated with the early extinguishment of the 6.50% Notes, which is included in other expense in the accompanying Consolidated Statements of Operations. During 2005, the Company (i) redeemed the remaining principal amounts of its outstanding 9 5/8% senior notes due 2010 and its 7.50% senior notes due 2012 of $64.0 million and $16.2 million, respectively, and (ii) accepted tenders to purchase for cash $188.4 million in principal amount of its 5 7/8% senior notes due 2012. Consequently, the Company recognized a charge for the early extinguishment of debt of $26.5 million included in other expense in the accompanying Consolidated Statements of Operations on these redemptions and tenders for 2005.

Principal maturities. Principal maturities of long-term debt at December 31, 2006 are as follows (in thousands):

2007	$	32,075
2008	$	3,777
2009	$	—
2010	$	22,960
2011	$	305,040
Thereafter	$	1,232,985

Interest expenses. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Cash payments for interest	$ 114,727	$ 129,868	$ 109,970
Accretion/amortization of discounts or premiums on loans	7,133	6,186	3,683
Accretion of discount on derivative obligations	2,529	—	—
Amortization of net deferred hedge (gains) losses (see Note J)	14	(4,052)	(19,220)
Amortization of capitalized loan fees	1,366	2,265	2,059
Kansas ad valorem tax	—	—	65
Net changes in accruals	(6,571)	(7,092)	7,476
Interest incurred	119,198	127,175	104,033
Less capitalized interest	(12,166)	(1,089)	(2,016)
Total interest expense	$ 107,032	$ 126,086	$ 102,017

NOTE G. Related Party Transactions

The Company, through a wholly-owned subsidiary, serves as operator of properties in which it and its affiliated partnerships have an interest. Accordingly, the Company receives producing well overhead, drilling well overhead and other fees related to the operation of the properties. The affiliated partnerships also reimburse the Company for their allocated share of general and administrative charges. Reimbursements of fees are recorded as reductions to general and administrative expenses in the Company's Consolidated Statements of Operations.

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 1,551	$ 1,493	$ 1,458
Reimbursement of general and administrative expenses	$ 348	$ 348	$ 193

NOTE H. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors (the "Board") approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary and 100 percent of their annual bonus. The Company will provide a matching contribution of 100 percent of the officer’s and key employee's contribution limited to the first 10 percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan. The Company's matching contributions were $1.3 million, $1.2 million and $.9 million for the years ended December 31, 2006, 2005 and 2004, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. ("Pioneer USA") 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount of not less than two percent nor more than 30 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's base compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four-year period that begins with the participant's date of hire. During the years ended December 31, 2006, 2005 and 2004, the Company recognized compensation expense of $9.3 million, $8.0 million and $5.4 million, respectively, as a result of Matching Contributions.

Long-Term Incentive Plan

In May 2006, the Company's stockholders approved a new Long-Term Incentive Plan, which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, performance units and restricted stock to directors, officers and employees of the Company. The Long-Term Incentive Plan provides for the issuance of 4.6 million awards.

The following table shows the number of awards available under the Company's Long-Term Incentive Plan at December 31, 2006:

Approved and authorized awards	4,600,000
Awards issued after May 3, 2006	(74,549)
Awards available for future grant	4,525,451

For the 2006-2007 director year, the Company's non-employee directors were offered a choice to receive their annual fee retainers (i) 100 percent in restricted stock units, (ii) 100 percent in cash or (iii) a combination of 50/50 of cash and restricted stock units. All non-employee directors also received an annual equity grant of restricted stock units.

Stock option awards. In accordance with the Evergreen merger agreement, on September 28, 2004, the Company assumed fully-vested options to purchase 2,384,657 shares of the Company's common stock at various exercise prices, the weighted average price per share of which was $11.18. The assumed options were outstanding awards to Evergreen employees when the Evergreen merger occurred.

During 2004, the Company's stock-based compensation philosophy shifted its emphasis from the awarding of stock options to restricted stock awards. There were no options granted after 2003.

Restricted stock awards. During 2006, 2005 and 2004 the Company issued 736,642, 1,411,269 and 630,937, respectively, restricted shares of the Company's common stock as compensation to directors, officers and employees of the Company.

During 2004, the Company assumed 214,186 restricted stock units in exchange for Evergreen restricted stock units outstanding on September 28, 2004. The Company recorded $6.0 million of deferred compensation for future expected service associated with certain of the restricted stock units assumed from Evergreen. The deferred compensation was amortized as charges to compensation expense over the periods in which the restrictions on the units lapsed.

Compensation costs. On January 1, 2006, the Company adopted SFAS 123(R), as more fully described in Note B, and eliminated $45.8 million of deferred compensation in stockholders' equity and reduced a like amount of additional paid-in capital in the Consolidated Balance Sheets. Prior to adoption of SFAS 123(R), the Company recorded $56.2 million and $19.1 million of deferred compensation associated with restricted stock awards in stockholders' equity during 2005 and 2004, respectively. Such amounts will be amortized to compensation expense over the vesting periods of the awards.

Adoption of SFAS 123(R), required the Company to prospectively (i) recognize the value of the unvested stock options, which was approximately $959 thousand and (ii) recognize compensation expense associated with the Company's ESPP. The Company's recognition of compensation of restricted stock did not change upon adoption of SFAS 123(R).

During 2006, 2005 and 2004, the Company recognized compensation costs associated with stock-based compensation of $32.1 million, $26.9 million and $12.5 million, respectively. At December 31, 2006, the Company has unrecognized unvested stock-based compensation costs of approximately $39.8 million, which will amortize to earnings over the next three years.

The following table reflects the outstanding restricted stock awards as of December 31, 2006, 2005 and 2004 and activity related thereto for the years then ended:

	Year Ended December 31,					
	2006		2005		2004	
	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price
Restricted stock awards:						
Outstanding at beginning of year	1,966,223	$ 36.90	1,447,987	$ 28.46	676,973	$ 24.79
Evergreen awards assumed	—	$ —	—	$ —	214,186	$ 32.58
Shares granted	736,642	$ 43.44	1,411,269	$ 39.79	630,937	$ 31.29
Shares forfeited	(190,538)	$ 39.32	(174,046)	$ 33.99	(32,174)	$ 30.99
Lapse of restrictions	(385,780)	$ 34.84	(718,987)	$ 26.26	(41,935)	$ 31.09
Outstanding at end of year	2,126,547	$ 39.32	1,966,223	$ 36.90	1,447,987	$ 28.46

A summary of the Company's stock option plans as of December 31, 2006, 2005 and 2004, and changes during the years then ended, are presented below:

	Year Ended December 31,					
	2006		2005		2004	
	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price
Non-statutory stock options (a):						
Outstanding at beginning of year	2,685,398	$ 20.32	5,180,584	$ 18.60	5,274,116	$ 20.13
Evergreen options assumed	—	$ —	—	$ —	2,384,657	$ 11.18
Options forfeited	(267,851)	$ 22.60	(65,190)	$ 22.94	(102,890)	$ 22.24
Options exercised	(816,052)	$ 19.22	(2,429,996)	$ 15.95	(2,375,299)	$ 14.39
Outstanding at end of year	1,601,495	$ 20.50	2,685,398	$ 20.32	5,180,584	$ 18.60
Exercisable at end of year	1,601,495	$ 20.50	2,382,714	$ 19.74	3,970,996	$ 17.08

(a) The Company did not grant any stock options during 2006, 2005 or 2004.

The following table summarizes information about the Company's stock options outstanding and exercisable at December 31, 2006:

	Options Outstanding and Exercisable			
Range of Exercise Price	**Number Outstanding at December 31, 2006**	**Weighted Average Remaining Contractual Life**	**Weighted Average Exercise Price**	**Intrinsic Value at December 31, 2006**
				(in thousands)
$5-$11	139,402	2.0 years	$ 9.90	$ 4,153
$12-$18	691,611	2.1 years	$ 17.50	15,347
$19-$26	755,483	3.2 years	$ 24.81	11,242
$31-$43	14,999	0.1 years	$ 40.31	—
	1,601,495			$ 30,742

Employee Stock Purchase Plan

The Company has an ESPP that allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the eight-month offering period. Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each offering period, whichever closing sales price is lower.

Postretirement Benefit Obligations

As of December 31, 2006 and 2005, the Company had recorded $19.8 million and $18.6 million, respectively, of unfunded accumulated postretirement benefit obligations, the current and noncurrent portions of which are included in other current liabilities and other liabilities and minority interests, respectively, in the accompanying Consolidated Balance Sheets. These obligations are comprised of five plans of which four relate to predecessor entities that the Company acquired in prior years. These plans had no assets as of December 31, 2006 or 2005. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

As of December 31, 2006, the accumulated postretirement benefit obligations pertaining to these plans were determined by independent actuaries for four plans representing $15.7 million of unfunded accumulated postretirement benefit obligations and by the Company for one plan representing $4.1 million of unfunded accumulated postretirement benefit obligations. Interest costs at an annual rate of 5.95 percent of the periodic undiscounted accumulated postretirement benefit obligations were employed in the valuations of the benefit obligations. Certain of the aforementioned plans provide for medical and dental cost subsidies for plan participants. Annual medical cost escalation trends of 10 percent in 2007, declining to five percent in 2012 and thereafter, and annual dental cost escalation trends of seven percent in 2007, declining to five percent in 2011 and thereafter, were employed to estimate the accumulated postretirement benefit obligations associated with the medical and dental cost subsidies.

The following table reconciles changes in the Company's unfunded accumulated postretirement benefit obligations during the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Beginning accumulated postretirement benefit obligations	$ 18,576	$ 15,534	$ 15,556
Net benefit payments	(1,234)	(1,393)	(1,497)
Service costs	816	324	258
Net actuarial losses (gains)	642	3,211	(32)
Accretion of interest	1,037	900	909
Fair value of Evergreen obligations assumed	—	—	340
Ending accumulated postretirement benefit obligations	$ 19,837	$ 18,576	$ 15,534

Estimated benefit payments and service/interest costs associated with the plans for the year ending December 31, 2007 are $1.5 million and $2.2 million, respectively.

As discussed above in Note B, the Company has adopted the provisions of SFAS 158 effective on December 31, 2006. The Company previously recognized the funded status of its defined benefit postretirement plans and currently recognizes periodic changes in its defined benefit postretirement plans as components of service costs in the period of change as allowed by SFAS 158. Consequently, the adoption of SFAS 158 did not have a material impact on the Company's liquidity, financial position or future results of operations for the year ended December 31, 2006.

NOTE I. Commitments and Contingencies

Severance agreements. The Company has entered into severance and change in control agreements with its officers, subsidiary company officers and certain key employees. The current annual salaries for the parent company officers, the subsidiary company officers and key employees covered under such agreements total $35.4 million.

Indemnifications. The Company has indemnified its directors and certain of its officers, employees and agents with respect to claims and damages arising from acts or omissions taken in such capacity, as well as with respect to certain litigation.

Legal actions. The Company is party to the legal actions that are described below. The Company is also party to other proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company will continue to evaluate its litigation matters on a quarter-by-quarter basis and will adjust its litigation reserves as appropriate to reflect its assessment of the then current status of litigation.

Alford. The Company is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of the Company's gathering systems connected to the Company's Satanta gas plant. The plaintiffs in the case assert that they were improperly charged expenses (primarily field compression), which plaintiffs allege are a "cost of production," and for which the plaintiffs claim they, as royalty owners, are not responsible. Plaintiffs also claim that they are entitled to 50 percent of the value of the helium extracted at the Company's Satanta gas plant.

During the third quarter of 2006, the Company reached an agreement to settle the claims made in the lawsuit. Under the terms of the agreement, the Company agreed to make cash payments to settle the plaintiffs' claims with respect to production occurring on and before December 31, 2005. The Company's portion of the cash payments is expected to be $32.7 million, of which approximately $17.0 million was paid during the third quarter of 2006 and the remaining approximately $15.7 million will be paid in the third quarter of 2007. The Company also agreed to adjust the manner in which royalty payments to the class members will be calculated for production occurring on and after January 1, 2006, which change is not expected to have a material effect on the Company's liquidity, financial position or future results of operations.

Final approval was received from the Court on February 9, 2007, and the settlement is expected to be final within 60 days of final approval assuming no appeals are filed. If no appeals are made or if any appeals made are resolved, it is expected that the settlement will be final in the second quarter of 2007.

MOSH Holding. On April 11, 2005, the Company and its principal United States subsidiary, Pioneer Natural Resources USA, Inc., were named as defendants in *MOSH Holding, L.P. v Pioneer Natural Resources Company; Pioneer Natural Resources USA, Inc.; Woodside Energy (USA) Inc.; and JPMorgan Chase Bank, NA, as Trustee of the Mesa Offshore Trust*, which is before the Judicial District Court of Harris County, Texas (334th Judicial District). On December 8, 2006, Dagger-Spine Hedgehog Corporation (“Dagger-Spine”) filed a Petition In Intervention in the lawsuit to assert the same claims as MOSH Holding, L.P. ("MHLP"). MHLP and Dagger-Spine (collectively, “Plaintiffs”) are unitholders in the Trust, which was created in 1982 as the sole limited partner in a partnership that holds an overriding royalty interest in certain oil and gas leases offshore Louisiana and Texas. The Company owns the managing general partner interest in the partnership. Plaintiffs allege that the Company, together with Woodside Energy (USA) Inc. ("Woodside"), concealed the value of the royalty interest and worked to terminate the Mesa Offshore Trust prematurely and to capture for itself and Woodside profits that belong to the Mesa Offshore Trust ("MOT"). Plaintiffs also allege breaches of fiduciary duty, misapplication of trust property, common law fraud, gross negligence, and breach of the conveyance agreement for the overriding royalty interest. The relief sought by the plaintiffs includes monetary and punitive damages and certain equitable relief, including an accounting of expenses, a setting aside of certain farmouts, and a temporary and permanent injunction.

The Trustee and the Company have reached a conditional settlement of all claims in the lawsuit that MOT has or might have against the Company. Plaintiffs are not signatories to the settlement and they, or other unitholders of MOT, may comment on or object to the settlement. The settlement is subject to certain conditions and is not final until approved by the court and any appeals are resolved. The court has set the settlement review hearing for May 21, 2007.

Dorchester Refining Company Site. A subsidiary of the Company has been notified by a letter from the Texas Commission on Environmental Quality ("TCEQ") dated August 24, 2005 that the TCEQ considers the subsidiary to be a potentially responsible party with respect to the Dorchester Refining Company State Superfund Site located in Mount Pleasant, Texas. In connection with the acquisition of oil and gas assets in 1991, the Company acquired a group of companies, one of which was an entity that had owned a refinery located at the Mount Pleasant site from 1977 until 1984. According to the TCEQ, this refinery was responsible for releases of hazardous substances into the environment. Pursuant to applicable Texas law, the Company's subsidiary, which does not own any material assets or conduct any material operations, may be subject to strict, joint and several liability for the costs of conducting a study to evaluate potential remedial options and for the costs of performing any remediation ultimately required by the TCEQ. The Company does not know the nature and extent of the alleged contamination, the potential costs of remediation or the portion, if any, of such costs that may be allocable to the Company's subsidiary; however, the Company has noted that there appear to be other operators or owners who may share responsibility for these costs and does not expect that any such additional liability will have a material adverse effect on its consolidated financial position as a whole or on its liquidity, financial position or future annual results of operations.

Environmental Protection Agency Investigation. On November 4, 2005, the Company learned from the U.S. Environmental Protection Agency that the agency was conducting a criminal investigation into a 2003 spill that occurred at a Company-operated drilling rig located on an ice island offshore Harrison Bay, Alaska. The investigation is being conducted in conjunction with the U.S. Attorney's Office for the District of Alaska. The spill was previously investigated by the Alaska Department of Environmental Conservation ("ADEC") and, following completion of a clean up, the ADEC issued a letter stating its determination that, at that time, the site did not pose a threat to human health, safety or welfare, or the environment. The Company is fully cooperating with the government's investigation.

Argentine obligations. The Company has provided the purchaser of its Argentine assets certain indemnifications and remains responsible for certain contingent liabilities, subject to defined limitations. The Company does not currently believe that these obligations, which primarily pertain to matters of litigation, environmental contingencies, royalty obligations and income taxes, are probable of having a material impact on its liquidity, financial position or future results of operations.

Lease agreements. The Company leases offshore production facilities, drilling rigs, equipment and office facilities under noncancellable operating leases. Rental expenses associated with these operating leases for the years ended December 31, 2006, 2005 and 2004 were approximately $46.8 million, $64.5 million and $51.8 million, respectively, which includes $8.7 million, $26.0 million and $15.4 million, respectively, associated with discontinued operations. Future minimum lease commitments under noncancellable operating leases at December 31, 2006 are as follows (in thousands):

2007	$ 29,065
2008	$ 14,560
2009	$ 13,346
2010	$ 6,720
2011	$ 709
Thereafter	$ —

Drilling commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future. The Company also enters into agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is expended or rig services are provided.

Transportation agreements. Associated with the Evergreen merger, the Company assumed gas transportation commitments for specified volumes of gas per year through 2014. During 2006, the Company expanded these commitments to support production increases, primarily in the Raton gas field. The transportation commitments averaged approximately 190 million cubic feet ("MMcf") of gross gas sales volumes per day during 2006, including associated fuel commitments. These commitments will average approximately 201 MMcf of gross gas volumes per day during 2007, decrease to approximately 198 MMcf of gross gas volumes per day during 2008, and decline thereafter to approximately 69 MMcf of gross gas volumes per day during 2013, before terminating in January 2014.

The Company's Canadian subsidiaries are parties to pipeline transportation service agreements, with aggregate remaining terms of approximately 10 years, whereby they have committed to transport specified volumes of gas each year principally from Canada to a point in Chicago, Illinois. Such gas volumes totaled approximately 86 MMcf of gas per day during 2006 and 78 MMcf of gas per day during 2005 and 2004, and are comprised of a significant portion of the Company's Canadian net gas production, augmented with certain volumes purchased at market prices in Canada. The committed volumes to be transported under the pipeline transportation service agreements are approximately 85 MMcf of gas per day during 2007 and decline to approximately 75 MMcf of gas per day by the end of the commitment term. The net gas marketing gains or losses resulting from purchasing third party gas in Canada and selling it in Chicago are recorded as other income or other expense in the accompanying Consolidated Statements of Operations. Associated with these agreements, the Company recognized $2.0 and $4.1 million of gas marketing gains in other income during the years ended December 31, 2006 and 2005, respectively, and $1.2 million of gas marketing losses in other expense during the year ended December 31, 2004.

Future minimum transportation fees under the Company's gas transportation commitments at December 31, 2006 are as follows (in thousands):

2007	$ 68,630
2008	$ 68,938
2009	$ 68,458
2010	$ 66,749
2011	$ 64,243
Thereafter	$ 170,546

NOTE J. Derivative Financial Instruments

The Company uses financial derivative contracts to manage exposures to commodity price, interest rate and foreign currency fluctuations. The Company generally does not enter into derivative financial instruments for speculative or trading purposes. The Company also may enter physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the financial statements.

All derivatives are recorded on the balance sheet at estimated fair value. Fair value is generally determined based on the difference between the fixed contract price and the underlying market price at the determination date, and/or the value confirmed by the counterparty. Changes in the fair value of effective cash flow hedges are recorded as a component of accumulated other comprehensive income (loss), which is later transferred to earnings when the hedged transaction occurs. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of the hedge derivatives, are recorded in earnings. The ineffective portion is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged.

Fair value hedges. The Company monitors the debt capital markets and interest rate trends to identify opportunities to enter into and terminate interest rate swap contracts with the objective of reducing costs of capital. As of December 31, 2006 and 2005, the Company was not a party to any open fair value hedges.

As of December 31, 2006, the carrying value of the Company's long-term debt in the accompanying Consolidated Balance Sheets included a $3.4 million reduction in the carrying value attributable to net deferred hedge losses on terminated fair value hedges that are being amortized as net increases to interest expense over the original terms of the terminated agreements. The amortization of net deferred hedge losses on terminated interest rate swaps increased the Company's reported interest expense by $14 thousand during the year ended December 31, 2006, as compared to deferred gains amortization, which reduced the Company's reported interest expense by $4.1 million and $19.2 million during the years ended December 31, 2005 and 2004, respectively.

The following table sets forth, as of December 31, 2006, the scheduled amortization of net deferred hedge losses on terminated interest rate hedges (including terminated fair value and cash flow hedges) that will be recognized as increases to the Company's future interest expense:

	Net Deferred Interest Rate Hedge Losses		
	Fair Value	**Cash Flow**	**Total**
		(in thousands)	
2007	$ 231	$ 94	$ 325
2008	$ 257	$ 114	$ 371
2009	$ 281	$ 135	$ 416
2010	$ 307	$ 159	$ 466
2011	$ 337	$ 184	$ 521
Thereafter	$ 1,978	$ 1,032	$ 3,010

Cash flow hedges. The Company utilizes commodity swap and collar contracts to (i) reduce the effect of price volatility on the commodities the Company produces and sells, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. As of December 31, 2006, all of the Company's open commodity hedges are designated as hedges of Canadian and United States forecasted sales. The Company also, from time to time, utilizes interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness and forward currency exchange agreements to reduce the effect of U.S. dollar to Canadian dollar exchange rate volatility.

Oil prices. All material physical sales contracts governing the Company's oil production have been tied directly or indirectly to the New York Mercantile Exchange ("NYMEX") prices. As of December 31, 2006, all of the Company's oil hedges were designated as hedges of United States forecasted sales. The following table sets forth the volumes hedged in barrels ("Bbl") underlying the Company's outstanding oil hedge contracts and the weighted average NYMEX prices per Bbl for those contracts as of December 31, 2006:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily oil production hedged (a):					
2007 – Swap Contracts					
Volume (Bbl)	3,689	4,341	5,000	5,000	4,512
Price per Bbl	$ 31.63	$ 31.47	$ 31.35	$ 31.35	$ 31.44
2008 – Swap Contracts					
Volume (Bbl)	6,500	6,500	6,500	6,500	6,500
Price per Bbl	$ 31.19	$ 31.19	$ 31.19	$ 31.19	$ 31.19

(a) Subsequent to December 31, 2006, the Company reduced its oil hedge positions by terminating the following oil swap contracts: (i) 4,342 Bbls per day of 2007 swap contracts with a fixed price of $31.47 per Bbl; (ii) 2,500 Bbls per day of 2008 swap contracts with a fixed price of $29.90 per Bbl.

The Company reports average oil prices per Bbl including the effects of oil quality adjustments, amortization of deferred volumetric production payment ("VPP") revenue and the net effect of oil hedges. The following table sets forth (i) the Company's oil prices from continuing operations, both reported (including hedge results and amortization of deferred VPP revenue) and realized (excluding hedge results and amortization of deferred VPP revenue), (ii) amortization of deferred VPP revenue to oil revenue from continuing operations and (iii) the net effect of settlements of oil price hedges on oil revenue from continuing operations for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Average price reported per Bbl	$ 65.51	$ 38.70	$ 32.56
Average price realized per Bbl	$ 63.45	$ 53.71	$ 39.06
VPP increase to oil revenue (in millions)	$ 116.1	$ —	$ —
Reduction to oil revenue from hedging activity (in millions) (a)	$ 97.6	$ 176.6	$ 80.0

(a) Excludes hedge losses of $12.3 million, $52.0 million and $27.2 million attributable to discontinued operations for the years ended December 31, 2006, 2005 and 2004, respectively.

Natural gas liquids prices. During the years ended December 31, 2006, 2005 and 2004, the Company did not enter into any NGL hedge contracts. There were no outstanding NGL hedge contracts at December 31, 2006.

Gas prices. The Company employs a policy of hedging a portion of its gas production based on the index price upon which the gas is actually sold in order to mitigate the basis risk between NYMEX prices and actual index prices, or based on NYMEX prices, if NYMEX prices are highly correlated with the index price. As of December 31, 2006, all of the Company's gas hedges were designated as hedges of United States and Canadian forecasted sales. The following table sets forth the volumes hedged in million British thermal units ("MMBtu") under outstanding gas hedge contracts and the weighted average index prices per MMBtu for those contracts as of December 31, 2006:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily gas production hedged (a):					
2007 – Swap Contracts					
Volume (MMBtu)	89,841	85,000	85,000	85,000	86,194
Price per MMBtu	$ 7.97	$ 8.18	$ 8.18	$ 8.18	$ 8.13
2007 – Collar Contracts					
Volume (MMBtu)	25,000	—	—	—	6,164
Price per MMBtu	$ 9.00-$11.52	$ —	$ —	$ —	$ 9.00-$11.52
2008 – Swap Contracts					
Volume (MMBtu)	15,000	15,000	15,000	15,000	15,000
Price per MMBtu	$ 8.62	$ 8.62	$ 8.62	$ 8.62	$ 8.62

(a) Subsequent to December 31, 2006, the Company entered into additional gas swap contracts of approximately 102,192 MMBtu per day at an average price of $8.13 per MMBtu for the Company's 2007 production.

The Company reports average gas prices per Mcf including the effects of Btu content, gas processing, shrinkage adjustments, amortization of deferred VPP revenue and the net effect of gas hedges. The following table sets forth (i) the Company's gas prices from continuing operations, both reported (including hedge results and amortization of deferred VPP revenue) and realized (excluding hedge results and amortization of deferred VPP revenue), (ii) amortization of deferred VPP revenue to gas revenue from continuing operations and (iii) the net effect of settlements of gas price hedges on gas revenue from continuing operations for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Average price reported per Mcf	$ 6.23	$ 7.02	$ 4.96
Average price realized per Mcf	$ 6.04	$ 7.31	$ 5.45
VPP increase to gas revenue (in millions)	$ 74.2	$ 75.8	$ —
Reduction to gas revenue from hedging activity (in millions) (a)	$ 51.4	$ 108.3	$ 41.9

(a) Excludes hedge losses of $3.4 million, $94.6 million and $83.8 million attributable to discontinued operations for the year ended December 31, 2006, 2005 and 2004, respectively.

Interest rate. During April 2006, the Company entered into costless collar contracts and designated the contracts as cash flow hedges of the forecasted interest rate risk associated with the coupon rate on the Company's 6.875% Notes, which were issued on May 1, 2006. The Company terminated these costless collar contracts for a gain of $1.3 million, which was recorded in AOCI - Hedging. The Company did not realize any ineffectiveness in connection with the costless collar contracts during 2006. See Note F for information regarding the 6.875% Notes.

Hedge ineffectiveness. The Company recognized ineffectiveness amounts related to (i) hedged volumes that exceeded revised forecasts of production volumes due to delays in the start up of production in certain fields and (ii) reduced correlations between the indexes of the financial hedge derivatives and the indexes of the hedged forecasted production for certain fields. Ineffectiveness can be associated with closed contracts (i.e. realized) or can be associated with open positions (i.e. unrealized). The following table sets forth the hedge ineffectiveness attributable to continuing operations recognized in the Consolidated Statements of Operations for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in millions)	
Interest and other income	$ 13.8	$ —	$ —
Other expense	11.6	(44.2)	(4.2)
Total ineffectiveness (a)	$ 25.4	$ (44.2)	$ (4.2)

(a) Hedge ineffectiveness attributable to discontinued operations was $8.2 million and $171 thousand during 2005 and 2004, respectively.

AOCI - Hedging. As of December 31, 2006 and 2005, AOCI - Hedging represented net deferred losses of $167.2 and $506.6 million, respectively. The AOCI - Hedging balance as of December 31, 2006 was comprised of $71.0 million of net deferred losses on the effective portions of open cash flow hedges, $193.7 million of net deferred losses on terminated cash flow hedges (including $1.7 million of net deferred losses on terminated cash flow interest rate hedges) and $97.5 million of associated net deferred tax benefits. The AOCI - Hedging balance as of December 31, 2005 was comprised of $767.8 million of net deferred losses on the effective portions of open cash flow hedges, $30.0 million of net deferred losses on terminated cash flow hedges (including $3.2 million of net deferred losses on terminated cash flow interest rate hedges) and $291.2 million of associated net deferred tax benefits. The decrease in AOCI - Hedging during the year ended December 31, 2006 was primarily attributable to the reclassification of net deferred hedge losses to net income as derivatives matured and, to a lesser extent, decreases in future commodity prices relative to the commodity prices stipulated in the hedge contracts. The net deferred losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. The net deferred losses on terminated cash flow hedges are fixed.

During the year ending December 31, 2007, based on current estimates of future commodity prices, the Company expects to reclassify $5.3 million of net deferred gains associated with open commodity hedges and $106.3 million of net deferred losses on terminated commodity hedges from AOCI - Hedging to oil and gas revenues. The Company also expects to reclassify approximately $38.7 million of net deferred income tax benefits associated with commodity hedges during the year ending December 31, 2007 from AOCI - Hedging to income tax benefit.

Terminated commodity hedges. At times, the Company terminates open commodity hedge positions when the underlying commodity prices reach a point that the Company believes will be the high or low price of the commodity prior to the scheduled settlement of the open commodity position. This allows the Company to maximize gains or minimize losses associated with the open hedge positions. At the time of termination of the hedges, the amounts recorded in AOCI - Hedging are maintained and amortized to earnings over the periods the production was scheduled to occur.

The following table sets forth, as of December 31, 2006, the scheduled amortization of net deferred losses on terminated commodity hedges that will be recognized as decreases to the Company's future oil and gas revenues:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(in thousands)		
2007 net deferred hedge losses	$ 29,619	$ 27,609	$ 25,153	$ 23,905	$ 106,286
2008 net deferred hedge losses	$ 20,285	$ 17,541	$ 17,402	$ 17,718	72,946
2009 net deferred hedge losses	$ 2,330	$ 232	$ 230	$ 822	3,614
2010 net deferred hedge losses	$ 667	$ 620	$ 578	$ 539	2,404
2011 net deferred hedge losses	$ 873	$ 889	$ 902	$ 907	3,571
2012 net deferred hedge losses	$ 810	$ 791	$ 783	$ 773	3,157
					$ 191,978

Non-hedge derivatives. During January and April 2005, the Company entered into non-hedge interest rate swaps. The Company terminated the interest rate swaps during January and April 2005 for an aggregate net loss of $1.5 million, which amount is included in other expense in the Company's accompanying Consolidated Statement of Operations for 2005.

NOTE K. Major Customers and Derivative Counterparties

Sales to major customers. The Company's share of oil and gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company records allowances for doubtful accounts based on the agings of accounts receivable and the general economic condition of its customers and, depending on facts and circumstances, may require customers to provide collateral or otherwise secure their accounts. The Company is of the opinion that the loss of any one purchaser would not have an adverse effect on the ability of the Company to sell its oil and gas production.

The following United States customers individually accounted for ten percent or more of the consolidated oil, NGL and gas revenues, including the revenues from discontinued operations and the results of commodity hedges, in at least one of the years, during the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
Oneok Resources	12%	6%	3%
Plains Marketing LP	12%	7%	4%
Occidental Energy Marketing, Inc.	11%	9%	6%
Williams Power Company, Inc.	4%	9%	14%

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures. As of December 31, 2006, the Company had no derivative counterparties with significant credit risks.

NOTE L. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes the Company's asset retirement obligation transactions during the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Beginning asset retirement obligations	$ 157,035	$ 120,879	$ 105,036
New wells placed on production and changes in estimates (a)	122,685	57,404	4,591
Liabilities assumed in acquisitions	981	3,183	10,488
Disposition of wells	(44,042)	(23,101)	—
Liabilities settled	(16,219)	(9,508)	(8,562)
Accretion of discount on continuing operations	4,826	4,209	4,130
Accretion of discount on discontinued operations	804	3,668	4,080
Currency translation	(157)	301	1,116
Ending asset retirement obligations	$ 225,913	$ 157,035	$ 120,879

(a) Includes, for the years ended December 31, 2006 and 2005, respectively, a $75.0 million and a $39.8 million increase in the abandonment estimate of the East Cameron facilities that were destroyed by Hurricane Rita, which is reflected in hurricane activity, net in the Consolidated Statements of Operations.

The Company records the current and noncurrent portions of asset retirement obligations in other current liabilities and other liabilities and minority interests, respectively, in the accompanying Consolidated Balance Sheets.

NOTE M. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Business interruption insurance claim (see Note U)	$ 7,647	$ 14,200	$ —
Minority interest in subsidiary net loss (see Note B)	4,892	5,206	—
Canadian Alliance marketing gain (see Note I)	2,021	4,127	—
Interest income	15,366	2,177	328
Sales and other tax refunds	645	1,792	—
Credit card rebate	837	835	—
Seismic data sales	620	723	172
Deferred compensation plan income	879	500	202
Foreign currency remeasurement and exchange gains (a)	855	236	100
Derivative ineffectiveness (see Note J)	13,805	—	—
Exploration incentive tax credits	5,570	—	—
Other income	5,586	1,735	1,355
Total interest and other income	$ 58,723	$ 31,531	$ 2,157

(a) The Company's operations in Argentina, Canada and Africa periodically recognize monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.

NOTE N. Asset Divestitures

During the years ended December 31, 2006, 2005 and 2004, the Company completed asset divestitures for net proceeds of $1.8 billion, $1.2 billion and $1.7 million, respectively. Associated therewith, the Company recorded gains (losses) on disposition of assets in continuing operations of $(7.9) million, $59.8 million and $39 thousand during the years ended December 31, 2006, 2005 and 2004, respectively, and gains of $733.3 million and $166.1 million in discontinued operations in 2006 and 2005, respectively. The following represent the significant divestitures:

Deepwater Gulf of Mexico and Argentine divestitures. During 2006, the Company sold its interests in certain oil and gas properties in the deepwater Gulf of Mexico for net proceeds of $1.2 billion, resulting in a gain of $726.2 million and its Argentine assets for net proceeds of $669.6 million, resulting in a gain of $10.9 million. Pursuant to SFAS 144, the gain and the results of operations from these assets have been reclassified to discontinued operations. See Note V for additional information.

Volumetric production payments. During 2005, the Company sold three VPPs for proceeds of $892.6 million. No gain or loss was recognized. See Note T for additional information.

Canadian and Gulf of Mexico Shelf divestitures. During 2005, the Company sold its interests in the Martin Creek, Conroy Black and Lookout Butte areas in Canada for net proceeds of $197.2 million, resulting in a gain of $138.3 million and certain assets on the Gulf of Mexico shelf for net proceeds of $59.2 million, resulting in a gain of $27.9 million. Pursuant to SFAS 144, the gain and the results of operations from these assets have been reclassified to discontinued operations. See Note V for additional information.

East Texas divestiture. During the year ended December 31, 2005, the Company sold its interests in certain East Texas properties for $25.3 million of net cash proceeds with no corresponding gain or loss recognized.

Gabon divestiture. In October 2005, the Company closed the sale of the shares in a Gabonese subsidiary that owns the interest in the Olowi block for $47.9 million of net proceeds. A gain was recognized during the fourth quarter of 2005 of $47.5 million with no associated income tax effect either in Gabon or the United States. In addition, Pioneer retains the potential, under certain circumstances, to receive additional payments for production from deeper reservoirs discovered on the block.

NOTE O. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Derivative ineffectiveness (see Note J)	$ (11,566)	$ 44,246	$ 4,168
Loss on early extinguishment of debt (see Note F)	8,076	25,975	—
Contingency accrual adjustments (see Note I)	10,279	9,756	10,866
Foreign currency remeasurement and exchange losses (a)	580	3,644	1,870
Noncompete agreement amortization	1,670	3,914	798
Minority interest in subsidiaries' net income (see Note B)	2,629	3,482	896
Postretirement obligation revaluation	642	3,211	—
Bad debt expense	4,733	452	3,674
Debt exchange offer costs (see Note F)	—	—	2,248
Canadian Alliance marketing losses (see Note I)	—	—	1,218
Non-hedge derivative losses	6,517	3,860	—
Other charges	12,720	897	2,660
Total other expense	$ 36,280	$ 99,437	$ 28,398

(a) The Company's operations in Argentina, Canada and Africa periodically recognize monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.

NOTE P. Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, "Accounting for Income Taxes" ("SFAS 109"). The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state, local and foreign taxing authorities. Current and estimated tax payments of $153.2 million, $41.4 million and $19.2 million were made during the years ended December 31, 2006, 2005 and 2004, respectively.

SFAS 109 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs") and other deferred tax attributes in the United States, state, local and foreign tax jurisdictions will be utilized prior to their expiration. As of December 31, 2006 and 2005, the Company's valuation allowances related to foreign and domestic tax jurisdictions were $94.7 million and $95.8 million, respectively.

The Company's effective tax rate on continuing operations of 44.2 percent and 44.5 percent for the years ended December 31, 2006 and 2005, respectively, differs from the combined United States federal and state statutory rate of approximately 36.5 percent primarily due to:

- foreign tax rates,
- adjustments to the deferred tax liability for changes in enacted tax laws and rates, as discussed below,
- statutes in foreign jurisdictions that differ from those in the United States,

- recognition of $8.4 million of deferred tax benefit, during 2006, as a result of conversion of senior convertible notes prior to the Company's repayment of the debt principal (see Note F),
- recognition of $7.2 million of taxes during 2005 associated with the repatriation of foreign earnings pursuant to the American Jobs Creation Act of 2004 ("AJCA") and
- expenses for unsuccessful well costs and associated acreage costs in foreign locations where the Company does not expect to receive income tax benefits.

During May 2006, the State of Texas enacted legislation that changed the existing Texas franchise tax from a tax based on net income or taxable capital to an income tax based on a defined calculation of gross margin (the "Texas margin tax"). Also, during 2006, the Canadian federal and provincial governments enacted tax rate reductions that will be phased in over several years. SFAS 109 requires that deferred tax balances be adjusted to reflect tax rate changes during the periods in which the tax rate changes are enacted. The adjustment due to the enactment of the Texas margin tax and the Canadian tax rate changes resulted in a $13.5 million United States tax expense and a $10.2 million Canadian tax benefit during the year ended December 31, 2006, respectively.

In October 2004, the AJCA was signed into law. The AJCA includes a deduction of 85 percent of qualified foreign earnings that are repatriated, as defined in the AJCA. During 2005, the Company determined that it was advantageous to apply the provisions of the AJCA to qualified foreign earnings that could be repatriated. The Company formalized repatriation plans in 2005 and repatriated $322.5 million from Canada, South Africa and Tunisia. Approximately $177 million of the repatriated funds qualified for the dividend exclusion. The Company is obligated by the provisions of the AJCA to invest the qualifying dividends in the United States within a reasonable period of time.

Included in the Company's income tax provision from continuing operations for the year ended December 31, 2005 is the reversal of a $26.9 million tax benefit recorded in 2004 as a result of the cancellation of the development of the Olowi block and the Company's decision to exit Gabon. Reversal of the tax benefit was the result of signing an agreement in June 2005 to sell the Company's shares in the subsidiary that owns the interest in the Olowi block to an unaffiliated buyer, which made it more likely than not that the Company would not realize the originally recorded tax benefit. The Company completed the sale of the Gabonese subsidiary during 2005.

The Company's income tax provision (benefit) and amounts separately allocated were attributable to the following items for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Income from continuing operations	$ 136,666	$ 155,832	$ 63,079
Income from discontinued operations	299,856	209,013	103,280
Changes in goodwill – tax benefits related to stock-based compensation	(1,742)	(7,255)	(8,955)
Changes in stockholders' equity:			
Net deferred hedge gains (losses)	193,719	(166,572)	(73,340)
Tax benefits related to stock-based compensation	(4,247)	(18,752)	(6,612)
Translation adjustment	8,421	3,685	(314)
	$ 632,673	$ 175,951	$ 77,138

The Company's income tax provision (benefit) attributable to income from continuing operations consisted of the following for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
Current:			
U.S. federal	$ (54,004)	$ 13,104	$ 2,500
U.S. state and local	(52)	(254)	602
Foreign	35,811	37,995	14,463
	(18,245)	50,845	17,565
Deferred:			
U.S. federal	126,223	90,944	45,479
U.S. state and local	18,438	3,036	1,097
Foreign	10,250	11,007	(1,062)
	154,911	104,987	45,514
	$ 136,666	$ 155,832	$ 63,079

Income from continuing operations before income taxes consists of the following for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(in thousands)		
U.S. federal	$ 235,049	$ 194,993	$ 210,786
Foreign	73,939	155,473	(13,275)
	$ 308,988	$ 350,466	$ 197,511

Reconciliations of the United States federal statutory tax rate to the Company's effective tax rate for income from continuing operations are as follows for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
	(in percentages)		
U.S. federal statutory tax rate	35.0	35.0	35.0
State income taxes (net of federal benefit)	1.7	1.1	1.2
U.S. valuation allowance changes	0.3	0.2	—
Foreign valuation allowances	8.8	0.3	7.8
Rate differential on foreign operations	0.5	2.6	14.3
Change in statutory rates	1.0	0.1	—
Gabon investment deduction	—	7.4	(13.1)
Gabon tax free book gain	—	(4.7)	—
Repatriation of foreign earnings	—	2.0	—
Conversion of senior convertible notes	(2.7)	—	—
Other	(0.4)	0.5	(13.3)
Consolidated effective tax rate	44.2	44.5	31.9

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows as of December 31, 2006 and 2005:

	December 31, 2006	December 31, 2005
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 102,251	$ 191,314
Alternative minimum tax credit carryforwards	—	10,725
Net deferred hedge losses	97,717	291,216
Asset retirement obligations	76,509	54,338
Other	99,330	95,073
Total deferred tax assets	375,807	642,666
Valuation allowances	(94,745)	(95,750)
Net deferred tax assets	281,062	546,916
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	1,232,025	1,053,989
Other	138,272	101,378
Total deferred tax liabilities	1,370,297	1,155,367
Net deferred tax liability	$ (1,089,235)	$ (608,451)

At December 31, 2006, the Company had NOLs in the United States, Canada, South Africa and other African countries for income tax purposes as set forth below, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, the Company has alternative minimum tax NOLs ("AMT NOLs") in the United States which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

Expiration Date	U.S. NOL	U.S. AMT NOL	Canada NOL	South Africa NOL	Other African NOLs (a)
			(in thousands)		
2009	$ 29,999	$ 32,003	$ —	$ —	$ —
2010	49,858	47,854	—	—	—
2020	5,588	5,055	—	—	—
2021	53	—	—	—	—
2026	—	—	6,269	—	—
Indefinite	—	—	—	49,247	118,190
	$ 85,498	$ 84,912	$ 6,269	$ 49,247	$ 118,190

(a) The Company believes that it is more likely than not that these other African NOLs will not offset future taxable income and has provided a valuation allowance against these deferred tax assets.

The remaining $85 million of the U.S. NOLs and AMT NOLs are subject to Section 382 of the Internal Revenue Code and will become available to offset future regular or alternative minimum taxable income over the next four years. During the years ended December 31, 2006, 2005 and 2004, the Company utilized $409.8 million, $311.6 million and $151.1 million of NOLs, respectively.

The Company's income tax provision (benefit) attributable to income from discontinued operations consisted of the following for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Current:			
U.S. federal	$ 145,622	$ 2,437	$ —
U.S. state and local	1,421	104	—
Foreign	2,138	4,297	7,723
	149,181	6,838	7,723
Deferred:			
U.S. federal	144,380	153,075	93,243
U.S. state and local	6,449	6,560	3,996
Foreign	(154)	42,540	(1,682)
	150,675	202,175	95,557
	$ 299,856	$ 209,013	$ 103,280

NOTE Q. Income Per Share From Continuing Operations

Basic income per share from continuing operations is computed by dividing income from continuing operations by the weighted average number of common shares outstanding for the period. The computation of diluted income per share from continuing operations reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income from continuing operations were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company.

The following table is a reconciliation of the basic income from continuing operations to diluted income from continuing operations for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Basic income from continuing operations	$ 172,322	$ 194,634	$ 134,432
Interest expense on convertible notes, net of tax	1,903	3,207	802
Diluted income from continuing operations	$ 174,225	$ 197,841	$ 135,234

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Weighted average common shares outstanding (a):			
Basic	124,359	137,110	125,156
Dilutive common stock options (b)	747	1,136	1,218
Restricted stock awards	989	844	529
Convertible notes dilution (c)	1,513	2,327	585
Diluted	127,608	141,417	127,488

(a) During 2005, the Board approved a share repurchase program authorizing the purchase of up to $1 billion of the Company's common stock, $640.7 million of which was completed in 2005 and $345.3 million of which was completed in 2006.

(b) Common stock options to purchase 30,712 shares of common stock were outstanding but not included in the computations of diluted income per share from continuing operations for 2004 because the exercise prices of the options were greater than the average market price of the common shares and would be anti-dilutive to the computation.

(c) During 2006, holders of all of the $100 million of 4 3/4% Senior Convertible Notes exercised their conversion rights.

NOTE R. Geographic Operating Segment Information

The Company has operations in only one industry segment, that being the oil and gas exploration and production industry; however, the Company is organizationally structured along geographic operating segments or regions. The Company has reportable continuing operations in the United States, Canada, South Africa, Tunisia and Other. Other is primarily comprised of operations in Equatorial Guinea, Gabon and Nigeria.

During 2006, the Company sold certain oil and gas properties in the deepwater Gulf of Mexico and all of its Argentine assets, which had carrying values of $430.6 million and $658.7 million, respectively, on their dates of sale. During 2005, the Company sold certain Canadian and United States oil and gas properties having carrying values of $58.9 million and $31.4 million, respectively, on their dates of sale. The results of operations of those properties have been reclassified as discontinued operations in accordance with SFAS 144 and, aside from costs incurred for oil and gas activities, are excluded from the geographic operating segment information provided below. See Note V for information regarding the Company's discontinued operations.

The following tables provide the Company's geographic operating segment data required by SFAS No. 131, "Disclosure about Segments of an Enterprise and Related Information", as well as results of operations of oil and gas producing activities required by SFAS No. 69, "Disclosures about Oil and Gas Producing Activities" as of and for the years ended December 31, 2006, 2005 and 2004. Geographic operating segment income tax benefits (provisions) have been determined based on statutory rates existing in the various tax jurisdictions where the Company has oil and gas producing activities. The "Headquarters" table column includes income and expenses that are not routinely included in the earnings measures internally reported to management on a geographic operating segment basis.

December 31, 2006, 2005 and 2004

	United States	Canada	South Africa	Tunisia	Other	Headquarters	Consolidated Total
				(in thousands)			
Year ended December 31, 2006:							
Revenues and other income:							
Oil and gas	$ 1,302,029	$ 123,109	$ 99,309	$ 57,602	$ —	$ —	$ 1,582,049
Interest and other	—	—	—	—	—	58,723	58,723
Gain (loss) on disposition of assets, net	(451)	77	—	—	—	(7,517)	(7,891)
	1,301,578	123,186	99,309	57,602	—	51,206	1,632,881
Costs and expenses:							
Oil and gas production	324,048	49,192	21,795	3,222	—	—	398,257
Depletion, depreciation and amortization	276,921	44,990	9,455	4,007	—	24,150	359,523
Exploration and abandonments	172,860	13,948	7,516	14,616	55,205	—	264,145
General and administrative	—	—	—	—	—	121,830	121,830
Accretion of discount on asset retirement obligations	—	—	—	—	—	4,826	4,826
Interest	—	—	—	—	—	107,032	107,032
Hurricane activity, net	32,000	—	—	—	—	—	32,000
Other	—	—	—	—	—	36,280	36,280
	805,829	108,130	38,766	21,845	55,205	294,118	1,323,893
Income (loss) from continuing operations before income taxes	495,749	15,056	60,543	35,757	(55,205)	(242,912)	308,988
Income tax benefit (provision)	(180,948)	(4,920)	(17,557)	(22,450)	—	89,209	(136,666)
Income (loss) from continuing operations	$ 314,801	$ 10,136	$ 42,986	$ 13,307	$ (55,205)	$ (153,703)	$ 172,322
Costs incurred for oil and gas activities (a)	$ 1,184,280	$ 228,664	$ 131,763	$ 46,149	$ 46,756	$ 35,767	$ 1,673,379
Year ended December 31, 2005:							
Revenues and other income:							
Oil and gas	$ 1,144,163	$ 114,357	$ 127,470	$ 67,250	$ —	$ —	$ 1,453,240
Interest and other	—	—	—	—	—	31,531	31,531
Gain (loss) on disposition of assets, net	12,114	(221)	—	—	47,532	402	59,827
	1,156,277	114,136	127,470	67,250	47,532	31,933	1,544,598
Costs and expenses:							
Oil and gas production	277,297	36,725	28,354	4,063	—	—	346,439
Depletion, depreciation and amortization	219,045	31,469	24,494	4,758	—	20,178	299,944
Impairment of long-lived assets	—	—	—	—	644	—	644
Exploration and abandonments	97,126	9,545	1,211	10,898	44,543	—	163,323
General and administrative	—	—	—	—	—	114,237	114,237
Accretion of discount on asset retirement obligations	—	—	—	—	—	4,209	4,209
Interest	—	—	—	—	—	126,086	126,086
Hurricane activity, net	39,813	—	—	—	—	—	39,813
Other	—	—	—	—	—	99,437	99,437
	633,281	77,739	54,059	19,719	45,187	364,147	1,194,132
Income (loss) from continuing operations before income taxes	522,996	36,397	73,411	47,531	2,345	(332,214)	350,466
Income tax benefit (provision)	(190,894)	(13,285)	(21,289)	(32,422)	—	102,058	(155,832)
Income (loss) from continuing operations	$ 332,102	$ 23,112	$ 52,122	$ 15,109	$ 2,345	$ (230,156)	$ 194,634
Costs incurred for oil and gas activities (a)	$ 903,390	$ 131,237	$ 18,541	$ 21,317	$ 75,411	$ 129,640	$ 1,279,536

(a) Costs incurred for Headquarters represents Argentine cost incurred prior to divestment.

	United States	Canada	South Africa	Tunisia	Other	Headquarters	Consolidated Total
				(in thousands)			
Year ended December 31, 2004:							
Revenues and other income:							
Oil and gas	$ 799,241	$ 50,447	$ 129,856	$ 33,064	$ —	$ —	$ 1,012,608
Interest and other	—	—	—	—	—	2,157	2,157
Gain (loss) on disposition of assets, net	51	(252)	—	—	—	240	39
	799,292	50,195	129,856	33,064	—	2,397	1,014,804
Costs and expenses:							
Oil and gas production	174,583	18,810	28,478	3,032	—	—	224,903
Depletion, depreciation and amortization	149,282	22,551	44,091	3,744	—	11,930	231,598
Impairment of long-lived assets	—	—	—	—	39,684	—	39,684
Exploration and abandonments	55,010	19,062	530	2,042	36,727	—	113,371
General and administrative	—	—	—	—	—	73,192	73,192
Accretion of discount on asset retirement obligations	—	—	—	—	—	4,130	4,130
Interest	—	—	—	—	—	102,017	102,017
Other	—	—	—	—	—	28,398	28,398
	378,875	60,423	73,099	8,818	76,411	219,667	817,293
Income (loss) from continuing operations before income taxes	420,417	(10,228)	56,757	24,246	(76,411)	(217,270)	197,511
Income tax benefit (provision)	(153,452)	3,861	(17,027)	(12,124)	—	115,663	(63,079)
Income (loss) from continuing operations	$ 266,965	$ (6,367)	$ 39,730	$ 12,122	$ (76,411)	$ (101,607)	$ 134,432
Costs incurred for oil and gas activities (a)	$ 2,876,185	$ 120,626	$ 9,473	$ 17,015	$ 48,418	$ 102,452	$ 3,174,169

(a) Costs incurred for Headquarters represents Argentine cost incurred prior to divestment.

	December 31, 2006	December 31, 2005	December 31, 2004
		(in thousands)	
Total Assets:			
United States	$ 6,395,046	$ 5,899,637	$ 5,460,708
Argentina	2,444	735,191	708,391
Canada	547,012	363,773	316,124
South Africa	176,789	64,071	74,250
Tunisia	72,142	59,125	37,924
Other	41,238	47,288	10,899
Headquarters	120,728	160,149	125,191
Total consolidated assets	$ 7,355,399	$ 7,329,234	$ 6,733,487

NOTE S. Impairment of Oil and Gas Properties

During October 2004, the Company concluded that a $39.7 million charge for impairment was required under SFAS 144 for its Gabonese Olowi field as development of the discovery was canceled. Due to significant increases in projected field development costs, primarily due to increases in steel costs, the project did not offer competitive returns. The Olowi field was the Company's only Gabonese investment. During 2005, the Company recorded an incremental impairment charge of $644 thousand to eliminate the carrying value of the Company's Gabonese Olowi field.

NOTE T. Volumetric Production Payments

During 2005, the Company sold 27.8 MMBOE of proved reserves by means of three VPP agreements for net proceeds of $892.6 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were initially used to reduce outstanding indebtedness. The first VPP sold 58 Bcf of gas volumes over an expected five-year term that began in February 2005. The second VPP sold 10.8 million barrels of oil ("MMBbls") of oil volumes over an expected seven-year term that began in January 2006. The third VPP sold 6.0 Bcf of gas volumes over an expected 32-month term that began in May 2005 and 6.2 MMBbls of oil volumes over an expected five-year term that began in January 2006.

The Company's VPPs represent limited-term overriding royalty interests in oil and gas reserves which: (i) entitle the purchaser to receive production volumes over a period of time from specific lease interests; (ii) are free and clear of all associated future production costs and capital expenditures; (iii) are nonrecourse to the Company (i.e., the purchaser's only recourse is to the assets acquired); (iv) transfer title to the purchaser; and (v) allow the Company to retain the assets after the VPPs volumetric quantities have been delivered.

Under SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," a VPP is considered a sale of proved reserves. As a result, the Company (i) removed the proved reserves associated with the VPPs; (ii) recognized the VPP proceeds as deferred revenue which are being amortized on a unit-of-production basis to oil and gas revenues over the terms of the VPPs; (iii) retained responsibility for 100 percent of the production costs and capital costs related to VPP interests; and (iv) no longer recognizes production associated with the VPP volumes.

The following table provides information about the deferred revenue carrying values of the Company's VPPs:

	Gas	Oil (in thousands)	Total
Deferred revenue at December 31, 2005	$ 249,323	$ 605,515	$ 854,838
Less 2006 amortization	(74,235)	(116,092)	(190,327)
Deferred revenue at December 31, 2006	$ 175,088	$ 489,423	$ 664,511

The above deferred revenue amounts will be recognized in oil and gas revenues in the Consolidated Statements of Operations as noted below, assuming the related VPP production volumes are delivered as scheduled (in thousands):

2007	$ 181,232
2008	158,138
2009	147,906
2010	90,215
2011	44,951
2012	42,069
	$ 664,511

NOTE U. Insurance Claims

Hurricane Ivan. During September 2004, the Company sustained damages as a result of Hurricane Ivan at its Devils Tower and Canyon Express platform facilities in the deepwater Gulf of Mexico. The damages delayed scheduled well completions and interrupted production during the second half of 2004 and during the first half of 2005. The Company maintains business interruption insurance coverage for such circumstances. During 2004 and 2005, the Company filed claims with its insurance providers for its estimated losses associated with Hurricane Ivan.

Based on a settlement agreement between the Company and the insurance providers, the Company's recoverable business interruption loss related to Hurricane Ivan was $67.0 million. The Company recorded $7.6 million and $59.4 million of the claims in 2004 and 2005, respectively, in income from discontinued operations in the accompanying Consolidated Statements of Operations.

Fain Plant. During May 2005, the Company sustained damages as a result of a fire at its Fain gas plant in the West Panhandle field. The damages interrupted production from mid-May through mid-July of 2005. The Company maintained business interruption and physical damage insurance coverage for such circumstances. The Company recognized a total of $17.9 million in business interruption recoveries and $4.4 million in physical damage recoveries associated with the Fain gas plant fire. The Company recognized $14.2 million of the business interruption recoveries in 2005 and the remaining $3.7 million in 2006, which is included in other income in the accompanying Consolidated Statements of Operations.

Hurricanes Katrina and Rita. During August and September 2005, the Company sustained damages as a result of Hurricanes Katrina and Rita at various facilities in the Gulf of Mexico. Other than the East Cameron facility discussed further below, the damages to the facilities were covered by physical damage insurance.

The Company filed a business interruption claim with its insurance provider related to its Devils Tower field resulting from its inability to sell production as a result of damages to third-party facilities. During 2006, the Company settled its business interruption claim with its insurance provider for $18.5 million, which is included in income from discontinued operations in the accompanying Consolidated Statements of Operations.

As a result of Hurricane Rita, the Company's East Cameron facility, located in the Gulf of Mexico shelf, was destroyed and the Company does not plan to rebuild the facility based on the economics of the field. During the fourth quarter of 2006, the Company's application to "reef in-place" a substantial portion of the East Cameron debris was denied. As a result, the Company currently estimates that it will cost approximately $119 million to reclaim and abandon the East Cameron facility. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis and fee proposal prepared by a third-party engineering firm for the majority of the work and an estimate by the Company for the remainder. During 2006 and 2005, the Company recorded additional abandonment obligation charges of $75.0 million and $39.8 million, respectively, which amounts are included in hurricane activity, net in the accompanying Consolidated Statements of Operations. The operations to reclaim and abandon the East Cameron facilities began in January 2007 and the Company expects to incur a substantial portion of the costs in 2007.

The $119 million estimate to reclaim and abandon the East Cameron facilities contains a number of assumptions that could cause the ultimate cost to be higher or lower as there are many uncertainties when working offshore and underwater with damaged equipment and wellbores. The Company currently believes costs could range from $119 million to $175 million; however, at this point no better estimate than any other amount within the range can be determined, thus the Company has recorded the estimated provision of $119 million.

The Company has filed a claim with its insurance providers regarding the loss at East Cameron. Under the Company’s insurance policies, the East Cameron facility had the following coverages: (a) $14 million of scheduled property value for the platform, (b) $4 million of scheduled business interruption insurance after a deductible waiting period, (c) $100 million of well restoration and safety, in total, for all assets per occurrence and (d) $400 million for debris removal coverage for all assets per occurrence.

In December 2005, the Company received the $14 million of scheduled property value for the East Cameron assets and recognized a gain of $9.7 million associated therewith. The Company received the $4 million of business interruption recoveries in 2006, which is reflected in interest and other income in the accompanying Consolidated Statements of Operations. During the fourth quarter of 2006, the Company recorded estimated insurance recoveries of $43 million, which is reflected in other current assets in the accompanying Consolidated Balance Sheet and in hurricane activity, net in the accompanying Consolidated Statements of Operations, related to the estimated costs for the debris removal portion of the claim as the Company believes that it is probable that it will be successful in asserting coverage under the debris removal part of its insurance coverage. At the present, no recoveries have been reflected related to the well restoration and safety coverages as the Company is working to resolve coverage issues regarding coverage under this section of the insurance policies. Overall, the Company ultimately expects a substantial portion of the loss to be covered by insurance.

NOTE V. Discontinued Operations

During 2005 and 2006, the Company sold its interests in the following significant oil and gas assets:

Country	Description of Assets	Date Divested	Net Proceeds	Gain
			(in millions)	
Canada	Martin Creek, Conroy Black and Lookout Butte fields	May 2005	$ 197.2	$ 138.3
United States	Two Gulf of Mexico shelf fields	August 2005	$ 59.2	$ 27.9
United States	Deepwater Gulf of Mexico fields	March 2006	$ 1,156.9 (a)	$ 726.2
Argentina	Argentine assets	April 2006	$ 669.6	$ 10.9

(a) Net proceeds do not reflect the cash payment of $164.3 million for terminated hedges associated with the deepwater Gulf of Mexico assets.

Pursuant to SFAS 144, the Company has reflected the results of operations of the above divestitures as discontinued operations, rather than as a component of continuing operations. The following table represents the components of the Company's discontinued operations for the years ended December 31, 2006, 2005 and 2004:

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Revenues and other income:			
Oil and gas	$ 199,317	$ 806,347	$ 820,055
Interest and other	23,217	65,519	11,918
Gain on disposition of assets (a)	733,259	166,088	—
	955,793	1,037,954	831,973
Costs and expenses:			
Oil and gas production	31,323	116,638	120,601
Depletion, depreciation and amortization (a)	37,327	279,286	343,277
Exploration and abandonments (a)	7,327	63,855	68,318
General and administrative	9,266	10,486	7,336
Accretion of discount on asset retirement obligations (a)	804	3,668	4,080
Interest	460	1,700	1,370
Other	2,021	13,374	5,289
	88,528	489,007	550,271
Income from discontinued operations before income taxes	867,265	548,947	281,702
Income tax provision:			
Current	149,181	6,838	7,723
Deferred (a)	150,675	202,175	95,557
Income from discontinued operations	$ 567,409	$ 339,934	$ 178,422

(a) Represents the significant noncash components of discontinued operations included in the Company's Consolidated Statements of Cash Flows.

PIONEER NATURAL RESOURCES COMPANY

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2006, 2005 and 2004

Capitalized Costs

	December 31, 2006	December 31, 2005
	(in thousands)	
Oil and gas properties:		
Proved	$ 7,967,708	$ 8,499,253
Unproved	210,344	313,881
Capitalized costs for oil and gas properties	8,178,052	8,813,134
Less accumulated depletion, depreciation and amortization	(1,895,408)	(2,577,946)
Net capitalized costs for oil and gas properties	$ 6,282,644	$ 6,235,188

Costs Incurred for Oil and Gas Producing Activities (a)

	Property Acquisition Costs		Exploration Costs	Development Costs	Total Costs Incurred
	Proved	Unproved			
			(in thousands)		
Year Ended December 31, 2006:					
United States	$ 78,318	$ 109,321	$ 296,301	$ 700,340	$ 1,184,280
Argentina	—	2	10,223	25,542	35,767
Canada	—	19,932	103,245	105,487	228,664
South Africa	—	—	288	131,475	131,763
Tunisia	—	5,000	40,813	336	46,149
Other	—	10,584	36,172	—	46,756
Total	$ 78,318	$ 144,839	$ 487,042	$ 963,180	$ 1,673,379
Year Ended December 31, 2005:					
United States	$ 170,827	$ 60,731	$ 217,723	454,109	$ 903,390
Argentina	—	512	36,878	92,250	129,640
Canada	2,593	7,344	43,437	77,863	131,237
South Africa	—	259	755	17,527	18,541
Tunisia	—	—	18,395	2,922	21,317
Other	—	30,664	44,456	291	75,411
Total	$ 173,420	$ 99,510	$ 361,644	$ 644,962	$ 1,279,536
Year Ended December 31, 2004:					
United States	$ 2,220,813	$ 301,856	$ 127,338	$ 226,178	$ 2,876,185
Argentina	—	—	49,745	52,707	102,452
Canada	50,542	20,921	33,406	15,757	120,626
South Africa	—	—	737	8,736	9,473
Tunisia	—	6,558	5,761	4,696	17,015
Other	—	11,680	26,434	10,304	48,418
Total	$ 2,271,355	$ 341,015	$ 243,421	$ 318,378	$ 3,174,169

(a) The costs incurred for oil and gas producing activities includes the following amounts of asset retirement obligations:

	Year Ended December 31, 2006	2005	2004
		(in thousands)	
Proved property acquisition costs	$ 981	$ 3,183	$ 10,488
Exploration costs	3,376	—	—
Development costs	41,111	16,055	4,591
Total	$ 45,468	$ 19,238	$ 15,079

Results of Operations

Information about the Company's results of operations for oil and gas producing activities by geographic operating segment is presented in Note R of the accompanying Notes to Consolidated Financial Statements.

Reserve Quantity Information

The estimates of the Company's proved oil and gas reserves as of December 31, 2006, 2005 and 2004, which are located in the United States, Argentina, Canada, South Africa and Tunisia, were based on evaluations prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. Reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements. The Company reports all reserves held under production sharing arrangements and concessions utilizing the "economic interest" method, which excludes the host country's share of proved reserves. Estimated quantities for production sharing arrangements reported under the "economic interest" method are subject to fluctuations in the prices of oil and gas and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. The reserve estimates as of December 31, 2006, 2005 and 2004 utilized respective oil prices of $60.54, $59.62 and $41.96 per Bbl (reflecting adjustments for oil quality), respective NGL prices of $29.82, $36.34 and $29.12 per Bbl, and respective gas prices of $5.13, $6.36 and $4.76 per Mcf (reflecting adjustments for Btu content, gas processing and shrinkage).

Oil and gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following table provides a rollforward of total proved reserves by geographic area and in total for the years ended December 31, 2006, 2005 and 2004, as well as proved developed reserves by geographic area and in total as of the beginning and end of each respective year. Oil and NGL volumes are expressed in MBbls, gas volumes are expressed in MMcf and total volumes are expressed in thousands of barrels of oil equivalent ("MBOE").

UNAUDITED SUPPLEMENTARY INFORMATION
Years Ended December 31, 2006, 2005 and 2004

	Year Ended December 31,								
	2006			2005			2004		
	Oil & NGLs (MBbls)	Gas (MMcf) (a)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf) (a)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf) (a)	MBOE
Total Proved Reserves:									
UNITED STATES									
Balance, January 1	385,771	2,750,856	844,247	363,257	3,000,335	863,313	362,751	1,553,976	621,747
Revisions of previous estimates	(7,467)	(10,664)	(9,244)	(5,471)	(141,473)	(29,049)	4,671	25,764	8,965
Purchases of minerals-in-place	41,825	52,308	50,543	65,800	83,179	79,663	11,803	1,571,053	273,646
Extensions and discoveries	11,948	136,712	34,733	225	103,616	17,494	1,017	56,690	10,465
Production (b)	(14,091)	(134,445)	(36,499)	(16,311)	(197,391)	(49,210)	(16,974)	(200,598)	(50,407)
Sales of minerals-in-place	(11,261)	(108,806)	(29,395)	(21,729)	(97,410)	(37,964)	(11)	(6,550)	(1,103)
Balance, December 31	406,725	2,685,961	854,385	385,771	2,750,856	844,247	363,257	3,000,335	863,313
ARGENTINA									
Balance, January 1	34,024	404,323	101,411	33,168	560,374	126,564	33,469	549,856	125,112
Revisions of previous estimates	(306)	(2,043)	(646)	2,060	(137,640)	(20,881)	(3,040)	(61,483)	(13,287)
Extensions and discoveries	135	4,576	898	2,334	31,606	7,602	6,428	116,526	25,849
Production (b)	(1,072)	(16,025)	(3,743)	(3,538)	(50,017)	(11,874)	(3,689)	(44,525)	(11,110)
Sales of minerals-in-place	(32,781)	(390,831)	(97,920)	—	—	—	—	—	—
Balance, December 31	—	—	—	34,024	404,323	101,411	33,168	560,374	126,564
CANADA									
Balance, January 1	2,423	130,514	24,175	4,095	119,869	24,073	2,407	93,829	18,045
Revisions of previous estimates	(159)	(7,953)	(1,485)	434	15,887	3,082	710	8,580	2,140
Purchases of minerals-in-place	—	—	—	—	292	49	823	22,127	4,511
Extensions and discoveries	217	66,801	11,351	652	55,130	9,840	541	10,656	2,317
Production (b)	(282)	(15,853)	(2,924)	(311)	(15,665)	(2,922)	(386)	(15,323)	(2,940)
Sales of minerals-in-place	—	—	—	(2,447)	(44,999)	(9,947)	—	—	—
Balance, December 31	2,199	173,509	31,117	2,423	130,514	24,175	4,095	119,869	24,073
SOUTH AFRICA									
Balance, January 1	3,055	60,395	13,121	3,419	—	3,419	5,546	—	5,546
Revisions of previous estimates	1,521	116	1,541	694	—	694	1,302	—	1,302
Extensions and discoveries	—	—	—	1,347	60,395	11,413	—	—	—
Production (b)	(1,506)	—	(1,506)	(2,405)	—	(2,405)	(3,429)	—	(3,429)
Balance, December 31	3,070	60,511	13,156	3,055	60,395	13,121	3,419	—	3,419
TUNISIA									
Balance, January 1	3,769	—	3,769	4,852	—	4,852	2,018	—	2,018
Revisions of previous estimates	1,579	59	1,588	(510)	—	(510)	3,177	—	3,177
Extensions and discoveries	500	8,223	1,870	696	—	696	502	—	502
Production (b)	(871)	(436)	(943)	(1,269)	—	(1,269)	(845)	—	(845)
Balance, December 31	4,977	7,846	6,284	3,769	—	3,769	4,852	—	4,852
GABON									
Balance, January 1	—	—	—	—	—	—	16,590	—	16,590
Revisions of previous estimates	—	—	—	—	—	—	(16,590)	—	(16,590)
Balance, December 31	—	—	—	—	—	—	—	—	—
TOTAL									
Balance, January 1	429,042	3,346,088	986,723	408,791	3,680,578	1,022,221	422,781	2,197,661	789,058
Revisions of previous estimates	(4,832)	(20,485)	(8,246)	(2,793)	(263,226)	(46,664)	(9,770)	(27,139)	(14,293)
Purchases of minerals-in-place	41,825	52,308	50,543	65,800	83,471	79,712	12,626	1,593,180	278,157
Extensions and discoveries	12,800	216,312	48,852	5,254	250,747	47,045	8,488	183,872	39,133
Production (b)	(17,822)	(166,759)	(45,615)	(23,834)	(263,073)	(67,680)	(25,323)	(260,446)	(68,731)
Sales of minerals-in-place	(44,042)	(499,637)	(127,315)	(24,176)	(142,409)	(47,911)	(11)	(6,550)	(1,103)
Balance, December 31	416,971	2,927,827	904,942	429,042	3,346,088	986,723	408,791	3,680,578	1,022,221

(a) The proved gas reserves as of December 31, 2006, 2005 and 2004 include 316,528 MMcf, 306,303 MMcf and 271,667 MMcf, respectively, of gas that will be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.

(b) Production for 2006, 2005 and 2004 includes approximately 17,364 MMcf, 14,452 MMcf and 9,605 MMcf of field fuel, respectively. Also, for 2006, 2005 and 2004, production includes 6,811 MBOE, 28,273 MBOE and 33,136 MBOE of production associated with discontinued operations. See Note V for additional information.

	Year Ended December 31,								
	2006			2005			2004		
	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE	Oil & NGLs (MBbls)	Gas (MMcf)	MBOE
Proved Developed Reserves:									
United States	210,680	1,875,866	523,324	223,749	2,045,275	564,628	209,349	1,202,264	409,727
Argentina	20,844	282,815	67,980	20,565	320,616	74,001	21,149	352,660	79,926
Canada	2,202	99,025	18,706	3,849	107,547	21,773	2,312	86,500	16,728
South Africa	1,708	—	1,708	3,419	—	3,419	5,546	—	5,546
Tunisia	3,769	—	3,769	4,852	—	4,852	1,271	—	1,271
Balance, January 1	239,203	2,257,706	615,487	256,434	2,473,438	668,673	239,627	1,641,424	513,198
United States	211,814	1,805,974	512,809	210,680	1,875,866	523,324	223,749	2,045,275	564,628
Argentina	—	—	—	20,844	282,815	67,980	20,565	320,616	74,001
Canada	2,053	117,672	21,665	2,202	99,025	18,706	3,849	107,547	21,773
South Africa	1,822	—	1,822	1,708	—	1,708	3,419	—	3,419
Tunisia	4,977	7,846	6,285	3,769	—	3,769	4,852	—	4,852
Balance, December 31	220,666	1,931,492	542,581	239,203	2,257,706	615,487	256,434	2,473,438	668,673

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of ten percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity hedging contracts. Utilizing December 31, 2006 commodity prices held constant over each hedge contract's term, the net present value of the Company's hedge obligations, less associated estimated income taxes and discounted at ten percent, was a liability of approximately $82 million at December 31, 2006.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and gas properties. Estimates of fair value should also consider probable reserves, anticipated future oil and gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

The following tables provide the standardized measure of discounted future cash flows by geographic area and in total for the years ended December 31, 2006, 2005 and 2004, as well as a roll forward in total for each respective year:

	December 31, 2006	December 31, 2005	December 31, 2004
		(in thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 32,162,975	$ 37,171,750	$ 28,373,520
Future production costs	(10,605,170)	(10,911,204)	(8,232,530)
Future development costs	(3,746,920)	(2,757,072)	(1,829,937)
Future income tax expense	(5,695,788)	(7,552,644)	(5,612,935)
	12,115,097	15,950,830	12,698,118
10% annual discount factor	(7,925,926)	(9,872,066)	(7,116,815)
Standardized measure of discounted future cash flows	$ 4,189,171	$ 6,078,764	$ 5,581,303
ARGENTINA			
Oil and gas producing activities:			
Future cash inflows	$ —	$ 2,256,468	$ 1,747,737
Future production costs	—	(366,362)	(289,742)
Future development costs	—	(353,182)	(234,309)
Future income tax expense	—	(282,661)	(221,733)
	—	1,254,263	1,001,953
10% annual discount factor	—	(446,366)	(354,661)
Standardized measure of discounted future cash flows	$ —	$ 807,897	$ 647,292
CANADA			
Oil and gas producing activities:			
Future cash inflows	$ 1,054,264	$ 1,062,258	$ 889,940
Future production costs	(399,248)	(404,891)	(286,197)
Future development costs	(115,721)	(46,312)	(40,023)
Future income tax expense	(69,693)	(166,333)	(96,431)
	469,602	444,722	467,289
10% annual discount factor	(200,313)	(190,655)	(190,822)
Standardized measure of discounted future cash flows	$ 269,289	$ 254,067	$ 276,467
SOUTH AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 509,081	$ 503,499	$ 140,059
Future production costs	(82,989)	(56,987)	(61,845)
Future development costs	(165,318)	(248,005)	(13,252)
Future income tax expense	(58,870)	(18,510)	—
	201,904	179,997	64,962
10% annual discount factor	(58,182)	(70,453)	(2,150)
Standardized measure of discounted future cash flows	$ 143,722	$ 109,544	$ 62,812
TUNISIA			
Oil and gas producing activities:			
Future cash inflows	$ 329,773	$ 214,982	$ 193,032
Future production costs	(47,116)	(9,164)	(13,536)
Future development costs	(16,265)	(2,700)	(1,245)
Future income tax expense	(148,361)	(121,675)	(81,680)
	118,031	81,443	96,571
10% annual discount factor	(31,224)	(34,818)	(21,370)
Standardized measure of discounted future cash flows	$ 86,807	$ 46,625	$ 75,201
TOTAL			
Oil and gas producing activities:			
Future cash inflows	$ 34,056,093	$ 41,208,957	$ 31,344,288
Future production costs	(11,134,523)	(11,748,608)	(8,883,850)
Future development costs (a)	(4,044,224)	(3,407,271)	(2,118,766)
Future income tax expense	(5,972,712)	(8,141,823)	(6,012,779)
	12,904,634	17,911,255	14,328,893
10% annual discount factor	(8,215,645)	(10,614,358)	(7,685,818)
Standardized measure of discounted future cash flows	$ 4,688,989	$ 7,296,897	$ 6,643,075

(a) Includes $324.1 million, $357.5 million and $258.1 million of undiscounted future asset retirement expenditures estimated as of December 31, 2006, 2005 and 2004, respectively, using current estimates of future abandonment costs. See Note L for corresponding information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2006	2005	2004
		(in thousands)	
Oil and gas sales, net of production costs	$ (1,516,503)	$ (2,227,267)	$ (1,719,990)
Net changes in prices and production costs	(1,921,270)	3,932,683	2,082,706
Extensions and discoveries	413,200	459,251	302,794
Development costs incurred during the period	672,572	446,978	249,890
Sales of minerals-in-place	(1,926,423)	(1,492,864)	(14,222)
Purchases of minerals-in-place	280,475	645,315	2,058,195
Revisions of estimated future development costs	(1,041,343)	(907,229)	(447,828)
Revisions of previous quantity estimates	(38,837)	(595,873)	140,950
Accretion of discount	895,455	908,047	644,238
Changes in production rates, timing and other	486,328	78,880	(167,400)
Change in present value of future net revenues	(3,696,346)	1,247,921	3,129,333
Net change in present value of future income taxes	1,088,438	(594,099)	(1,069,511)
	(2,607,908)	653,822	2,059,822
Balance, beginning of year	7,296,897	6,643,075	4,583,253
Balance, end of year	$ 4,688,989	$ 7,296,897	$ 6,643,075

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2006 and 2005:

	Quarter			
	First	Second	Third	Fourth
	(in thousands, except per share data)			
Year ended December 31, 2006:				
Oil and gas revenues	$ 379,468	$ 407,570	$ 418,106	$ 376,905
Total revenues	$ 396,506	$ 413,908	$ 432,627	$ 389,840
Total costs and expenses	$ 376,756	$ 297,815	$ 312,031	$ 337,291
Net income	$ 543,207	$ 88,039	$ 80,799	$ 27,686
Net income per share:				
Basic	$ 4.28	$ .70	$ .65	$ .23
Diluted	$ 4.28	$ .69	$ .64	$ .22
Year ended December 31, 2005:				
Oil and gas revenues	$ 323,826	$ 320,337	$ 389,679	$ 419,398
Total revenues	$ 327,988	$ 332,477	$ 397,938	$ 486,195
Total costs and expenses	$ 278,355	$ 256,363	$ 318,988	$ 340,426
Net income	$ 84,657	$ 185,559	$ 123,573	$ 140,779
Net income per share:				
Basic	$ .59	$ 1.32	$ .90	$ 1.11
Diluted	$ .58	$ 1.28	$ .88	$ 1.08

During March and April 2006, the Company sold all of its interests in certain oil and gas properties in the deepwater Gulf of Mexico and its Argentine assets, respectively. During May and August 2005, the Company sold certain Canadian and United States Gulf of Mexico shelf assets, respectively. These divestitures qualified as discontinued operations pursuant to SFAS 144. In accordance with SFAS 144, the Company reclassified the results of operations and gains on the sales of the divested assets from continuing operations to discontinued operations in the Company's consolidated statements of operations. See Note V of Notes to Consolidated Financial Statements for additional information regarding these divestitures that gave rise to the adjustments in the tables above.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures. The Company's management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Exchange Act, the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Report. Based on that evaluation, the principal executive officer and principal financial officer concluded that the design and operation of the Company's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Changes in internal control over financial reporting. There have been no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the Company's last fiscal quarter that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2006, management assessed the effectiveness of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework", issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on management’s assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006. The report, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting".

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors and Stockholders of
Pioneer Natural Resources Company:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Pioneer Natural Resources Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (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.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as of December 31, 2006 and 2005 and the related consolidated statements of operations, stockholders' equity, cash flows and comprehensive income for each of the three years in the period ended December 31, 2006 of the Company and our report dated February 19, 2007 expressed an unqualified opinion thereon.

Ernst & Young LLP

Dallas, Texas
February 19, 2007

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2007 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2007 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about the Company's equity compensation plans as of December 31, 2006:

	Number of Securities to be Issued Upon Exercise of Outstanding Options (a)	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in First Column) (b)
Equity compensation plans approved by security holders (c):			
Pioneer Natural Resources Company:			
2006 Long-Term Incentive Plan	—	$ —	4,525,451
Long-Term Incentive Plan	1,464,609	$ 20.99	—
Employee Stock Purchase Plan	—	$ —	469,527
Predecessor plans	136,886	$ 14.39	—
	1,601,495		4,994,978

(a) There are no outstanding warrants or equity rights awarded under the Company's equity compensation plans. The securities do not include restricted stock awarded under the Company's previous Long-Term Incentive Plan and the 2006 Long-Term Incentive Plan (the "Plan").

(b) In May 2006, the stockholders of the Company approved the Plan, which provides for the issuance of up to 4.6 million shares of common stock. No additional awards may be made under the prior Long-Term Incentive Plan. The number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan is based on the original authorized issuance of 750,000 shares less 280,473 cumulative shares issued through December 31, 2006. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of each of the Company's equity compensation plans.

(c) All equity compensation plans have been approved by security holders.

The remaining information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2007 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2007 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2007 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements of the Company are included in "Item 8. Financial Statements and Supplementary Data":

Report of Independent Registered Pubic Accounting Firm

Consolidated Balance Sheets as of December 31, 2006 and 2005

Consolidated Statements of Operations for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Statements of Cash Flows for the Years Ended December 31, 2006, 2005 and 2004

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2006, 2005 and 2004

Notes to Consolidated Financial Statements

Unaudited Supplementary Information

(b) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(c) are included in the Company's Form 10-K filed with the SEC on February 20, 2007.

(c) Financial Statement Schedules

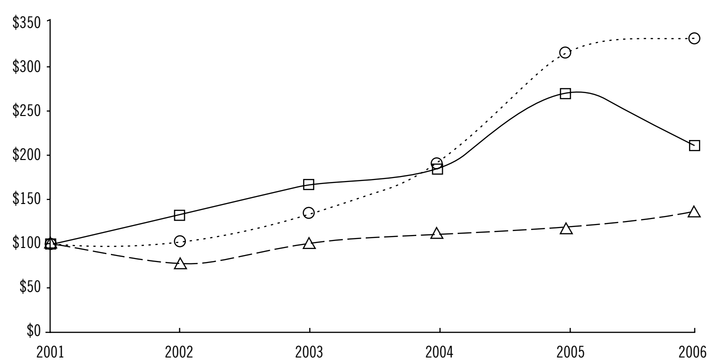
No financial statement schedules are required to be filed as part of this Report or they are inapplicable.

STOCK PERFORMANCE

The information contained in this "Stock Performance" section of the 2006 Annual Report is not a part of Pioneer's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 and shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission. Such information shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that Pioneer specifically incorporates such information.

The following graph and chart compare Pioneer's cumulative total stockholder return on common stock during the five-year period ended December 31, 2006, with cumulative total stockholder return during the same period for the Standard & Poors 500 Index ("S&P 500 Index") and the Dow Jones U.S. Exploration and Production Index ("DJ E&P Index"), as prescribed by the SEC rules. The following graph and chart shows the value, at December 31 in each of 2002, 2003, 2004, 2005 and 2006 of $100 invested at December 31, 2001, and assumes the reinvestment of all dividends:

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
AMONG PIONEER, THE S&P 500 INDEX AND THE DJ E&P INDEX (a)



	Year ended December 31, 2001	2002	2003	2004	2005	2006
Pioneer Natural Resources Company	$ 100	$ 131.10	$ 165.78	$ 183.36	$ 269.07	$ 209.58
S&P 500 Index	$ 100	$ 77.90	$ 100.24	$ 111.15	$ 116.61	$ 135.03
DJ E&P Index	$ 100	$ 102.17	$ 133.90	$ 189.97	$ 314.06	$ 330.93

(a) Assumes $100 invested on December 31, 2001 in stock or index, including reinvestment of dividends.

SHAREHOLDER INFORMATION

STOCK EXCHANGE LISTING-COMMON STOCK

New York Stock Exchange: PXD

CORPORATE HEADQUARTERS

Pioneer Natural Resources Company
5205 N. O'Connor Blvd., Suite 200
Irving, TX 75039
(972) 444-9001

Website: www.pxd.com

STOCK TRANSFER AGENT AND REGISTRAR

Communication concerning the transfer or exchange of shares, dividends, lost certificates or change of address should be directed to:

Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
(888) 509-5586
Website: www.continentalstock.com
E-Mail: pioneer@continentalstock.com

ANNUAL MEETING

The Annual Meeting of stockholders will be held Wednesday, May 16, 2007, at 9:00 a.m. CDT at the Dallas Marriott Las Colinas Hotel, 223 W. Las Colinas Blvd., Irving, Texas.

INFORMATION REQUESTS

To receive additional copies of the Annual Report on Form 10-K as filed with the Securities and Exchange Commission or to obtain other Pioneer publications, please contact:

Pioneer Natural Resources Company
Investor Relations
5205 N. O'Connor Blvd., Suite 200
Irving, TX 75039
(972) 969-3583
ir@pxd.com

INVESTOR RELATIONS/MEDIA CONTACTS

Shareholders, portfolio managers, brokers and securities analysts seeking information concerning Pioneer's operations or financial results are encouraged to contact Frank Hopkins, Vice President, Investor Relations at (972) 444-9001. Media inquiries should be directed to Susan Spratlen, Vice President, Corporate Communications and Public Affairs at (972) 444-9001.

CERTIFICATIONS

The CEO and CFO certifications required under Section 302 of the Sarbanes-Oxley Act were filed as exhibits to the most recently filed Form 10-K. In 2006, the Company submitted the CEO annual certification pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

OTHER OFFICE LOCATIONS

Pioneer Natural Resources UK Ltd.

David McManus, Vice President
International Operations
Midas House – 1st Floor
62 Goldsworth Rd.
Woking, Surrey GU21 6YLQ
UK
Telephone: 44 1483 741710

Pioneer Natural Resources Alaska, Inc.

Kenneth H. Sheffield, Jr., President
700 G Street, Suite 600
Anchorage, AK 99501
Telephone: (907) 277-2700

Pioneer Natural Resources Canada Inc.

Todd A. Dillabough, President
2900, 255-5th Avenue S.W.
Calgary, AB T2P 3G6
Canada
Telephone: (403) 231-3100

Pioneer Natural Resources Nigeria Ltd.

Gregg M. Moser, Managing Director
Plot 90 Ajose Adeogun Street - 3rd Floor
Victoria Island, Lagos, Nigeria
Telephone: 234 1 271 3733

Pioneer Natural Resources South Africa (PTY) Ltd.

Marek Ranoszek, General Manager
21st Floor, #1 Thibault Square
1 Long Street,
Cape Town 8001, RSA
Telephone: 27 21 425 5012

Pioneer Natural Resources Tunisia Ltd.

Hashim Alkhersan, General Manager
La Residence Lakeo - 3rd Floor
Rue Du Lac Michigan
Les Berges du Lac
1053 - Tunis, Tunisia
Telephone: 216 71 960 885

BOARD OF DIRECTORS

Scott D. Sheffield
Chairman and Chief Executive Officer

James R. Baroffio [3,4]
Former President
Chevron Canada Resources

Edison C. Buchanan [3,4]
Former Managing Director
Credit Suisse

R. Hartwell Gardner [2,4]
Retired Treasurer
Mobil Corporation

Linda K. Lawson [2,4]
Former Vice President
Williams Companies

Andrew D. Lundquist [3,4]
Managing Partner
Lundquist, Nethercutt & Griles LLC

Charles E. Ramsey, Jr. [1,3,4]
Financial Consultant

Frank A. Risch [2,4]
Retired Vice President and Treasurer
Exxon Mobil Corporation

Mark S. Sexton [4]
Chief Executive Officer
Evergreen Energy Inc.

Robert A. Solberg [2,4]
Retired Vice President
Texaco, Inc.

Jim A. Watson [2,4]
Senior Counsel
Carrington, Coleman,
Sloman & Blumenthal, L.L.P.

Committee Membership

[1] LEAD DIRECTOR [2] AUDIT COMMITTEE [3] COMPENSATION AND MANAGEMENT DEVELOPMENT COMMITTEE [4] NOMINATING AND CORPORATE GOVERNANCE COMMITTEE

OFFICERS

Scott D. Sheffield
Chairman and Chief Executive Officer

Timothy L. Dove
President and Chief Operating Officer

A. R. Alameddine
Executive Vice President,
Worldwide Negotiations

Mark S. Berg
Executive Vice President and
General Counsel

Chris J. Cheatwood
Executive Vice President,
Worldwide Exploration

Richard P. Dealy
Executive Vice President and
Chief Financial Officer

William F. Hannes
Executive Vice President,
Worldwide Business Development

Danny L. Kellum
Executive Vice President,
Domestic Operations

Jay P. Still
Executive Vice President,
Western Division

Thomas C. Halbouty
Vice President and
Chief Information Officer

Darin G. Holderness
Vice President and
Chief Accounting Officer

Frank E. Hopkins
Vice President, Investor Relations

Mark H. Kleinman
Vice President, Corporate Secretary
and Chief Compliance Officer

David McManus
Vice President,
International Operations

Larry N. Paulsen
Vice President, Administration and
Risk Management

Susan A. Spratlen
Vice President, Corporate
Communications and Public Affairs

Roger W. Wallace
Vice President, Government Affairs

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