PIONEER NATURAL RESOURCES CO
Form 10-K
February 21, 2008

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, 2007

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 o**

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 o** **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** **o**

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. **o**

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 **o** Non accelerated filer **o**

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). **Yes** **o** **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	**$ 5,878,496,549**
Number of shares of Common Stock outstanding as of February 19, 2008	**119,389,995**

Documents Incorporated by Reference:

(1) Proxy Statement for Annual Meeting of Shareholders to be held during May 2008 — Referenced in Part III of this report.

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PART III

PART IV

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.
- *"LNG"* means liquefied natural gas.
- *"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.
- *"MMcfpd"* means one million cubic feet per day.
- *"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 cash flows 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 ten 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, South Africa and Tunisia. Pioneer is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries.

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; London, England; Capetown, South Africa and Tunis, Tunisia. At December 31, 2007, the Company had 1,702 employees, 1,032 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, 2007.

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 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 well-trained experienced personnel who make prudent capital investment decisions, embrace technological innovation and are focused on 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 recent years, world oil prices increased in response to increases in demand from developing economies and the perceived threat of supply disruptions in the Middle East, Nigeria, Venezuela and other areas. In 2007, oil prices increased due to supply uncertainty surrounding Middle East conflicts and increasing world demand for both oil and refined products. A significant increase of refinery outages led to tightness in products markets which was responsible for oil price strength throughout much of the year. North American gas prices were generally consistent throughout 2007. Early 2007 price weakness, a result of a significant inventory overhang and mild weather, was largely offset by early fall when LNG imports to the Gulf Coast were reduced. LNG cargoes slated for delivery into the U.S. instead were sold into Asia and Europe in response to major demand increases brought on by harsh weather and large nuclear powered electric generation plant outages. Significant factors that will impact 2008 commodity prices include: developments in the issues currently impacting

Iraq and Iran and the Middle East in general; demand of Asian and European markets; 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 uncertain LNG deliveries to the United States. Perhaps the issue having the greatest impact on prices will be the strength of the U.S. economy and the prospect of a recession. In conjunction with the relatively higher commodity prices experienced during 2007, the Company also experienced increasing costs, particularly higher drilling and well servicing rig rates and drilling supplies.

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 2007, 2006 and 2005 from the Company's hedging activities and the Company's open hedge positions at December 31, 2007.

The Company. The Company's asset base is anchored by the Spraberry oil field located in West Texas, the Raton gas field located in southern Colorado, the Hugoton gas field located in southwest Kansas 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 Edwards Trend area of South Texas, the Barnett Shale area of North Texas, the Gulf of Mexico shelf, Mississippi and Alaska, and internationally in 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 among 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, financial, legal and management support to United States and foreign subsidiaries that explore for, develop and produce proved reserves. Production operations are principally located domestically in Texas, Kansas, Colorado, Alaska, Mississippi and the Gulf of Mexico shelf, and internationally in 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, 2007, the Company's average daily production, on a BOE basis, increased eight percent as a result of successful drilling programs in the United States and Tunisia and a five percent decrease in the delivery of VPP volumes. Production, price and cost information with respect to the Company's properties for 2007, 2006 and 2005 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, 2007, the Company drilled 2,608 gross (2,415 net) wells, 96 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $4.2 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, 2007 include proved undeveloped reserves and proved developed reserves that are behind pipe of 221 MMBbls of oil and NGLs and 1,003 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 geoscience staff as well as acquiring a portfolio of lower-risk exploration opportunities complemented by a limited number of higher-impact exploration opportunities. In 2008, the Company expects to spend approximately 90 percent of its $1.0 billion capital budget on low-risk development and resource play extension drilling in its four core onshore areas (Spraberry, Raton, Edwards Trend and Tunisia). The remaining ten percent will be focused primarily on development drilling in the Company's Alaskan Oooguruk project and Barnett Shale drilling. Exploratory and extension drilling involve 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 2007, 2006 and 2005, the Company invested $536.7 million, $223.2 million and $272.9 million, 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 of proved oil and gas properties during 2007, 2006 and 2005.

The Company periodically evaluates and pursues acquisition opportunities (including opportunities to acquire particular oil and gas assets or 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 2007, 2006 and 2005.

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 spot 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 2007, the Company's significant purchasers of oil, NGLs and gas were Plains Marketing LP (14 percent), Oneok Resources (11 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 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 2007, 2006 and 2005 from commodity hedging activities and the Company's open and terminated commodity hedge positions at December 31, 2007.

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 acquire such properties and the financial resources necessary to acquire and develop the properties. Higher recent commodity prices have increased the cost of oil and gas 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 is made known to 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.

Environmental matters and regulations. The Company's operations are subject to stringent and complex foreign, federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- enjoin some or all of the operations of facilities deemed in non-compliance with permits;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and gas drilling, production and transportation activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, United States Congress and state legislatures, federal and state agencies and foreign government and agencies frequently revise environmental laws and regulations, and the clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on the Company's operating costs.

The following is a summary of some of the existing laws, rules and regulations to which the Company's business operations are subject.

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency ("EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in the Company's costs to manage and dispose of wastes, which could have a material adverse effect on the Company's results of operations and financial position. Also, in the course of the Company's operations, it generates some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, and waste oils, that may be regulated as hazardous wastes.

Wastes containing naturally occurring radioactive materials ("NORM") may also be generated in connection with the Company's operations. Certain processes used to produce oil and gas may enhance the radioactivity of NORM, which may be present in oilfield wastes. NORM is not subject to regulation under the Atomic Energy Act of 1954, or the Low Level Radioactive Waste Policy Act. NORM is subject primarily to individual state radiation control regulations. In addition, NORM handling and management activities are governed by regulations promulgated by the Occupational Safety and Health Administration ("OSHA"). These state and OSHA regulations impose certain requirements concerning worker protection; the treatment, storage and disposal of NORM waste; the management of waste piles, containers and tanks containing NORM; as well as restrictions on the uses of land with NORM contamination.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, 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 currently owns or leases numerous properties that have been used for oil and gas exploration and production for many years. Although the Company believes it has utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on or under the properties owned or leased by the Company, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of the Company's properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under the Company's control. In fact, there is evidence that petroleum spills or releases have occurred in the past at some of the properties owned or leased by the Company. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination.

Water discharges and use. The Clean Water Act (the "CWA") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The primary federal law imposing liability for oil spills is the Oil Pollution Act ("OPA"), which sets minimum standards for prevention, containment and cleanup of oil spills. OPA applies to vessels, offshore facilities and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, may be subject to oil spill cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills.

Operations associated with the Company's properties also produce wastewaters that are disposed via injection in underground wells. These activities are regulated by the Safe Drinking Water Act (the "SDWA") and analogous state and local laws. The underground injection well program under the SDWA classifies produced wastewaters and imposes restrictions on the drilling and operation of disposal wells as well as the quality of injected wastewaters. This program is designed to protect drinking water sources and requires permits from the EPA or analogous state agency for the Company's disposal wells. Currently, the Company believes that disposal well operations on the Company's properties comply with all applicable requirements under the SDWA. However, a change in the regulations or the inability to obtain permits for new injection wells in the future may affect the Company's ability to dispose of produced waters and ultimately increase the cost of the Company's operations.

The waters produced by the Company's CBM operations also may be subject to the laws of various states and regulatory bodies regarding the ownership and use of water. For example, in connection with the Company's CBM operations in the Raton Basin in Colorado, water is removed from coal seams to reduce pressure and allow the methane to be recovered. Historically, these operations have been regulated by the state agency responsible for regulating oil and gas activity in the state. In a recent case brought by the owners of ranch land involving a CBM competitor in a different CBM basin in Colorado, a state water court held that the use of water in CBM operations should be subject to water-use regulation under an additional agency as is the case with other uses of water in the state, including the need for the obtaining of permits, possible competition with other claimants for the use of the water and the possibility of providing mitigation water for other water users. That decision is on appeal. However, if that ruling or a similar ruling or regulation becomes applicable to the Company's CBM or other oil and gas operations, the Company's ability to expand its operations could be adversely affected and these changes in regulation could ultimately increase the Company's cost of doing business.

Air emissions. The Federal Clean Air Act (the "CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. Such laws and regulations may require a facility to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions; obtain or strictly comply with air permits containing various emissions and operational limitations; or utilize specific emission control technologies to limit emissions of certain air pollutants. In addition, EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. Moreover, states can impose air emissions limitations that are more stringent than the federal standards imposed by EPA. Federal and state regulatory agencies can also impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas, may require the Company to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies for gas and oil exploration and production operations. In addition, some gas and oil production facilities may be included within the categories of hazardous air pollutant sources, which are subject to increasing regulation under the CAA. Failure to comply with these requirements could subject a regulated entity to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. Gas and oil exploration and production facilities may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Health and safety. The Company's operations are subject to the requirements of the federal Occupational Safety and Health Act (the "OSH Act") and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSH Act hazard communication standard, EPA community right-to-know regulations under Title III of CERCLA and similar state statues require that the Company organize and/or disclose information about hazardous materials used or produced in the Company's operations. The Company believes that it is in substantial compliance with these applicable requirements and with other OSH Act and comparable requirements.

Global warming and climate change. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states (not including Texas) have already taken legal measures to reduce emissions of greenhouse gases. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (*e.g.*, cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the United Nations Framework Convention on Climate Change, also known as the

"Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. or the adoption of regulations by the EPA and analogous state agencies that restrict emissions of greenhouse gases in areas in which the Company conducts business could have an adverse effect on the Company's operations and demand for oil and gas.

The Company believes it is in substantial compliance with all existing environmental laws and regulations applicable to the Company's current operations and that its continued compliance with existing requirements will not have a material adverse impact on the Company's financial condition and results of operations. For instance, the Company did not incur any material capital expenditures for remediation or pollution control activities for the year ended December 31, 2007. Additionally, the Company is not aware of any environmental issues or claims that will require material capital expenditures during 2008. However, accidental spills or releases may occur in the course of the Company's operations, and the Company cannot give any assurance that it will not incur substantial costs and liabilities as a result of such spills or releases, including those relating to claims for damage to property and persons. Moreover, the Company cannot give any assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on the Company's business, financial condition and results of operations.

Other regulation of the oil and gas industry. The oil and gas industry is regulated by numerous foreign, federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, foreign, federal and state, are authorized by statute to issue rules and regulations binding on the oil and gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and gas industry may increase the Company's cost of doing business by increasing the cost of transporting its production to market, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The Department of Homeland Security Appropriations Act of 2007 requires the Department of Homeland Security ("DHS") to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present "high levels of security risk." The DHS is currently in the process of adopting regulations that will determine whether some of the Company's facilities or operations will be subject to additional DHS-mandated security requirements. Presently, it is not possible to accurately estimate the costs the Company could incur, directly or indirectly, to comply with any such facility security laws or regulations, but such expenditures could be substantial.

Development and production. Development and production operations are subject to various types of regulation at foreign, federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, the posting of bonds in connection with various types of activities and filing reports concerning operations. Most states, and some counties and municipalities, in which the Company operates also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations at which the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGL and gas within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and gas that may be produced from the Company's wells, negatively impact the economics of production from these wells and/or to limit the number of locations the Company can drill.

Regulation of transportation and sale of gas. The availability, terms and cost of transportation significantly affect sales of gas. Foreign, federal and state regulations govern the price and terms for access to gas pipeline transportation. The interstate transportation and sale for resale of gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). The FERC's regulations for interstate gas transmission in some circumstances may also affect the intrastate transportation of gas.

Although gas prices are currently unregulated, Congress historically has been active in the area of gas regulation. The Company cannot predict whether new legislation to regulate gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on the Company's operations. Sales of condensate and gas liquids are not currently regulated and are made at market prices.

Gas gathering. While the Company owns or operates some gas gathering facilities, the Company also depends on gathering facilities owned and operated by third parties to gather production from its properties, and therefore the Company is impacted by the rates charged by such third parties for gathering services. To the extent that changes in foreign, federal and/or state regulation affect the rates charged for gathering services, the Company also may be affected by such changes. Accordingly, the Company does not anticipate that the Company would be affected any differently than similarly situated gas producers.

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.

The prices of oil, NGL and gas are at historically high levels and are highly volatile. A sustained decline in these commodity prices could adversely affect the Company's financial condition and results of operations.

The Company's revenues, profitability, cash flow and future rate of growth are highly dependent on commodity prices. Oil prices have recently been at historically high levels and gas prices have been at high levels over the past several years when compared to prior periods. Commodity prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- domestic and worldwide supply of and demand for oil, NGL and gas;
- weather conditions;
- overall domestic and global political and economic conditions, including those in the Middle East, Africa and South America;
- actions of OPEC and other state-controlled oil companies relating to oil price and production controls;
- the impact of increasing LNG deliveries to the United States;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

In the past, commodity prices have been extremely volatile, and the Company expects this volatility to continue. A significant downward trend in commodity prices would have a material adverse effect on the Company's revenues, profitability and cash flow. The Company makes price assumptions that are used for planning purposes, and a significant portion of the Company's cash outlays, including rent, salaries and noncancellable capital commitments, are 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 cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

The Company's hedging activities could result in financial losses.

To reduce exposure to fluctuations in commodity prices, the Company has entered into, and expects in the future to enter into, hedging arrangements for a portion of its oil and gas production. These hedging arrangements may expose the Company 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 commodity prices.

Exploration and development drilling may not result in commercially productive reserves.

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;
- restricted access to land for drilling or laying pipelines; and
- costs of, or shortages or delays in the delivery of, drilling rigs and 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, extension or exploratory, involves these risks, exploratory and extension 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 2008. Increased levels of drilling activity in the oil and gas industry in recent periods have led to increased costs of some drilling equipment, materials and supplies. If these trends continue in the future, they may impact the Company's profitability, cash flow and ability to complete development projects as scheduled.

Future price declines could result in a reduction in the carrying value of the Company's proved oil and gas properties, which could adversely affect the Company's results of operations.

Declines in commodity prices may result in the Company having to make substantial downward adjustments to the Company's estimated proved reserves. If this occurs, or if the Company's estimates of production or economic factors change, accounting rules may require the Company to write-down, as a noncash charge to earnings, the carrying value of the Company's oil and gas properties for impairments. The Company is required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of the Company's proved oil and gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of the Company's oil and gas properties, the carrying value may not be recoverable and therefore require a write-down. The Company may incur impairment charges in the future, which could materially affect the Company's results of operations in the period incurred.

The Company periodically evaluates its unproved oil and gas properties, and could be required to recognize noncash charges in the earnings of future periods.

At December 31, 2007, the Company carried unproved property costs of $277.5 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.

The Company may be unable to make attractive acquisitions, and any acquisition it completes is subject to substantial risks that could impact its business.

Acquisitions of producing oil and gas properties have been an important 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. Acquisition opportunities in the oil and gas industry are very competitive, which can increase the cost of, or cause the Company to refrain from, completing acquisitions. In addition, higher recent commodity prices have increased the cost of properties available for acquisition. The success of any acquisition will depend on a number of factors and involve potential risks, including among other things:

- the ability to estimate accurately the costs to develop the reserves, the recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;
- the assumption of unknown liabilities, losses or costs for which the Company is not indemnified or for which the indemnity the Company receives is inadequate;
- the validity of assumptions about costs, including synergies;
- the impact on the Company's liquidity or financial leverage of using available cash or debt to finance acquisitions;
- the diversion of management's attention from other business concerns; and
- an inability to hire, train or retain qualified personnel to manage and operate the Company's growing business and assets.

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 an acquisition, which may materially and adversely impact the desired benefits of the acquisition.

The Company may be unable to dispose of nonstrategic assets on attractive terms, and may be required to retain liabilities for certain matters.

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. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The Company periodically evaluates its goodwill for impairment, and could be required to recognize noncash charges in the earnings of future periods.

At December 31, 2007, the Company carried goodwill of $310.9 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 reduce the carrying value of goodwill for the impaired value, with a corresponding noncash charge to earnings in the period in which goodwill is determined to be impaired.

The Company's gas processing operations are subject to operational risks, which could result in significant damages and the loss of revenue.

As of December 31, 2007, the Company owned interests in four gas processing plants and ten treating facilities. The Company operates two of the gas processing plants and all ten 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.

The Company's operations involve many operational risks, some of which could result in substantial losses to the Company and unforeseen interruptions to the Company's operations for which the Company may not be adequately insured.

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 and fires;
- adverse weather effects;
- environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;
- high costs, shortages or delivery delays of equipment, labor or other services;
- facility or equipment malfunctions, failures or accidents;
- title problems;
- pipe or cement failures or casing collapses;
- compliance with environmental and other governmental requirements;
- lost or damaged oilfield workover and service tools;
- unusual or unexpected geological formations or pressure or irregularities in formations; and
- natural disasters.

Any of these risks 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.

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 above, 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.

The Company may not be able to obtain access to pipelines, gas gathering, transmission and processing facilities to market its oil and gas production.

The marketing of oil and gas production depends in large part on the availability, proximity and capacity of pipelines, gas gathering systems and other transportation, processing and refining facilities, as well as the existence of adequate markets. If there were insufficient capacity available on these systems, or if these systems were unavailable to the Company, the price offered for the Company's production could be significantly depressed, or the Company could be forced to shut-in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while it constructs its own facility. The Company also relies (and expects to rely in the future) on facilities developed and owned by third parties in order to process, transmit and sell its oil and gas production. The Company's plans to develop and sell its oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient transmission or processing facilities to the Company.

The nature of the Company's assets exposes it to significant costs and liabilities with respect to environmental and operational safety matters.

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 matters and regulations" 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 existing or 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.

The Company's credit facility and debt instruments have substantial restrictions and financial covenants that may restrict its business and financing activities.

The Company is a borrower under fixed rate senior notes, senior convertible notes and a credit facility. The terms of the Company's borrowings under the senior notes, senior convertible 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, 2007 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.

The Company faces significant competition and many of its competitors have resources in excess of the Company's available resources.

The oil and gas industry is highly competitive. The Company competes with a large number of companies, producers and operators in a number of areas such as:

- seeking to acquire oil and gas properties suitable for development or exploration;
- marketing oil, NGL and gas production; and
- seeking to acquire the equipment and expertise, including trained personnel, necessary to operate and develop properties.

Many of the Company's competitors are larger and have substantially greater financial and other resources than the Company. See "Item 1. Business — Competition, Markets and Regulations" above for additional discussion regarding competition.

The Company's business depends to a significant extent upon the continued service and performance of key senior managers and technical personnel.

The Company's 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 the Company's business, financial condition and results of operations.

The Company is subject to regulations that may cause it to incur substantial costs.

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.

The Company's international operations may be adversely affected by economic, political and other factors.

At December 31, 2007, approximately three percent of the Company's proved reserves were located outside the United States. The success and profitability of international operations may be adversely affected by risks associated with international activities, including:

- economic and labor conditions;
- war, terrorist acts and civil disturbances;
- political instability;

- loss of revenue, property and equipment as a result of actions taken by foreign countries where the Company has operations, such as expropriation or nationalization of assets and renegotiation, modification or nullification of existing contracts;
- changes in taxation policies (including host-country import-export, excise and income taxes and United States taxes on foreign subsidiaries);
- laws and policies of the United States and foreign jurisdictions affecting foreign investment, trade and business conduct; 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 in South Africa 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 proved reserves and future net cash flows are not precise. The actual quantities and net cash flows of the Company's proved reserves may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. The estimates of proved reserves and related future net cash flows 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 commodity 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 commodity 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;
- levels of future capital spending;
- 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 commodity prices 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 commodity 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 cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the ten percent discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general. 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.

The Company's actual production could differ materially from its 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.

The Company may be unable to complete its plans to repurchase its common stock.

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. From time to time, the Company may not be 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 repurchase programs will be commenced and, if so, that they will be completed.

The Company may be unable to complete its plans to form a master limited partnership in the time expected, or at all, and the structure and terms of any master limited partnership could change materially from those anticipated.

In April, 2007, the Company announced an intention to form two new master limited partnerships, which would own interests in long-lived, low-decline oil and gas assets. Although the Company's subsidiary, Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest"), has filed a preliminary registration statement (subject to completion) with the SEC for an initial public offering of limited partner interests, the Company announced in February 2008 that the offering had been postponed due to market conditions. In addition to market conditions, the completion of the Company's plans to form the master limited partnerships is subject to numerous other risks beyond the control of the Company, and therefore it is possible that one or both of the master limited partnerships will not be formed, will not complete an offering of securities, will not raise the planned amount of capital even if an offering of securities is completed, and will not be able to complete its proposed actions. Furthermore, the structure, nature, purpose, proposed assets and liabilities, and proposed manner of offering of the master limited partnerships may change materially from those anticipated. In addition, the Company's retained investment in any master limited partnership formed would be subject to the risks normally attendant to businesses in the oil and gas exploration and production industry, including most of the same risks to which the Company is subject. The Company's announcement of its plan with respect to Pioneer Southwest's initial public offering did not, and this report does not, constitute an offer to sell or the solicitation of an offer to buy any securities. Any offers, solicitations of offers to buy, or any sales of securities of either master limited partnership will be made only in accordance with the registration requirements of the Securities Act of 1933 or an exemption therefrom. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note W of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for discussions of Pioneer Southwest's proposed initial public offering.

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, 2007, 2006 and 2005, 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 86 percent, 89 percent and 82 percent of the Company's 2007, 2006 and 2005 proved reserves, respectively; and, 80 percent, 83 percent and 76 percent of the Company's 2007, 2006 and 2005 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.
- 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 audit of the Company's proved reserves and associated pre-tax present value discounted at ten percent, Pioneer 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 Pioneer'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 Pioneer with respect to ownership interest; oil and gas production; well test data; commodity 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 the pre-tax present value of such reserves discounted at ten percent. NSAI reviewed its audit differences with the Company, and, in a number of cases, held joint meetings with the Company to review additional reserves work performed by the technical teams and any updated performance data related to the reserve differences. Such data was incorporated, as appropriate, by both parties into the reserve estimates. NSAI's estimates, including any adjustments resulting from additional data, of those proved reserves and the pre-tax present value of such reserves discounted at ten percent did not differ from Pioneer's estimates by more than ten percent in the aggregate. However, when compared on a lease-by-lease, 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 do not exceed ten percent in the aggregate and NSAI is satisfied that the proved reserves and pre-tax present value of such reserves discounted at ten percent are reasonable and that its audit objectives have been met, NSAI will issue an unqualified audit opinion. Remaining differences are 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 letter, 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 petroleum engineering and evaluation principles.

The Company did not provide estimates of total proved oil and gas reserves during 2007, 2006 or 2005 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 963.8 MMBOE, 904.9 MMBOE and 986.7 MMBOE at December 31, 2007, 2006 and 2005, respectively, representing $9.0 billion, $4.7 billion and $7.3 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, 2007 (in MBOE):

	Production	**Extensions and Discoveries**	**Purchases of Minerals-in-Place**	**Sales of Minerals-in-Place**	**Revisions of Previous Estimates**
United States	(35,715)	44,571	50,424	(227)	21,495
Canada	(2,950)	10,755	—	(35,712)	(3,210)
South Africa	(1,151)	—	—	—	(4,485)
Tunisia	(1,557)	24,478	—	(11,771)	3,880
Total	(41,373)	79,804	50,424	(47,710)	17,680

Production. Production volumes include 2,891 MBOE of field fuel and 2,950 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 in the Company's Spraberry oil field, Raton gas field and the entry into the Barnett Shale gas field.

Sales of minerals-in-place. Sales of minerals-in-place are principally related to the Company's divestiture of its Canadian assets and the Tunisian government's election to participate in 50 percent of the Company's discoveries in the Cherouq concession in the Jenein Nord permit. 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 20 MMBOE of positive price revisions offset by 2 MMBOE of negative technical revisions. The Company's proved reserves at December 31, 2007 were determined using year-end NYMEX equivalent prices of $95.92 per barrel of oil and $6.80 per Mcf of gas, compared to $60.82 per barrel of oil and $5.64 per Mcf of gas at December 31, 2006.

On a BOE basis, 62 percent of the Company's total proved reserves at December 31, 2007 were proved developed reserves. Based on reserve information as of December 31, 2007, 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, 2007:

	Proved Reserves as of December 31, 2007				**2007 Average Daily Sales Volumes**		
	Oil & NGLs (MBbls) (in thousands)	**Gas (MMcf) (a)**	**MBOE**	**Standardized Measure**	**Oil & NGLs (Bbls)**	**Gas (Mcf) (b)**	**BOE**
United States	451,091	2,903,055	934,933	$ 8,265,557	37,196	316,418	89,933
South Africa	757	40,565	7,520	215,256	2,681	2,840	3,154
Tunisia	17,850	20,794	21,314	536,071	3,845	2,513	4,264
Total	469,698	2,964,414	963,767	$ 9,016,884	43,722	321,771	97,351

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(a) The gas reserves contain 290,599 MMcf of gas that will be produced and utilized as field fuel.

(b) The 2007 average daily sales volumes are from continuing operations and (i) do not include the field fuel produced, which averaged 47,526 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, 2007 (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**
2008	4,050	$ 289,199	$ 34,854	$ 547,631	$ (293,286)
2009	9,439	591,900	98,272	741,023	(247,395)
2010	13,517	818,245	126,394	584,203	107,648
2011	16,954	998,665	168,585	565,725	264,355
2012	19,144	1,105,860	189,013	466,388	450,459
Thereafter	304,410	18,937,469	4,052,416	979,991	13,905,062
	367,514	$ 22,741,338	$ 4,669,534	$ 3,884,961	$ 14,186,843

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(a)

Beginning in 2009 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling since 2008.

Description of Properties

United States

Approximately 89 percent of the Company's proved reserves at December 31, 2007 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 2007:

	Development Drilling Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	10	350	350	—	10
Mid-Continent	1	—	1	—	—
Rocky Mountains	5	230	233	2	—
Onshore Gulf Coast	2	16	18	—	—
Total United States	18	596	602	2	10

	Exploration/Extension Drilling Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	1	1	1	—	1
Rocky Mountains	16	19	15	2	18
Onshore Gulf Coast	4	19	19	1	3
Barnett Shale	—	6	6	—	—
Alaska	—	3	—	2	1
Total United States	21	48	41	5	23

The following table summarizes the Company's United States costs incurred by geographic area during 2007:

	Property Acquisition Costs Proved (in thousands)	Unproved	Exploration Costs	Development Costs	Asset Retirement Obligations	Total
Permian Basin	$ 56,232	$ 61,546	$ 23,395	$ 422,158	$ 2,987	$ 566,318
Mid-Continent	314	—	47	21,436	(951)	20,846
Rocky Mountains	164,730	43,502	71,467	180,340	29,813	489,852
Onshore Gulf Coast	6,367	6,364	148,756	140,130	1,507	303,124
Barnett Shale	99,133	87,788	23,351	—	1,320	211,592
Alaska	—	1,554	68,993	260,848 (a)	(218)	331,177
Gulf of Mexico						
Continuing operations	—	13	(1,269)	4,893	(1,315)	2,322
Discontinued operations	—	—	745	354	—	1,099
Total United States	$ 326,776	$ 200,767	$ 335,485	$ 1,030,159	$ 33,143	$ 1,926,330

(a) Includes $22.0 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 and drilling costs through economies of scale.

During July 2007, the Company entered into an agreement under which the Company has the option to purchase an additional 22 percent interest in the Spraberry Midkiff-Benedum gas processing system for $230 million, subject to normal closing adjustments. The additional 22 percent can be purchased in 2008 and 2009 and, if exercised, will increase the Company's interest in the system to 49 percent. In conjunction with this transaction, the Company extended its percent of proceeds ("POP") contract with the plant to 2022 and negotiated incremental increases in the Company's POP beginning in 2009.

In December 2007, the Company acquired approximately 44,000 gross acres in the Spraberry field for $89.4 million, with Pioneer being operator of the acquired properties. Proved reserves associated with the acquisition are approximately 15 MMBOE. The Company estimates that the acquisition provides more than 600 potential drilling locations utilizing 40-acre spacing.

During 2007, the Company (a) drilled 350 wells, an increase of over 17 percent compared to 2006, (b) acquired approximately 185,000 gross acres, bringing its total acreage position to approximately 869,000 gross acres (688,000 net acres), (c) completed several bolt-on property acquisitions and joint ventures and (d) successfully drilled a majority of the wells to the Wolfcamp formation. The Company plans to drill approximately 350 wells in 2008 and continue to pursue acreage expansions and bolt-on acquisitions.

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, approximately 990 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, which 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 65 MMcf of wet gas per day (i.e., gas production at the wellhead before processing or field fuel use and before reduction for royalties). Pioneer successfully led a cooperative effort with other operators in this field to effect rule changes which will enable further field development in future years. As part of the rule changes, the state-regulated production allowables were canceled as of December 31, 2007, and the Company received regulatory approval to commingle production from the Panoma and Council Grove formations. A commingling pilot program has been initiated and the Company is monitoring its production performance. To capitalize on these rule changes, future completion designs are being developed and continued optimization is planned for the existing field compression system.

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 1,365 Btuand is produced from approximately 675 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 the Fain gas processing plant for the field. As this field is operated at or below vacuum conditions, Pioneer continually works to improve compressor / gathering system efficiency. As part of this effort, approximately 17 miles of 16 inch pipeline was recently replaced in the heart of the field. The Company received regulatory relief in parts of the West Panhandle field to allow for future infill drilling locations.

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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 2005. The Company owns approximately 318,000 gross acres (231,000 net acres) in the center of the Raton Basin with current production from coal seams in the Vermejo and Raton formations. The Company owns the majority of the well servicing and frac equipment that it utilizes in the Raton field to control costs and insure availability. In the Raton field, the Company sells its gas at a Mid-Continent index price which historically has generally provided higher realized gas prices as compared to the Rockies-based indexes.

In December 2007, the Company acquired approximately 30,000 net acres in the Raton Basin for $205.3 million. The acquired acreage has approximately 95 Bcf of proved reserves.

During 2007, the Company (a) drilled 230 wells, and put 301 wells on production, (b) added wellhead compression and (c) continued efforts to optimize gathering and compression facilities. During 2008, the Company expects to complete approximately 175 wells.

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.

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 18 wells in six separate pilot areas and completed workovers and recompletions on 14 wells drilled by a previous operator. The Company completed the water treatment facilities and initiated sales of production in 2007. Determination of success of the pilot project is dependent on the ability to dewater the formation and determine if commercial quantities of gas can be produced. The pilot project is currently in the dewatering phase and a determination of commerciality should be known by the end of 2008.

Gas prices. In general, industry drilling success in the Rocky Mountains area (which affects the Company's properties in the Piceance/Uinta Basins and Sand Wash Basin) has created more supply than can be transported by the currently available pipeline infrastructure. As a result, gas prices in the region have experienced greater volatility and at the end of the third quarter of 2007 spot gas prices for the area were approximately $.60 per MMBtu. As a result of the extremely low gas prices during September and October of 2007, the Company shut-in approximately 5 to 6 MMcfpd of gas production in the Uinta/Piceance area. Additional pipeline capacity was added in the first quarter of 2008 with the start-up of the Rockies Express pipeline, which should alleviate the capacity constraints, allowing more gas to reach consumer markets at improved price levels. Prices have rebounded in the area since September 30, 2007 and the Company believes that gas prices will continue to improve as a result of the Rockies Express pipeline being in service.

Onshore Gulf Coast

South Texas. In 2007, the South Texas drilling program focused on the Edwards Trend, a tight gas limestone reservoir characterized by narrow bands of dry gas fields extending over 250 miles in length. The Company's drilling activity occurred in both established areas such as Pawnee field and growth areas along the Trend. To date the Company has acquired over 305,000 gross acres in the Edwards Trend. In addition to the Pawnee field, the Company has operations in the SW Kenedy, Sawfish, Word, Three Rivers and Washburn fields. Production depths in the Edwards Trend range from 9,500 feet to 14,500 feet.

During 2007, the Company drilled 20 exploration and appraisal wells targeting new field discoveries in the Edwards Trend growth areas with 100 percent success, exceeding expectations and increasing proved gas reserves. Nine of these new wells have been added to production, three wells are awaiting pipelines or testing, four are awaiting stimulation, and four are waiting on the horizontal lateral portion of the well to be completed. In previously established areas, including the Pawnee field, 14 wells were drilled with 100 percent success.

The acquisition of 3-D seismic data has significantly enhanced field development in all areas of the Edwards Trend, 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 is in the process of shooting and interpreting approximately 900 square miles of new data. Multiple surveys were completed in 2007 and more are planned for 2008.

In order to accommodate its rapidly growing Edwards Trend production, the Company significantly expanded its existing gas gathering and processing infrastructure during 2007. The expansion included over 30 miles of gathering system and three additional treating facilities were installed.

In 2008, the Company expects a comparable drilling program to that in 2007. Also planned are additional facilities expansions to accommodate increasing production.

Mississippi. The Company has built an acreage position covering multiple plays in the Mississippi Salt Basin and now holds leases and option interests covering approximately 150,000 net 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.

The Company drilled two successful Cotton Valley wells in the Bolton field and installed a gas treating facility to process the gas. The Company is permitting for a 3-D seismic shoot in 2008 for the Bolton field to better define the resource potential and future drilling plans.

Barnett Shale

During 2007, the Company participated in the drilling of six successful exploration wells on its approximate 9,300 gross acres in the Barnett Shale play that it acquired in the second quarter of 2007.

In December 2007, the Company expanded its Barnett Shale acreage position by completing a $144.3 million acquisition. The Company estimates proved reserves on the acreage to be approximately 13.5 MMBOE. The acreage being acquired contains more than 300 potential drilling locations, with most locations covered by 3-D seismic data.

The Company's total holdings in the Barnett Shale play now approximate 80,000 gross acres, with more than 450 potential drilling locations. The Company plans to drill 20 wells in 2008 with the expectation of increasing its drilling program in 2009.

Alaska

Oooguruk. In 2002, the Company acquired a 70 percent working interest and operatorship in ten state leases on Alaska's North Slope, and in 2003 drilled three exploratory wells 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 constructed and armored the gravel drilling and production island site in 2006. Installation of a subsea flowline and production facilities to carry produced liquids to existing onshore processing facilities at the Kuparuk River Unit was completed in 2007. Pioneer assembled the drilling rig on location and commenced drilling the first of approximately 40 horizontal development and injector wells in December of 2007. The Company estimates that first production will occur during the first half of 2008 and that first sales will occur mid-year 2008. During 2008, the Company expects to drill 13 to 15 of the 40 planned wells.

Cosmopolitan. In 2005, the Company acquired an interest in the Cosmopolitan Unit in the Cook Inlet of Alaska. Through a series of transactions, the Company now owns 100 percent of the Cosmopolitan Unit. The previous operator of the Cosmopolitan Unit had an oil discovery for which economic viability was not determined. During 2005 and 2006, the Company completed and interpreted a 3-D seismic shoot. During 2007, the Company drilled a lateral sidetrack from an existing wellbore at an onshore site to further appraise the resource potential of the unit. The initial unstimulated production test results were encouraging. The Company plans to begin permitting activities and continue facilities planning during 2008 for a future potential development of the project and to drill another appraisal well in 2009.

Onshore North Slope area. During the 2006-2007 winter drilling season, the Company participated in drilling two exploratory wells in the National Petroleum Reserve - Alaska ("NPRA") area, both of which were noncommercial.

Gulf of Mexico

Gulf of Mexico area. 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 began evaluation plans for the potential development of the discovery, but projected capital costs for the project doubled during the evaluation, which resulted in the Company electing to not pursue the development of the Clipper project. Accordingly, the Company recognized an exploration and abandonment charge of $72.1 million in the fourth quarter of 2007.

As a result of Hurricane Rita, the Company's East Cameron facility, located on the Gulf of Mexico shelf, was destroyed. Operations to reclaim and abandon the East Cameron facility began in 2007. During the second quarter of 2007, the Company increased the estimated cost to reclaim and abandon the East Cameron facility by $66.0 million to an aggregate estimated cost of $185 million. The estimate to reclaim and abandon the East Cameron facility is based upon an analysis prepared by a third-party engineering firm for the majority of the work, an estimate by the Company for the remaining work that was not covered by the third-party analysis and actual abandonment activity to date. See Note U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information on the East Cameron 322 facility.

International

The Company's international operations are located offshore South Africa and onshore in southern Tunisia. Additionally, the Company has an exploration permit in Equatorial Guinea. During 2007, the Company also disposed of its interests in Block 320 in Nigeria, and relinquished its remaining interest in Block 256 in Nigeria due to unsuccessful exploratory drilling results. The Company is currently winding up its efforts to exit Nigeria completely. In November 2007, the Company closed the sale of all of the Company's common stock in its Canadian subsidiaries for net proceeds of $525.7 million, resulting in a gain of $101.3 million. See Notes N, S and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of the Nigerian and Canadian divestitures. As of December 31, 2007, approximately three percent of the Company's proved reserves were located in Africa.

The following tables summarize the Company's international development and exploration/extension drilling activities during 2007:

Development Drilling

	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Divested Wells	Ending Wells In Progress
Canada	3	—	1	1	1	—
South Africa	2	1	3	—	—	—
Total International	5	1	4	1	1	—

	Exploration/Extension Drilling					
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Divested Wells	Ending Wells In Progress
Canada	16	17	7	6	20	—
Tunisia	5	12	12	4	—	1
West Africa - Nigeria	—	1	—	1	—	—
Total International	21	30	19	11	20	1

The following table summarizes the Company's international costs incurred by geographic area during 2007:

	Property Acquisition Costs		Exploration	Development		Asset Retirement	Total
	Proved	Unproved	Costs	Costs		Obligations	
	(in thousands)						
Canada – discontinued operations	$ 82	$ 3,620	$ 32,160	$ 63,450		$ 1,134	$ 100,446
South Africa	—	—	276	113,591	(a)	(2,413)	111,454
Tunisia	—	718	103,381	9,724		1,265	115,088
Other	—	—	5,149	—		—	5,149
West Africa:							
Equatorial Guinea	—	—	704	—		—	704
Nigeria	—	—	18,052	—		—	18,052
Total International	$ 82	$ 4,338	$ 159,722	$ 186,765		$ (14)	$ 350,893

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(a) Includes $10.5 million of capitalized interest related to the South Coast Gas project.

South Africa. The Company has agreements to explore for oil and gas covering over 3.6 million acres offshore the southern coast of South Africa 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 subsea tie-back of gas from the Sable field and five 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 prices. During 2007, two additional wells were drilled and installation of pipeline and facilities infrastructure was completed as part of the South Coast Gas project. First production from the South Coast Gas project was achieved in the third quarter of 2007 at approximately 15 to 20 MMcfpd (gross). It is expected that the simultaneous production of both oil and gas from the Sable field will increase the ultimately recoverable oil reserves.

A significant portion of the gas reserves associated with the South Coast Gas project is in the Sable field. Initially, the gas production from the Sable field was not expected to commence until the oil production was completed. However, as a result of production performance from the Sable field and improved oil prices, which have had the effect of extending the economic life of the Sable oil field, facilities modifications are being planned that would allow for the simultaneous production of oil and gas from the Sable field. The modifications are currently expected to be completed in late 2008 or early 2009.

Tunisia. The Company holds interests in four separate onshore permits located in the southern portion of Tunisia. These permits cover a gross area of approximately 11,900 square kilometers containing two production concessions targeting the Acacus formation with additional future upside exploration potential from this and other formations.

- **Jenein Nord Permit and Cherouq Concession.** The Jenein Nord Permit covers approximately 1,200 square kilometers. Over the past two years, the Company has conducted an intensive exploration program over the area. As a result of an aggressive seismic data acquisition and exploration drilling program, the Company achieved a significant number of hydrocarbon discoveries. Based on the success, the Company, along with the government oil agency, Enterprise Tunisienne d'Activities Petrolieres ("ETAP"), submitted a joint application on November 10, 2007 to the Directeur Général de l'Energie for the development of a portion of the permit area called the Cherouq Concession.

On December 17, 2007, the Consultative Committee of Hydrocarbons, the advisory committee to the Directeur Général de l'Energie, approved the Cherouq Concession resulting in the Company and ETAP each holding a 50 percent working interest in the concession. The concession covers approximately 760 square kilometers of the Jenein Nord Permit. During 2007, the Company drilled seven exploration wells and first production from the concession was achieved in late fourth quarter 2007.

The Company plans to drill up to seven additional wells and acquire an additional 295 square kilometers of 3-D seismic data over the Cherouq Concession during 2008.

- **Borj El Khadra Permit and Adam Concession.** The Borj El Khadra Permit, including the Adam Concession, covers approximately 2,900 square kilometers. Production from the Adam Concession began in May 2003, for which the Company now has a 20 percent working interest. During 2007, the Company continued its exploratory and appraisal activities on the Adam Concession by drilling four wells, of which all were successful, and completed drilling of two wells in the Borj El Khadra Permit, of which one was successful. The Company plans to drill an additional four wells in the Adam Concession and two wells in the Borj El Khadra exploration permit during 2008.

- **El Hamra Permit.** The El Hamra exploration permit covers approximately 4,000 square kilometers, of which the Company is operator with a 50 percent working interest during the exploration period. In 2007, the Company completed the acquisition of 310 kilometers of seismic data and began processing the data. Processing and interpretation of the seismic data is scheduled to be completed during the second quarter of 2008. The Company anticipates drilling an exploration well in the second half of 2008.

- **Anaguid Permit.** The Anaguid exploration permit covers approximately 3,800 square kilometers. In 2007, the Company acquired an additional 15 percent interest in the Anaguid exploration permit, thereby increasing its interest to 60 percent (during the exploration period) and resulting in the transfer of operations to Pioneer. The Company intends to acquire an additional 900 square kilometers of 3-D seismic data and expects to drill up to two exploration wells in the second half of 2008.

Equatorial Guinea. The Company owns a 50 percent interest in Block H in deepwater Equatorial Guinea, which covers over 240,000 acres. In late 2006, the Republic of Equatorial Guinea ratified a new hydrocarbons law, which among other things, appears to entitle Equatorial Guinea to increase substantially its carried interest in all concessions, including Block H. In addition, drilling costs have increased significantly beyond those originally anticipated. Given these and other facts, the Company and the other participants in the block have been unable to reach an agreement as to their respective rights and obligations under a joint operating agreement relating to the well operations in the block and as a result, the parties have commenced arbitration. In connection with the ongoing arbitration among the parties, the Company recognized an impairment charge of approximately $10.3 million to write off its remaining basis in Block H. See Note I of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's arbitration associated with Block H.

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, 2007, 2006 and 2005. 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 2007, 2006 and 2005. 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, 2007			
	United States	**South Africa**	**Tunisia**	**Total**
Production information:				
Annual sales volumes:				
Oil (MBbls)	6,804	979	1,403	9,186
NGLs (MBbls)	6,771	—	—	6,771
Gas (MMcf)	115,493	1,037	917	117,447
Total (MBOE)	32,825	1,151	1,557	35,533
Average daily sales volumes:				
Oil (Bbls)	18,643	2,681	3,845	25,169
NGLs (Bbls)	18,553	—	—	18,553
Gas (Mcf)	316,418	2,840	2,513	321,771
Total (BOE)	89,933	3,154	4,264	97,351
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 63.78	$ 76.36	$ 70.04	$ 66.08
NGL (per Bbl)	$ 41.60	$ —	$ —	$ 41.60
Gas (per Mcf)	$ 7.25	$ 6.76	$ 8.77	$ 7.26
Revenue (per BOE)	$ 47.30	$ 70.98	$ 68.33	$ 48.99
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 70.26	$ 76.72	$ 70.04	$ 70.91
NGL (per Bbl)	$ 41.60	$ —	$ —	$ 41.60
Gas (per Mcf)	$ 6.02	$ 6.76	$ 8.77	$ 6.04
Revenue (per BOE)	$ 44.31	$ 71.29	$ 68.33	$ 46.24
Average costs (per BOE):				
Production costs:				
Lease operating	$ 6.54	$ 22.43	$ 3.46	$ 6.91

Third-party transportation charges	0.97	—	1.57	0.97
Taxes:				
Ad valorem	1.33	—	—	1.23
Production	2.12	—	—	1.96
Workover	0.83	—	0.11	0.77
Total	$ 11.79	$ 22.43	$ 5.14	$ 11.84
Depletion expense	$ 10.27	$ 12.07	$ 5.01	$ 10.10

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2006			
	United States	South Africa	Tunisia	Total
Production information:				
Annual sales volumes:				
Oil (MBbls)	6,467	1,506	871	8,844
NGLs (MBbls)	6,748	—	—	6,748
Gas (MMcf)	103,928	—	436	104,364
Total (MBOE)	30,536	1,506	944	32,986
Average daily sales volumes:				
Oil (Bbls)	17,716	4,127	2,386	24,229
NGLs (Bbls)	18,488	—	—	18,488
Gas (Mcf)	284,732	—	1,195	285,927
Total (BOE)	83,659	4,127	2,585	90,371
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 65.73	$ 65.92	$ 63.16	$ 65.51
NGL (per Bbl)	$ 35.24	$ —	$ —	$ 35.24
Gas (per Mcf)	$ 6.15	$ —	$ 5.97	$ 6.15
Revenue (per BOE)	$ 42.64	$ 65.92	$ 61.05	$ 44.23
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 62.92	$ 65.74	$ 63.16	$ 63.42
NGL (per Bbl)	$ 35.24	$ —	$ —	$ 35.24
Gas (per Mcf)	$ 5.96	$ —	$ 5.97	$ 5.96
Revenue (per BOE)	$ 41.37	$ 65.74	$ 61.05	$ 43.04
Average costs (per BOE):				
Production costs:				
Lease operating	$ 5.64	$ 14.47	$ 1.99	$ 5.94
Third-party transportation charges.	0.81	—	1.42	0.79
Taxes:				
Ad valorem	1.45	—	—	1.35
Production	1.99	—	—	1.84
Workover	0.72	—	—	0.66
Total	$ 10.61	$ 14.47	$ 3.41	$ 10.58
Depletion expense	$ 9.07	$ 6.28	$ 4.25	$ 8.80

PRODUCTION, PRICE AND COST DATA – (Continued)

	Year Ended December 31, 2005			
	United States	South Africa	Tunisia	Total
Production information:				
Annual sales volumes:				
Oil (MBbls)	8,008	2,405	1,269	11,682
NGLs (MBbls)	6,352	—	—	6,352
Gas (MMcf)	98,927	—	—	98,927
Total (MBOE)	30,849	2,405	1,269	34,523
Average daily sales volumes:				
Oil (Bbls)	21,942	6,588	3,477	32,007
NGLs (Bbls)	17,403	—	—	17,403
Gas (Mcf)	271,033	—	—	271,033
Total (BOE)	84,517	6,588	3,477	94,582
Average prices, including hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 32.01	$ 53.01	$ 52.98	$ 38.61
NGL (per Bbl)	$ 31.72	$ —	$ —	$ 31.72
Gas (per Mcf)	$ 6.94	$ —	$ —	$ 6.94
Revenue (per BOE)	$ 37.09	$ 53.01	$ 52.98	$ 38.78
Average prices, excluding hedge results and amortization of deferred VPP revenue:				
Oil (per Bbl)	$ 54.05	$ 53.01	$ 52.98	$ 53.72
NGL (per Bbl)	$ 31.72	$ —	$ —	$ 31.72
Gas (per Mcf)	$ 7.26	$ —	$ —	$ 7.26
Revenue (per BOE)	$ 43.86	$ 53.01	$ 52.98	$ 44.84
Average costs (per BOE):				
Production costs:				
Lease operating	$ 4.55	$ 11.79	$ 1.66	$ 4.95
Third-party transportation charges	0.66	—	1.54	0.64
Taxes:				
Ad valorem	1.31	—	—	1.17
Production	1.94	—	—	1.73
Workover	0.53	—	—	0.48
Total	$ 8.99	$ 11.79	$ 3.20	$ 8.97
Depletion expense	$ 7.10	$ 10.19	$ 3.75	$ 7.19

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, 2007, 2006 and 2005:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**
As of December 31, 2007:						
United States	5,498	4,825	10,323	4,362	4,213	8,575
South Africa	3	5	8	1	2	3
Tunisia	13	—	13	3	—	3
Total	5,514	4,830	10,344	4,366	4,215	8,581
As of December 31, 2006:						
United States	4,889	4,253	9,142	3,916	3,932	7,848
Canada	48	832	880	31	699	730
South Africa	4	2	6	2	1	3
Tunisia	10	—	10	2	—	2
Total	4,951	5,087	10,038	3,951	4,632	8,583
As of December 31, 2005:						
United States	4,552	4,028	8,580	3,606	3,695	7,301
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	5,450	4,964	10,414	4,324	4,408	8,732

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(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, 2007, the Company owned interests in seven 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, 2007:

LEASEHOLD ACREAGE

	Developed Acreage	Undeveloped Acreage	Royalty

	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
United States:					
Onshore	1,414,288	1,209,915	2,782,979	1,446,940	294,908
Offshore	61,840	23,334	85,142	72,739	6,750
	1,476,128	1,233,249	2,868,121	1,519,679	301,658
South Africa	119,579	53,281	3,508,421	1,578,790	—
Tunisia	287,540	80,044	2,860,487	1,569,116	—
West Africa	—	—	244,881	122,441	—
Total	1,883,247	1,366,574	9,481,910	4,790,026	301,658

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2007:

	Acres Expiring (a)	
	Gross	**Net**
2008 (b)	1,026,197	556,110
2009	1,914,820	1,087,405
2010	1,230,688	666,252
2011	272,400	227,596
2012	133,499	93,894
Thereafter	4,904,306	2,158,769
Total	9,481,910	4,790,026

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

(b) Acres subject to expiration during 2008 include 827,308 gross acres (201,341 net acres) in Tunisia and 198,889 gross acres (153,427 net acres) in North America. In Tunisia, the Company has received extensions, plans to make the necessary expenditures to extend the acreage or intends to seek extensions on the 2008 expirations. As to the remaining acreage, the Company may extend the leases prior to their expiration based upon 2008 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 2007, 2006 and 2005. 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,		
	2007	2006	2005	2007	2006	2005
United States:						
Productive wells:						
Development	602	662	537	581	619	505
Exploratory	41	52	40	33	42	37
Dry holes:						
Development	2	8	7	2	7	7
Exploratory	5	8	7	3	6	5
	650	730	591	619	674	554
Argentina:						
Productive wells:						
Development	—	14	65	—	14	64
Exploratory	—	4	19	—	4	18
Dry holes:						
Development	—	1	4	—	1	4
Exploratory	—	2	14	—	2	14
	—	21	102	—	21	100
Canada:						
Productive wells:						
Development	1	2	27	1	2	26
Exploratory	7	326	87	5	297	72
Dry holes:						
Development	1	—	—	—	—	—
Exploratory	6	16	7	5	15	7
	15	344	121	11	314	105
South Africa:						
Productive wells:						
Development	3	2	—	1	1	—
Exploratory	—	—	1	—	—	—
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	—	1	—	—	1	—
	3	3	1	1	2	—
Tunisia:						
Productive wells:						
Development	—	—	—	—	—	—
Exploratory	12	2	2	8	1	1
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	4	2	2	3	—	1
	16	4	4	11	1	2
West Africa:						
Productive wells:						
Development	—	—	—	—	—	—
Exploratory	—	—	—	—	—	—

Dry holes:						
Development	—	—	—	—	—	—
Exploratory	1	1	1	—	—	—
	1	1	1	—	—	—
Total	685	1,103	820	642	1,012	761
Success ratio (a)	97 %	95 %	85 %	98 %	95 %	84 %

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(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, 2007:

	Gross Wells	Net Wells
United States:		
Development	10	9
Exploratory	23	14
	33	23
Tunisia:		
Exploratory	1	1
Total		