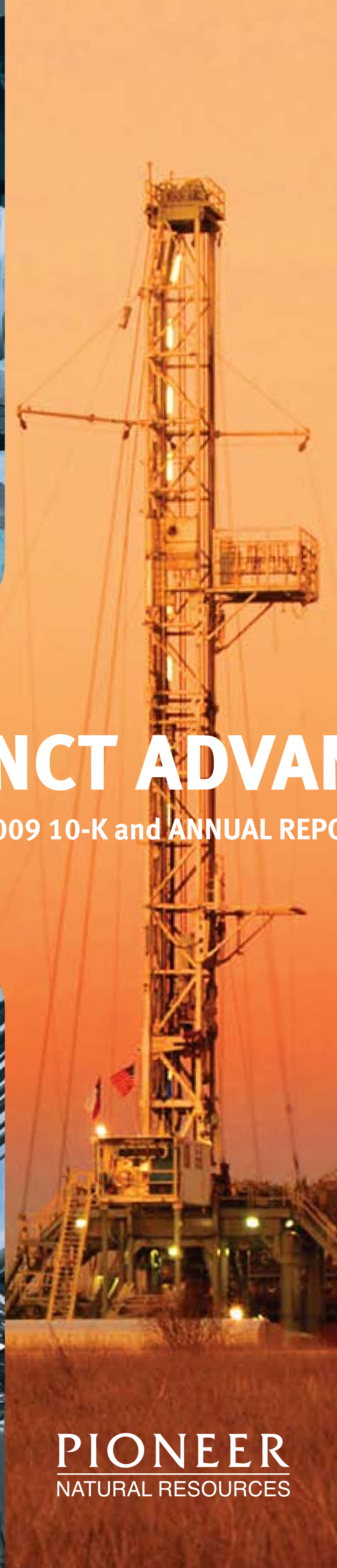
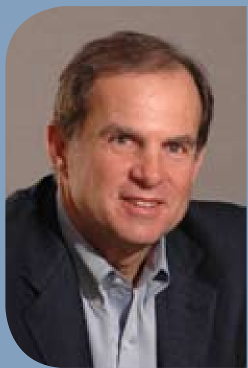




DISTINCT ADVANTAGE

2009 10-K and ANNUAL REPORT


PIONEER
NATURAL RESOURCES



Pioneer's 2009 stock price performance far exceeded that of our peer group, and we were the 14th best performer in the entire S&P 500 for the year.

FELLOW SHAREHOLDERS:

We are very pleased with Pioneer's performance during 2009 — a year of challenging economic conditions but significant success in reducing costs, optimizing operations, enhancing reserve potential and strengthening our financial position.

Pioneer's 2009 stock price performance far exceeded that of our peer group, gaining 198% for the year compared to the peer group which was up an average of 67%. Consequently, Pioneer was the 14th best performer in the entire S&P 500 for the year.

Oil prices strengthened through 2009, but natural gas prices declined and were weak through much of the year. The NYMEX spot price for oil started the year at approximately $45 per barrel. By summer, it had risen to approximately $70 per barrel, and it closed the year at almost $80 per barrel. The NYMEX spot price for natural gas, which started the year at nearly $6 per thousand cubic feet (Mcf), declined in early 2009 to range from $3 per Mcf to $4 per Mcf through much of the year before temporarily rising during the fourth quarter to again end the year at nearly $6 per Mcf.

2009 RESULTS

Facing low oil and gas prices in early 2009, we severely limited our capital expenditures to preserve capital and ensure free cash flow while we waited for well costs to adjust to the lower commodity price environment. Pioneer drilled or participated in a total of 78 wells during 2009, down from 614 wells during 2008. Despite this very limited drilling program, production per share rose 5% to approximately 115,000 barrels oil equivalent (BOE) per day, reflecting the strength of our low-decline, long-lived oil and gas assets. Pioneer also added 52 million BOE of proved reserves at an all-in finding and development cost of $9.15 per BOE, excluding price-related revisions.

By limiting our capital spending, we reduced long-term debt by $205 million (excluding $67 million of long-term debt associated with our publicly-traded master limited partnership). Pioneer recorded a net loss attributable to common shareholders for 2009 of $52 million, or $.46 per diluted share. Cash flow from operating activities for the year was $543 million.

The increase in production per share was primarily attributable to oil production growth from three areas. In the Spraberry field in West Texas, production rose for the fourth consecutive year despite a limited 2009 drilling program, as the benefits of Pioneer's larger 2008 Spraberry drilling program carried over into 2009. On the North Slope of Alaska, oil production from Pioneer's Oooguruk field more than quadrupled compared to 2008, in response to drilling seven successful wells. Tunisia oil production also increased over prior-year levels.

Across the Company, we focused significant effort on reducing production costs and had considerable success. We achieved substantial reductions in electricity, water disposal, well servicing, facilities and compression costs. Pioneer also worked with service providers to reduce drilling and completion costs in preparation for reactivating our drilling programs when fundamentals strengthened and prices improved.

LIQUIDS-RICH FOCUS FOR 2010

While oil prices have strengthened, the outlook for natural gas prices is not as clear. Therefore, expected rates of return heavily favor investments in oil or liquids-rich plays, at least in the near-term. Pioneer is one of the most liquids-rich independents in North America, and our strategy of maintaining a balance between oil and gas assets has proven to be a significant advantage in this environment, providing us with the flexibility to direct the majority of our capital investments toward oil and liquids-rich plays. Our long history in these plays also gives us the distinct advantage of established acreage positions, experience, the best technologies and existing infrastructure.

The Spraberry field is the largest onshore oil field in the U.S. lower 48 states, and Pioneer is the largest producer in the field, producing more than the next four companies combined. We hold approximately 900,000 acres, or approximately one-half of the field — the advantage of more than 30 years of Spraberry operating experience. We have had significant success with opening up additional pay from non-traditional organic-rich shale/silt zones and with extending well depths to include the deeper Wolfcamp zone. We have more than 20,000 drilling locations in the field, and including the potential for incremental reserves and production from these additional pay zones and enhanced recovery from waterflooding, our Spraberry holdings give us exposure to more than 1.1 billion BOE of net resource potential.

We are aggressively ramping up our Spraberry drilling program and plan to be running 19 rigs by mid-year and 24 rigs by year end. Approximately 425 Spraberry wells are expected to be drilled during 2010, generating quarter-to-quarter production growth. Beyond 2010, we plan to continue adding rigs to reach our targeted drilling pace of approximately 1,000 wells per year. To control costs, we've contracted drilling pipe, pumping units and sand supplies at attractive prices to meet our needs over the next few years. We are also expanding our integrated services, making relatively minor investments to enlarge our fracture stimulation fleet and to purchase drilling rigs and other equipment.

The Eagle Ford Shale play in South Texas is getting a great deal of attention for the enhanced value of the liquids-rich gas produced in a large part of the play. As with the Spraberry, Pioneer has a distinct advantage in this play arising from our history of operating in the area. Pioneer has drilled more than 150 wells into the Edwards formation that lies below the Eagle Ford Shale. We hold approximately 310,000 gross acres in the play and have approximately 2,000 square miles of 3-D seismic data, logs from more than 150 operated wells, micro-seismic data and proprietary core samples.

Pioneer has drilled three successful discovery wells which flowed at some of the highest gas and liquids rates reported to date in the play. We are currently operating a two-rig horizontal drilling program, targeting liquids-rich areas. To accelerate development of Pioneer's substantial acreage position, we are actively pursuing a joint venture partner and expect to receive final bids by mid-year. We have 1,750 potential drilling locations and expect to expand our drilling program with our joint venture partner during the second half of 2010.

Pioneer was the first independent to operate on the North Slope of Alaska, discovering the Oooguruk oil field in 2003 and initiating development drilling in early 2008. The 2010 drilling program will target the Kuparuk and Nuiqsut formations and is expected to again generate significant oil production growth. A third reservoir will also be tested during the first half of 2010.

The Spraberry field is the largest onshore oil field in the U.S. lower 48 states, and Pioneer is the largest producer in the field.

In Tunisia, Pioneer's oil drilling program resumes during 2010, with plans to drill three new prospects identified from recent 3-D seismic results and to participate in two non-operated wells. The drilling program is expected to generate strong oil production growth in 2010. South Africa natural gas production will also continue and benefit from stronger oil prices as the natural gas price is indexed to oil.

Until natural gas prices strengthen, we will continue to limit natural gas drilling. In the meantime, Pioneer's Rockies and Mid-Continent teams are maintaining their focus on controlling costs and optimizing production. We can afford to be patient, because these natural gas assets have the advantage of long lives and steady but slow production declines. These two assets generate significant excess cash flow that is essential to our plans to aggressively expand drilling in oil and liquids-rich areas through 2012. Our Barnett Shale team expects to reinitiate limited drilling later this year to test an opportunity in a more liquids-rich area of the play. In the Edwards Trend of South Texas, drilling will be curtailed until natural gas prices strengthen on a sustained basis.

The advantage of high-quality oil and gas assets and a disciplined strategy was evident during 2009.

Sustained support for the price of natural gas depends on increasing U.S. demand. The United States stands at an energy crossroad. The advantage of significant new natural gas resources from unconventional domestic sources, primarily shale formations, has been a topic of broad discussion and extensively studied. These new natural gas resources offer our nation a plentiful supply of a cleaner-burning domestic alternative to coal and imported oil. Expanding the use of natural gas provides an immediate opportunity, using existing technology, to reduce emissions and reduce reliance on imported oil. I am optimistic that the expected growth in demand will support higher natural gas prices and allow us to reactivate our natural gas drilling programs.

In 2010, we expect to generate free cash flow with capital spending of $800 million to $900 million (excluding acquisitions, asset retirement obligations, capitalized interest and geological and geophysical general and administrative costs). Our primary objective is increasing net asset value for our shareholders, and approximately 90% of total capital spending is oil focused. With this capital program and the continued benefit of our stable long-lived assets, we expect to post strong growth in production per share during 2010 and to continue to enhance our financial flexibility. In 2011 through 2015, with the distinct advantage of approximately 22,000 potential oil and liquids-rich drilling locations, we expect to deliver double-digit growth in production per share.

In the year since my last letter to shareholders, much has changed, but our people continue to be Pioneer's greatest strength. Our employees were essential to our success in weathering the tough times of 2009 and in re-activating and accelerating oil drilling as we headed into 2010. By giving and generously volunteering their time in partnership with Pioneer, they supported their communities and positively impacted the lives of others. Our employees dedicated themselves to protecting the environment and maintaining a safe workplace, taking pride in upholding our corporate values. I thank them for their commitment and support.

The advantage of high-quality oil and gas assets and a disciplined strategy was evident during 2009. Despite a substantial reduction in drilling activity, we delivered year-over-year production growth, free cash flow and improved financial flexibility. During 2010, with stronger oil prices, higher cash flow and an active drilling program, that advantage should be even more apparent.

We appreciate your support.

Scott D. Sheffield

Scott D. Sheffield
Chairman and CEO

FORWARD-LOOKING STATEMENTS:
Except for historical information contained herein, the statements in this document are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer Natural Resources Company are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described in Items 1, 1A, 7 and 7A and on page 5 of Pioneer's Form 10-K included with this report.

Cautionary Note to U.S. Investors — The U.S. Securities and Exchange Commission (the "SEC") prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. In this letter, Pioneer includes estimates of quantities of oil and gas using certain terms, such as "resource potential" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit Pioneer from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Pioneer. U.S. investors are urged to consider closely the disclosures in the Company's periodic filings with the SEC, available from the Company at 5205 N. O'Connor Blvd., Suite 200, Irving, Texas 75039, Attention: Investor Relations, and the Company's website at www.pxd.com. These filings also can be obtained from the SEC by calling 1-800-SEC-0330.

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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2009
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** ☒ **No** ☐

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **Yes** ☒ **No** ☐

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

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

Large accelerated filer	☒	**Accelerated filer**	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	**Smaller reporting company**	☐

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

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	**$**	**2,891,492,634**
Number of shares of Common Stock outstanding as of February 23, 2010		**115,550,322**

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the definitive proxy statement for Annual Meeting of Shareholders to be held during May 2010 as referenced in Part III of this report.

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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.
- *"DD&A"* means depletion, depreciation and amortization.
- *"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.
- *"IPO"* means initial public offering.
- *"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.
- *"Mont Belvieu–posted-price"* means the daily average natural gas liquids components as priced in *Oil Price Information Service* ("OPIS") in the table "U.S. and Canada LP – Gas Weekly Averages" at Mont Belvieu, Texas.
- *"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.
- *"Pioneer Southwest"* means Pioneer Southwest Energy Partners L.P. and its subsidiaries.
- *"proved reserves"* means the quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

  (i) The area of the reservoir considered as proved includes: (A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geosciences and engineering data.

  (ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

  (iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program is based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- *"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 employed in the determination of proved reserves and a ten percent discount rate.
- *"U.S."* means United States of America.
- *"VPP"* means volumetric production payment.
- 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.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

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 and its subsidiaries ("Pioneer" or the "Company") 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. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it. Accordingly, no assurances can be given that the actual events and results will not be materially different from the anticipated results described in the forward-looking statements. See "Item 1. Business — Competition, Markets and Regulations," "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" 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. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

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, 2009, the Company had 1,888 employees, 1,151 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, net asset value and net asset value per share. The strategies employed to achieve this mission are predicated on maintaining financial flexibility and capital allocation discipline while enhancing net asset value per share through accretive drilling programs, acquisitions, debt reduction, dividend distributions and share repurchases. 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 88 percent of the Company's proved oil and gas reserves as of December 31, 2009.

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 that, 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. Beginning in the second half of 2008 and continuing throughout 2009, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. During this same time period, North American gas supply increased as a result of the rise in domestic unconventional gas production. The combination of lower energy demand due to the economic slowdown and higher North American gas supply resulted in significant declines in oil, NGL and gas prices. While oil and NGL prices started to steadily improve beginning in the second quarter of 2009, gas prices remained volatile throughout 2009 due to high storage levels and increasing gas supply. The outlook for a worldwide economic recovery in 2010 remains uncertain and, therefore, the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, it is likely that commodity prices during 2010 will continue to be volatile.

For the several years preceding the 2008 economic slowdown, the petroleum industry had generally been characterized by volatile but upward-trending oil, NGL and gas commodity prices. During that period, 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 and the first half of 2008, oil prices increased due to supply uncertainty surrounding

Middle East conflicts and increasing world demand for both oil and refined products. A significant increase in refinery outages led to tightness in products markets, which was responsible for oil price strength throughout much of 2007 and the early part of 2008. North American gas prices increased during the first half of 2008 as a result of reduced inventory levels and a perceived shortage of North American gas supply and an anticipation that the United States would become a larger importer of LNG, which was selling at a substantial premium to United States gas prices in the world market. However, by mid-year 2008 it became increasingly apparent that the capital investment in gas drilling and discoveries of significant gas reserves in United States' shale plays would be more than sufficient to meet the Unites States demand. Coupled with the economic slowdown experienced in the second half of 2008, the increased supply of gas resulted in a sharp decline in North American gas prices.

Significant factors that the Company expects to impact 2010 commodity prices include: the effect of economic stimulus initiatives being implemented in the United States and worldwide in response to the worldwide economic slowdown; developments in the issues affecting 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 manage oil supply through export quotas; and overall North American gas supply and demand fundamentals.

To mitigate the impact of commodity price volatility on the Company's net cash provided by operating activities and its net asset value, Pioneer utilizes commodity derivative contracts. Although the Company has entered into derivative contracts on a large portion of its forecasted production through 2012, a sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which the Company could enter into derivative contracts on additional volumes in the future. As a result, the Company's internally-generated cash flows would be reduced for affected periods. Significant or extended price declines could also adversely affect the amount of oil, NGL and gas that the Company can produce economically. The duration, timing and magnitude of any period of lower commodity prices cannot be predicted. A sustained decline in commodity prices could result in a shortfall in expected cash flows, which could negatively affect the Company's liquidity, financial position and future results of operations. 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 effect on oil, NGL and gas revenues during 2009, 2008 and 2007 from the Company's derivative price risk management activities and the Company's open derivative positions at December 31, 2009.

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 Eagle Ford and Edwards Trend areas of South Texas, the Barnett Shale area of North Texas 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 and Alaska, 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, 2009, the Company's average daily production, on a BOE basis, increased three percent as compared to 2008 as a result of a full year of production from the successful development drilling programs in the Spraberry field during 2008, the addition of the Sable gas well during the fourth quarter of 2008 to production from the South Coast gas project in South Africa, development activities in Tunisia and a seven percent decrease in scheduled deliveries of VPP volumes. Production, price and cost information with respect to the Company's properties for 2009, 2008 and 2007 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, 2009, the Company drilled 1,203 gross (1,154 net) development wells, 99 percent of which were successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $2.4 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, 2009 include proved undeveloped reserves and proved developed reserves that are behind pipe of 186 MMBbls of oil, 66 MMBbls of NGLs and 870 Bcf of gas. The Company believes that its current portfolio of proved reserves provides attractive development opportunities for at least the next five years. The timing of the development of these reserves will be dependent upon commodity prices, drilling and operating costs and the Company's expected operating cash flows and financial condition.

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. 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 — Exploration and development drilling may not result in commercially productive reserves" 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 2009, 2008 and 2007, the Company invested $88.9 million, $137.6 million and $536.7 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 2009, 2008 and 2007.

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 analyses, oil and gas reserve analyses, due diligence, the submission of indications of interest, preliminary negotiations, negotiation of letters of intent or negotiation of definitive agreements. The success of any acquisition is uncertain and depends on a number of factors, some of which are outside the Company's control. See "Item 1A. Risk Factors — The Company may be unable to make attractive acquisitions, and any acquisition it completes is subject to substantial risks that could adversely affect its business."

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 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 and discontinued operations during 2009, 2008 and 2007.

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, in three geographic areas. 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 prices, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand 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 2009, the Company's significant purchasers of oil, NGLs and gas were Plains Marketing LP (10 percent), ConocoPhillips (9 percent), Occidental Energy Marketing, Inc. (7 percent), Enterprise Products Partners L.P. (6 percent) and Oneok Resources (5 percent). The Company believes that the loss of any one purchaser would not have a material adverse effect on its ability to sell its oil, NGL and gas production.

Derivative risk management 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. As of January 31, 2009, the Company discontinued hedge accounting and began accounting for its derivative contracts using the mark-to-market ("MTM") method of accounting. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of the Company's derivative risk management 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 about the impact of commodity derivative activities on oil, NGL and gas revenues and net derivative losses during 2009, 2008 and 2007, as well as the Company's open and terminated commodity derivative positions at December 31, 2009.

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. 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.

Securities 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 and internal controls over financial reporting, and ensuring 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. Failure to comply with the rules and regulations of the SEC could subject the Company to litigation from public or private plaintiffs. Failure to comply with the rules of the NYSE could result in the de-listing of the Company's common stock, which could have an adverse effect on the market price of the Company's commons stock. Compliance with some of these rules and 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, the United States Congress and state legislatures, federal and state regulatory 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 (the "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 oil or gas are currently regulated under RCRA's non-hazardous waste provisions. 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 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 used 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 by 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 injection wells are regulated by the Safe Drinking Water Act (the "SDWA") and analogous state and local laws. The underground injection well program under the SDWA requires permits from the EPA or analogous state agency for the Company's disposal wells, establishes minimum standards for injection well operations, and restricts the types and quantities of fluids that may be injected. 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. In addition, the United States Congress is considering amending the SDWA to require additional regulation of chemicals used by the oil and gas industry in the hydraulic fracturing process, and some states are considering similar regulations.

The water 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, the Colorado Supreme Court held that water produced in connection with the CBM operations should be subject to state water-use regulations administered by a different agency that regulates other uses of water in the state, including requirements to obtain permits for diversion and use of surface and subsurface water, an evaluation of potential competing uses of the water, and a possible requirement to provide mitigation water for other water users. The Company's CBM or other oil and gas operations and 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, the 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 the 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.

The Texas Commission on Environmental Quality (the "TCEQ") recently concluded an analysis of air emissions of third-party operators in the Barnett Shale area in response to reported concerns about high concentrations of benzene in the air near drilling sites and gas processing facilities. The TCEQ's investigation revealed elevated levels of benzene and other emissions at certain locations. The agency has announced that it will continue monitoring emissions and will investigate all complaints about oil and gas activities in the Barnett Shale area within 12 hours of receipt. The agency's investigations could lead to more stringent air permitting, increased regulation and possible enforcement actions against producers, including Pioneer, in the Barnett Shale area. In addition, environmental groups have advocated for increased regulation in the Barnett Shale area, and at least one state representative has advocated a moratorium on the issuance of drilling permits for new gas wells in the area. Any adoption of laws, regulations, orders or other legally enforceable mandates governing gas drilling and operating activities in the Barnett Shale that result in more stringent drilling or operating conditions or limit or prohibit the drilling of new gas wells for any extended period of time could increase the Company's costs and/or reduce its production, which could have a material adverse effect on the Company's results of operations and cash flows.

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 related 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 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. On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases," or "GHGs," present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the CAA. In late September 2009, the EPA had proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of GHGs from motor vehicles and that could also lead to the imposition of GHG emission limitations in CAA permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring in 2010. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company's equipment and operations could require the Company to incur costs to reduce emissions of GHGs associated with the Company's operations or could adversely affect demand for the oil, NGL and gas that the Company produces.

Also, on June 26, 2009, the U.S. House of Representatives approved adoption of the "American Clean Energy and Security Act of 2009" ("ACESA"), which is also known as the "Waxman-Markey cap-and-trade legislation." The purpose of ACESA is to control and reduce emissions of greenhouse gases in the United States. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA's overall emission reduction goals. As the number of GHG emission allowances permitted by ACESA declines each year, the cost or value of allowances would be expected to escalate significantly. The net effect of ACESA would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and gas. The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law.

In addition, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Finally, other nations have been seeking to reduce emissions of GHGs 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 GHGs to below 1990 levels by 2012. Depending on the particular jurisdiction in which the Company's operations are located, it could be required to purchase and surrender allowances for GHG emissions resulting from the Company's operations.

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 effect 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, 2009. Additionally, the Company is not aware of any environmental issues or claims that will require material capital expenditures during 2010. 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 effect 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. For example, the Company's properties located in Colorado are subject to the authority of the Colorado Oil & Gas Conservation Commission (the "COGCC"). The COGCC has recently promulgated new rules that are likely to increase the Company's costs of permitting and environmental compliance, and to extend waiting periods for the acquisition of permits.

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 affect the economics of production from these wells, 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. As a result of initiatives like FERC Order No. 636 ("Order 636"), issued in April 1992, the interstate gas transportation and marketing system has been substantially restructured to remove various barriers and practices that historically limited non-pipeline gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order 636 require that interstate pipelines provide firm and interruptible transportation service on an open access basis that is equal for all gas supplies. In many instances, the results of Order 636 and related initiatives have been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of gas in favor of providing only storage and transportation services.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, EPAct 2005 amends the Natural Gas Act ("NGA") to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as the Company, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to $1.0 million per day per violation. The anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under Order 704 (defined below).

In December 2007, the FERC issued rules ("Order 704") requiring that any market participant, including a producer such as the Company, that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus during a calendar year must annually report such sales and purchases to the FERC. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist the FERC in monitoring those markets and in detecting market manipulation.

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 or gas prices 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 affected 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 occurs, it 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 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. Commodity prices may fluctuate widely in response to relatively minor changes in the supply of and demand for oil, NGL and gas, market uncertainty and a variety of additional factors that are beyond the Company's 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;
- actions of OPEC and other state-controlled oil companies relating to oil price and production controls;
- the effect of LNG deliveries to the United States;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;
- the effect 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. For example, oil prices reached record levels in July 2008 of $145.29 per Bbl before declining to $33.87 per Bbl in December, while gas prices reached $13.58 per Mcf before declining to $5.29 per Mcf over the same period. During 2009, oil prices increased from a low of $33.98 per Bbl in February to a high of $81.37 per Bbl in October while gas prices declined from $6.07 per Mcf in January to $2.51 per Mcf in September. 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 the expectations on which these commitments were based, 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.

Significant or extended price declines could also adversely affect the amount of oil, NGL and gas that the Company can produce economically. A reduction in production could result in a shortfall in expected cash flows and require the Company to reduce capital spending or borrow funds to cover any such shortfall. Any of these factors could negatively affect the Company's ability to replace its production and its future rate of growth.

The Company could experience periods of higher costs if commodity prices rise. Such increases could reduce the Company's profitability, cash flow and ability to complete development activities as planned.

Historically, the Company's capital and operating costs have risen during periods of increasing oil, NGL and gas prices. These cost increases result from a variety of factors beyond the Company's control, such as increases in the cost of electricity, steel and other raw materials that the Company and its vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in the Company's revenue, thereby negatively impacting the Company's profitability, cash flow and ability to complete development activities as planned.

The Company's derivative risk management activities could result in financial losses.

To achieve more predictable cash flow and to manage the Company's exposure to fluctuations in the prices of oil, NGL and gas, the Company's strategy is to enter into derivative arrangements covering a portion of its oil, NGL and gas production. These derivative arrangements are subject to mark-to-market accounting treatment, and the changes in fair market value of the contracts will be reported in the Company's statement of operations each quarter, which may result in significant net gains or losses. These derivative contracts may also expose the Company to risk of financial loss in certain circumstances, including when:

- production is less than the contracted derivative volumes,
- the counterparty to the derivative contract defaults on its contract obligations, or
- the derivative contracts limit the benefit the Company would otherwise receive from increases in commodity prices.

On the other hand, failure to protect against declines in commodity prices exposes the Company to reduced revenue and liquidity when prices decline, as occurred in late 2008 and during 2009.

The failure by counterparties to the Company's derivative risk management activities to perform their obligations could have a material adverse effect on the Company's results of operations.

The use of derivative risk management transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. If any of these counterparties were to default on its obligations under the Company's derivative arrangements, such a default could have a material, adverse effect on the Company's results of operations, and could result in a larger percentage of the Company's future production being subject to commodity price changes.

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;
- unexpected 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, equipment and personnel.

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 2010. 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. Although the Company has experienced some decrease in these costs over the past year, such decreases could be short-lived. A return to the trends of increasing demand and costs in the future may affect the Company's profitability, cash flow and ability to complete development projects as scheduled and on budget.

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's 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 impair, as a noncash charge to earnings, the carrying value of the Company's oil and gas properties. The Company is required to perform impairment tests on proved oil and gas properties whenever events or changes in circumstances indicate that the carrying value of proved properties may not be recoverable. 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 an impairment charge will be required to reduce the carrying value of the proved properties to their estimated fair value. For example, during 2009, the Company recognized impairment charges of

$21.1 million due to the impairment of the Company's net assets in the Uinta/Piceance areas, primarily due to declines in gas prices and downward adjustments to the economically recoverable resource potential. 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, 2009, the Company carried unproved property costs of $236.7 million. GAAP requires periodic evaluation of these costs on a project-by-project basis. 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 adversely affect 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. The success of any acquisition will depend on a number of factors and involves potential risks, including among other things:

- the inability 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 affect 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 current economic outlook has affected the level of sales activity for oil and gas properties. The higher cost of credit has limited third parties' ability to acquire properties, and the potential value of the Company's properties is likely to decline if adverse economic conditions continue.

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, 2009, the Company carried goodwill of $309.3 million associated with its United States reporting unit. Goodwill is tested for impairment annually during the third quarter using a July 1 assessment date, and also whenever facts or circumstances indicate that the carrying value of the Company's goodwill may be impaired, requiring an estimate of the fair values of the reporting unit's assets and liabilities. Those assessments may be affected by (a) future reserve adjustments both positive and negative, (b) results of drilling activities, (c) changes in management's outlook on commodity prices and costs and expenses, (d) changes in the Company's market capitalization, (e) changes in the Company's weighted average cost of capital and (f) changes in income taxes. If the fair value of the reporting unit's net assets is not sufficient to fully support the goodwill balance in the future, 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, 2009, the Company owned interests in four gas processing plants and eleven treating facilities. The Company operates two of the gas processing plants and all eleven of the 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 development 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.

The Company 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. For example, in 2008, damage caused by Hurricanes Gustav and Ike to a third-party facility that fractionates NGLs from a portion of the Company's production resulted in a portion of the Company's production being shut in or curtailed from early September to mid-November 2008 while repairs and maintenance to the facility were being completed.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development, exploratory and infill drilling and enhanced recovery activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs and drilling results. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately result in the realization of proved reserves or meet the Company's expectations for success. As such, the Company's actual drilling and enhanced recovery activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

The Company may not be able to obtain access to pipelines, gas gathering, transmission, storage 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 and storage facilities, 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 store, 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, storage or processing facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist.

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.

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, 2009 and the terms associated therewith.

The Company's ability to obtain additional financing is also affected 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" for additional discussion regarding competition.

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. For example, the Company's properties located in Colorado are subject to the authority of the Colorado Oil & Gas Conservation Commission (the "COGCC"), which recently passed certain rules that will increase the length of time needed to obtain certain permits and will increase the Company's costs of permitting and environmental compliance. In addition, in connection with the Company's CBM operations in the Raton Basin in Colorado, the Colorado Supreme Court recently affirmed a state water court holding that water produced in connection with CBM operations should be subject to state water-use regulations, including regulations requiring permits for diversion and use of surface and subsurface water, an evaluation of potential competing permits, possible uses of the water and a possible requirement to provide augmentation water supplies for water rights owners with more senior rights. There can be no assurance that present or future regulations will not adversely affect the Company's business and operations, including that the Company may be required to suspend drilling operations or shut in production pending compliance. See "Item 1. Business — Competition, Markets and Regulations" for additional discussion regarding government regulation.

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

At December 31, 2009, two 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, 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 "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, transportation 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, NGLs 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 proved reserves and cash flows based on the same available data. The Company's actual production, revenues and expenditures with respect to proved 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 average prices preceding the date of the estimate 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, NGLs and gas; and
- changes in governmental regulations or taxation.

The Company reports all proved reserves held under concessions utilizing the "economic interest" method, which excludes the host country's share of proved reserves. Estimated quantities 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. In general, it requires the use of commodity prices that are based upon a 12-month unweighted average, as well as operating and development costs being incurred at the end of the reporting period. 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 from existing wells and the outcome of future drilling activity. Should these estimates prove inaccurate, actual production could be adversely affected. In addition, the Company's forecasts assume that none of the risks associated with the Company's oil and gas operations summarized in this Item 1A occur, such as facility or equipment malfunctions, adverse weather effects, or downturns in commodity prices or significant increases in costs, which could make certain drilling activities or production uneconomical.

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.

A subsidiary of the Company acts as the general partner of a publicly-traded limited partnership. As such, the subsidiary's operations may involve a greater risk of liability than ordinary business operations.

A subsidiary of the Company acts as the general partner of Pioneer Southwest Energy Partners L.P., a publicly-traded limited partnership formed by the Company to own and acquire oil and gas assets in its area of operations. As general partner, the subsidiary may be deemed to have undertaken fiduciary obligations to the partnership. Activities determined to involve fiduciary obligations to others typically involve a higher standard of conduct than ordinary business operations and therefore may involve a greater risk of liability, particularly when a conflict of interest is found to exist. Any such liability may be material.

A failure by purchasers of the Company's production to perform their obligations to the Company could require the Company to recognize a pre-tax charge in earnings and have a material adverse effect on the Company's results of operation.

While the credit markets, the availability of credit and the equity markets have improved during 2009, the economic outlook for 2010 remains uncertain. To the extent that purchasers of the Company's production rely on access to the credit or equity markets to fund their operations, there could be an increased risk that those purchasers could default in their contractual obligations to the Company. If for any reason the Company were to determine that it was probable that some or all of the accounts receivable from any one or more of the purchasers of the Company's production were uncollectible, the Company would recognize a pre-tax charge in the earnings of that period for the probable loss.

The Company may not be able to obtain funding, obtain funding on acceptable terms or obtain funding under its current credit facility in the event of a deterioration of the credit and capital markets, which could hinder or prevent the Company from meeting its future capital needs.

During 2009, access to the debt and equity capital markets improved. However, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets was higher than historical levels as many lenders and institutional investors increased interest rates, enacted tighter lending standards and limited the amount of funding available to borrowers.

If these events were to recur, the Company could be unable to obtain adequate funding under its current credit facility because (i) the Company's lending counterparties may be unwilling or unable to meet their funding obligations or (ii) the amount the Company may borrow under its current credit facility could be reduced as a result of lower oil, NGL or gas prices, declines in reserves, stricter lending requirements or regulations, or for other reasons. For example, the Company's credit facility requires that the Company maintain a specified ratio of the net present value of the Company's oil and gas properties to total debt, with the variables on which the calculation of net present value is based (including assumed commodity prices and discount rates) being subject to adjustment by the lenders. Due to these factors, the Company cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, the Company may be unable to implement its business plans or otherwise take advantage of business opportunities or respond to competitive pressures any of which could have a material adverse effect on the Company's production, revenues and results of operations.

Declining general economic, business or industry conditions could have a material adverse affect on the Company's results of operations.

Concerns over the worldwide economic outlook, geopolitical issues, the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased volatility and diminished expectations for the global economy. These factors, combined with volatile oil prices, declining business and consumer confidence and increased unemployment, precipitated a worldwide recession. Concerns about global economic growth have had a significant adverse effect on global financial markets and commodity prices, both of which contributed to a decline in the Company's share price and corresponding market capitalization during 2008. If the economic climate in the United States or abroad deteriorates, demand for petroleum products could further diminish, which could further depress the prices at which the Company can sell its oil, NGLs and gas and ultimately decrease the Company's net revenue and profitability.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama's proposed Fiscal Year 2011 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Each of these changes is proposed to be effective for taxable years beginning, or in the case of costs described in (ii) and (iv), costs paid or incurred, after

December 31, 2010. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. Any such change could negatively affect the Company's financial condition and results of operations.

The adoption of climate change legislation by Congress or regulation by the EPA could result in increased operating costs and reduced demand for the oil, NGLs and gas the Company produces.

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases," or "GHGs," present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company's equipment and operations could require the Company to incur costs to reduce emissions of GHGs associated with the Company's operations or could adversely affect demand for the oil, NGL and gas that the Company produces.

Also, on June 26, 2009, the United States House of Representatives approved adoption of ACESA. The purpose of which is to control and reduce emissions of greenhouse gases in the United States. The United States Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. It is not possible at this time to predict with certainty whether climate change legislation will be enacted, but any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require the Company to incur increased operating costs and could have an adverse effect on demand for the oil, NGLs and gas it produces. See "Competition, Markets and Regulations" in "Item 1. Business."

The adoption of derivatives legislation by the United States Congress could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity price risk associated with its business.

The United States Congress currently is considering comprehensive financial reform legislation that includes restrictions on certain transactions involving derivatives. This legislation also would provide the Commodity Futures Trading Commission ("CFTC") with express authority to impose position limits related to energy commodities, such as oil and gas. Separately, the CFTC is proposing regulations to set position limits for certain futures and option contracts in the major energy markets. Although it is not possible at this time to predict whether or when the CFTC may adopt rules or the United States Congress may act on derivatives legislation, any laws or regulations that may be adopted could have an adverse effect on the Company's ability to utilize derivative instruments to reduce the effect of commodity price risk associated with its business.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The United States Congress is currently considering legislation to amend the federal Safe Drinking Water Act to regulate chemicals used by the oil and gas industry in the hydraulic fracturing process, and some other states are considering similar regulations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and gas production. Sponsors of bills currently pending before the United States Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation also would require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory agencies, which could make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase the Company's costs of compliance and doing business.

Provisions of the Company's charter documents and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for the Company's common stock.

Provisions in the Company's certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of the Company or a merger in which the Company is not the surviving company and may otherwise prevent or slow changes in the Company's board of directors and management. In addition, because the Company is incorporated in Delaware, it is governed by the provisions of Section 203 of the Delaware General Corporation Law. The Company has also adopted a shareholder rights plan. These provisions could discourage an acquisition of the Company or other change in control transaction and thereby negatively affect the price that investors might be willing to pay in the future for the Company's common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Reserve Rule Changes

During 2009, the SEC issued its final rule on the modernization of oil and gas reporting (the "Reserve Ruling") and the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update No. 2010-03 ("ASU 2010-03") "Extractive Industries – Oil and Gas," which aligns the estimation and disclosure requirements of FASB Accounting Standards CodificationTopic 932 with the Reserve Ruling. The Reserve Ruling and ASU 2010-03 are effective for Annual Reports on Form 10-K for fiscal years ending on or after December 31, 2009. The key provisions of the Reserve Ruling and ASU 2010-03 are as follows:

- Expanding the definition of oil- and gas-producing activities to include the extraction of saleable hydrocarbons, in the solid, liquid or gaseous state, from oil sands, coalbeds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction;
- Amending the definition of proved oil and gas reserves to require the use of an average of the first-day-of-the-month commodity prices during the 12-month period ending on the balance sheet date rather than the period-end commodity prices;
- Adding to and amending other definitions used in estimating proved oil and gas reserves, such as "reliable technology" and "reasonable certainty";
- Broadening the types of technology that a reporter may use to establish reserves estimates and categories; and
- Changing disclosure requirements and providing formats for tabular reserve disclosures.

Reserve Estimation Procedures and Audits

The information included in this Report about the Company's proved reserves as of December 31, 2009, 2008 and 2007, which are located in the United States, South Africa and Tunisia, is based on evaluations prepared by (i) the Company's engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), with respect to the Company's major properties, and (ii) the Company's engineers, with respect to all other properties. The Company has no oil and gas reserves from non-traditional sources. Additionally, the Company does not provide optional disclosure of probable or possible reserves.

Reserve estimation procedures. The Company has established internal controls over reserve estimation processes and procedures to support the accurate and timely preparation and disclosure of reserve estimates in accordance with SEC and GAAP requirements. These controls include oversight of the reserves estimation reporting processes by Pioneer's Worldwide Reserves Group ("WWR"), and annual external audits of substantial portions of the Company's proved reserves by NSAI.

The management of Pioneer's oil and gas assets is decentralized geographically by individual asset teams who are responsible for the oil and gas activities in each of the Company's Permian Basin, Rockies, Mid-Continent, South Texas (which is now being further decentralized stratigraphically into the South Texas - Eagle Ford Shale and South Texas - Edwards asset teams), Barnett Shale, Alaska and Africa asset teams (the "Asset Teams"). The Company's Asset Teams are each staffed with reservoir engineers and geoscientists who prepare reserve estimates for the assets that they manage at the end of each calendar quarter using reservoir engineering information technology. There is shared oversight of the Asset Teams' reservoir engineers by the Asset Teams' managers and the Director of the WWR, each of whom is in turn subject to direct or indirect oversight by the Company's Chief Operating Officer ("COO") and management committee ("MC"). The Company's MC is comprised of its Chief Executive Officer, COO, Chief Financial Officer and other Executive Vice Presidents. Asset Teams' reserve estimates are reviewed by the asset team reservoir engineers before being submitted to the Director of the WWR and are summarized in reserve reconciliations that quantify reserve changes represented by revisions of previous estimates, purchases of minerals-in-place, extensions and discoveries, production and sales of minerals-in-place. All reserve estimates, material assumptions and inputs used in reserve estimates and significant changes in reserve estimates are reviewed for engineering and financial appropriateness and compliance with SEC and GAAP standards by the WWR. The MC reviews the reserve estimates and any differences with NSAI (for the portion of the reserves audited by NSAI) on a consolidated basis before these estimates are approved. The engineers and geoscientists who participate in the reserve estimation and disclosure process attended training on the Reserve Ruling by external consultants and/or through internal Pioneer programs. Additionally, the WWR has prepared and maintains an internal document for the asset teams to reference on reserve estimation and preparation to promote objectivity in the preparation of the Company's reserve estimates and SEC and GAAP compliance in the reserve estimation and reporting process.

Proved reserves audits. The reserve audits performed by NSAI in the aggregate represented 93 percent, 87 percent and 86 percent of the Company's 2009, 2008 and 2007 proved reserves, respectively; and, 86 percent, 80 percent and 80 percent of the Company's 2009, 2008 and 2007 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 which is included as an exhibit to this Report, 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.

See "Item 1A. Risk Factors," "Critical Accounting Estimates" in "Item 7. Management's Discussion and Analysis and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" for additional discussions regarding proved reserves and their related cash flows.

Qualifications of reserves preparers and auditors. The WWR is staffed by petroleum engineers with extensive industry experience and is managed by the Director of WWR, the technical person that is primarily responsible for overseeing the Company's reserves estimates. These individuals meet the professional qualifications of reserves estimators and reserves auditors as defined by the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information," promulgated by the Board of the Society of Petroleum Engineers. The WWR Director's qualifications include 32 years of experience as a petroleum engineer, with 25 years focused on reserves reporting for independent oil and gas companies, including Pioneer. His educational background includes an undergraduate degree in Chemical Engineering and a Masters of Business Administration degree in Finance. He is also a Chartered Financial Analyst ("CFA") and a member of the Oil and Gas Reserves Committee of the Society of Petroleum Engineers.

NSAI provides worldwide petroleum property analysis services for energy clients, financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. The technical person primarily responsible for auditing the Company's reserves estimates has been a practicing consulting petroleum engineer at NSAI since 1983 and has over 30 years of practical experience in petroleum engineering, including 29 years of experience in the estimation and evaluation of proved reserves. He graduated with a Bachelor of Science degree in Chemical Engineering in 1978 and meets or exceeds the education, training and experience requirements set forth in the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Board of the Society of Petroleum Engineers.

Technologies used in reserves estimates. The Company uses reliable technologies to establish additions to reserve estimates, The Company uses includes a combination of seismic data and interpretation, wireline formation tests, geophysical logs, and core data to calculate reserves estimates.

Proved reserves

The Company's proved reserves totaled 898.6 MMBOE, 959.6 MMBOE and 963.8 MMBOE at December 31, 2009, 2008 and 2007, respectively, representing \$3.3 billion, \$3.2 billion and \$9.0 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, 2009 (in MBOE):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Sales of Minerals-in-Place	Revisions of Previous Estimates
United States	(41,088)	14,785	—	(2,319)	(25,660)
South Africa	(1,690)	—	—	—	(703)
Tunisia	(2,485)	—	—	—	(1,780)
Total	(45,263)	14,785	—	(2,319)	(28,143)

Production. Production volumes include 3,004 MBOE of field fuel.

Extensions and discoveries. Extensions and discoveries are primarily comprised of discoveries in the Company's South Texas Edwards Trend and extension drilling in the North Texas Barnett Shale play, the Spraberry field and Alaska.

Sales of minerals-in-place. Sales of minerals-in-place are principally related to the divestment of the Company's Gulf of Mexico shelf and Mississippi properties. 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 65 MMBOE of negative price revisions offset by 37 MMBOE of positive technical revisions. The Company's proved reserves at December 31, 2009 were determined using the average of the first-day-of-the-month commodity prices during the 12-month period ending December 31, 2009 of \$61.14 per barrel of oil and \$3.87 per Mcf of gas, compared to \$44.60 per barrel of oil and \$5.71 per Mcf of gas as of December 31, 2008.

Tabular proved reserves disclosures. On a BOE basis, 58 percent of the Company's total proved reserves at December 31, 2009 were proved developed reserves. Based on reserve information as of December 31, 2009, and using the Company's production information for the year then ended, 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 by geographic area as of and for the year ended December 31, 2009:

	Summary of Oil and Gas Reserves as of December 31, 2009 Based on Average Fiscal-Year Prices				
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	MBOE (b)	Standardized Measure (b)
			(in thousands)		
Developed:					
United States	135,568	93,015	1,671,052	507,092	$ 2,512,221
South Africa	217	—	25,790	4,516	71,905
Tunisia	8,478	—	22,880	12,291	169,035
	144,263	93,015	1,719,722	523,899	2,753,161
Undeveloped:					
United States	180,025	63,818	779,079	373,689	558,628
Tunisia	1,048	—	—	1,048	18,765
	181,073	63,818	779,079	374,737	577,393
	325,336	156,833	2,498,801	898,636	$ 3,330,554

(a) The gas reserves contain 310,463 MMcf of gas that will be produced and utilized as field fuel.

(b) See Unaudited Supplementary Information included in "Item 8. Financial Statements and Supplementary Data" for information regarding the impact of the Reserve Ruling and ASU 2010-03 on the Company's proved reserves and Standardized Measure.

Proved undeveloped reserves. As of December 31, 2009, the Company has 4,582 proved undeveloped well locations (all of which are expected to be developed within the five years ended December 31, 2014), representing a decrease of 395 proved undeveloped well locations (eight percent) since December 31, 2008. The decrease in proved undeveloped well locations during 2009 is primarily attributable to decreases in Raton basin well locations due to gas price revisions that rendered certain locations uneconomic under proved reserve pricing guidelines and 114 undeveloped well locations that were drilled and completed as developed wells during 2009, at a net cost of $76.3 million. During 2008, the Company initiated cost reduction initiatives that included minimizing drilling activities until margins improved as a result of (i) commodity price increases and/or (ii) well cost reductions. Associated therewith, the Company significantly curtailed development expenditures during the first nine months of 2009. As a result of the successes realized from the aforementioned cost reduction initiatives and increases in 2009 oil prices, the Company implemented a plan to resume oil- and liquids-rich-gas-focused drilling activities during 2010 and has targeted its 2010 capital budget at $800 million to $900 million, excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs. The Company's proved undeveloped well locations as of December 31, 2009 include 1,675 well locations that have remained undeveloped for five years or more. Approximately 93 percent of the Company's proved undeveloped well locations that have remained undeveloped for five years or more are comprised of locations in the Spraberry field of West Texas in the Permian Basin. The Company recorded four proved undeveloped well locations and 2 MMBOE of proved undeveloped reserves in the United States under the reliable technology and reasonable certainty provisions of the Reserve Ruling, which would not have been recorded under the rules existing prior to the Reserve Ruling.

The following table represents the estimated timing and cash flows of developing the Company's proved undeveloped reserves as of December 31, 2009 (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
2010	1,874	$ 88,586	$ 19,008	$ 293,305	$ (223,727)
2011	6,693	280,931	53,081	619,957	(392,107)
2012	12,705	500,917	94,827	902,030	(495,940)
2013	18,289	721,328	136,294	1,052,605	(467,571)
2014	24,025	958,942	178,621	1,171,222	(390,901)
Thereafter	311,151	12,005,180	3,935,060	194,532	7,875,588
	374,737	$ 14,555,884	$ 4,416,891	$ 4,233,651	$ 5,905,342

(a) Beginning in 2010 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling.

Description of Properties

United States

Approximately 88 percent of the Company's proved reserves at December 31, 2009 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 2009:

	Development Drilling				
	Beginning Wells In Progress	**Wells Spud**	**Successful Wells**	**Unsuccessful Wells**	**Ending Wells In Progress**
Permian Basin	3	55	48	—	10
Rocky Mountains	2	7	9	—	—
Alaska	2	2	3	—	1
Total United States	7	64	60	—	11

	Exploration/Extension Drilling				
	Beginning Wells In Progress	**Wells Spud**	**Successful Wells**	**Unsuccessful Wells**	**Ending Wells In Progress**
Rocky Mountains	4	1	3	1	1
Onshore Gulf Coast	3	4	3	1	3
Barnett Shale	2	7	7	—	2
Alaska	1	1	—	—	2
Total United States	10	13	13	2	8

The following table summarizes the Company's United States costs incurred by geographic area during 2009:

	Property Acquisition Costs					
	Proved	**Unproved**	**Exploration Costs**	**Development Costs**	**Asset Retirement Obligations**	**Total**
	(in thousands)					
Permian Basin	$ 4,002	$ 7,110	$ 8,981	$ 107,231	$ (1,288)	$ 126,036
Mid-Continent	—	—	451	5,626	(1,417)	4,660
Rocky Mountains	83	1,406	13,647	22,941	22,506	60,583
Gulf of Mexico	—	—	397	(36)	20	381
Onshore Gulf Coast	4,309	61,904	35,179	1,775	(296)	102,871
Barnett Shale	376	10,015	15,975	563	(246)	26,683
Alaska	—	(347)	14,876	98,379 (a)	1,011	113,919
Total United States	$ 8,770	$ 80,088	$ 89,506	$ 236,479	$ 20,290	$ 435,133

(a) Includes $9.7 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. According to the Energy Information Administration, the Spraberry field is the second largest oil field in the United States. 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 continues to complete the majority of its wells in the Wolfcamp formation, at depths ranging from 9,200 feet to 11,300 feet with successful results. The Company believes the Spraberry field offers excellent opportunities to grow 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 2008, the Company initiated a program to test 20-acre infill drilling performance, as part of its announced recovery improvement initiatives. The Company drilled and completed eleven 20-acre wells in 2008 and completed nine additional 20-acre wells in 2009 with encouraging results.

During 2010, the Company is commencing a Spraberry field waterflood project that is located on approximately 7,000 acres within an existing Spraberry unit. Drilling, conversion and facility work should be completed during the first half of 2010 with water injection commencing during the second half of 2010.

The 20-acre well spacing and waterflood initiatives described above are being implemented to increase the Spraberry field recovery percentage in those areas of the field that are expected to be conducive for these undertakings. However, the ultimate incremental recovery rates associated with these initiatives cannot be precisely predicted at this time.

During 2009, the Company drilled 48 wells in the Spraberry field and acquired approximately 32,000 gross acres, bringing its total acreage position to approximately 884,000 gross acres (755,000 net acres). In support of the cost reduction initiatives implemented during 2008, the majority of the Company's 2009 drilling program was limited to wells necessary to hold acreage. As a result of successes realized from the Company's cost reduction initiatives and rising oil prices during the first half of 2009, the Company began increasing its rig count and drilling expenditures during the fourth quarter of 2009, with 12 rigs running in the Spraberry field at the end of the year. The Company plans to increase its rig count throughout 2010, with approximately 425 wells planned for the year. The Company intends to continue to expand its drilling program past 2010, with plans to increase its rig count to 40 rigs by 2012, during which the Company expects to drill approximately 1,000 wells per year. The Company plans to acquire Company-owned rigs to support about 25 percent of the planned 40-rig program.

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 220 wells. The Company owns substantially all of the gathering and processing facilities, primarily through the Satanta plant, which processes its production from the Hugoton field. This ownership allows the Company to control the production, gathering, processing and sale of its Hugoton field 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 program was initiated in 2008 with positive results and the Company is evaluating expanding this project further. To capitalize on these rule changes, future completion designs have been developed along with an optimization plan 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 Btu and 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 and gathering system efficiency.

Rocky Mountains

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 "Picketwire Lateral"). 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's gas in the Raton Basin has an average energy content of 1,003

Btu. The Company owns the majority of the well servicing and fracture stimulation equipment that it utilizes in the Raton field, allowing it to control costs and insure availability. In the Raton field, the Company sells its gas at a Mid-Continent index price, which generally provides higher realized gas prices as compared to the Rockies-based indexes. During December 2009, the Company entered into a ten-year firm transportation contract that commences upon completion of a new 675-mile pipeline spanning from Opal, Wyoming to Malin, Oregon. Upon completion of the pipeline's construction, which is currently anticipated during the first quarter of 2011, the Company will have 75,000 MMBtu per day of throughput capacity under this agreement.

The Company's Raton Basin production volumes averaged 31,046 BOEPD for 2009. Production for 2009 experienced a 6 percent decline as compared to 2008 production. The Company continues to realize the benefits of its cost reduction initiatives in the Raton Basin, decreasing total production costs by 17 percent, as compared to 2008, contributing to a reduction of production costs (excluding production and ad valorem taxes) per BOE to $9.42 for 2009, as compared to $10.71 per BOE for 2008. The Company has been able to maintain relatively stable production, with low rates of decline, through initiatives such as compressor upgrades and optimization of compressor configurations.

The production decline for 2009, as compared to 2008, is due to the small capital investment in the field for 2009. The Company drilled seven development wells in the Raton CBM field in 2009 and completed projects to enhance its gathering and compression facilities in the area.

Onshore Gulf Coast

Drilling in the South Texas area in 2009 was sharply curtailed in support of the Company's cost reduction initiatives. The 2009 drilling activity was primarily focused on delineating the Eagle Ford Shale formation within the Company's existing 310,000 gross acre lease position. Production volumes averaged 12,016 BOEPD in 2009, representing a 5 percent decline from 2008 daily production.

A total of three wells were completed during 2009 in the onshore Gulf Coast area of operations. One Eagle Ford Shale exploration well, the Frederich Gas Unit No. 1, was spud in 2008 and completed as a discovery and brought on production during 2009. Another Eagle Ford Shale well, the Sinor Ranch No. 5, was completed as a discovery during 2009. Additionally, two Eagle Ford wells began drilling and remained in progress on December 31, 2009. The Crawley Gas Unit No.1 was completed as a discovery in early January 2010 and an additional Eagle Ford Shale well was in progress as of December 31, 2009 and is expected to be completed during the first quarter of 2010.

Over 2,000 square miles of 3-D seismic data originally acquired to assess Edwards formation drilling opportunities has been used for identifying and prioritizing Eagle Ford Shale well locations. In addition, the 3-D seismic coverage is being used to generate prioritized Edwards formation drilling. Numerous Edwards formation development well locations remain to be drilled in the previously discovered Moray, Sawfish, Skipjack and Amberjack fields. In addition there are several as yet undrilled exploration prospects. The Company continues to maintain a strong leasehold position in South Texas through lease renewals and acquisitions.

The Company has announced plans to seek a joint venture partner for all or a portion of its Eagle Ford Shale acreage position. The Company expects to receive bids from potential joint venture partners during the second quarter of 2010 and close a transaction by mid-year. There can be no assurance that a joint venture transaction can be consummated on terms acceptable to the Company.

Barnett Shale

During 2009, the Company's production volumes averaged 3,002 BOEPD, representing a 24 percent increase over 2008 daily production. The Company participated in the drilling of four successful exploration and development wells on non-operated properties. Another three non-operated wells were drilled, but were not completed as of December 31, 2009. During 2009, the Company enhanced its Barnett Shale acreage position through leasing and acquisitions and acquired approximately 130 square miles of 3-D seismic data. During 2009, the Company focused on improving operational efficiencies, including completing several compressor and artificial lift optimization projects, completing well workovers and enhancing the capacity of water disposal systems.

The Company's total lease holdings in the Barnett Shale play now approximate 65,000 gross acres, most of which is supported by 3-D seismic data.

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 a 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 an estimated 33 horizontal development and injector wells in December of 2007. During 2008, the Company completed two producing wells, one injection well and one disposal well. The Company commenced production from the Oooguruk development project during the second quarter of 2008. During 2009, development and extension drilling progressed and net production averaged approximately 4,600 Bbls per day for the year. Development drilling is expected to continue throughout 2010 and beyond.

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 the Hansen #1A L1 well, a lateral sidetrack from an existing wellbore, to appraise the resource potential of the unit. The initial unstimulated production test results were encouraging and additional permitting and facilities planning ensued during 2008 to further evaluate the unit's resource potential. During 2009, the Company progressed engineering studies and commenced a workover of the Hansen #1A-L1 well. During 2010, the Company plans to complete the Hansen #1A-L1 workover, fracture stimulate the well, flow test the well, evaluate the production flow rate information from the fractured well test, progress project permitting and develop plans for a second well to further delineate the extent of the unit's resource potential.

International

The Company's international operations are located offshore South Africa and onshore in southern Tunisia.

The following tables summarize the Company's Tunisia exploration/extension and development drilling activities during 2009:

	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Exploration/extension drilling	5	2	—	2	5
Development drilling	—	1	1	—	—
Total	5	3	1	2	5

The following table summarizes the Company's international costs incurred by geographic area during 2009:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
			(in thousands)			
South Africa	$ 65	$ —	$ 623	$ (1,768)	$ 320	$ (760)
Tunisia	—	—	20,092	16,991	318	37,401
Other	—	—	724	—	—	724
Total International	$ 65	$ —	$ 21,439	$ 15,223	$ 638	$ 37,365

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 was shut in at the end of the third quarter of 2008. Over its five-year life, the Sable oil field performed better than expected, recovering approximately 23.6 million gross barrels of oil. During the life of the Sable oil field, the majority of the gas produced in conjunction with the oil production was injected back into the reservoir. The Company had a 40 percent working interest in the oil production from the Sable field.

In 2005, the Company sanctioned the non-operated South Coast Gas development project, which included a 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 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. First production from the South Coast Gas project was achieved in the third quarter of 2007.

A significant portion of the gas reserves associated with the South Coast Gas project are in the Sable field. In the third quarter of 2008, Sable oil production was shut in and operations to convert Sable's gas injection well to a producing well commenced. Gas sales from the Sable gas well were initiated in mid-October 2008 and the other South Coast Gas wells resumed production in late-October. The Sable gas well is the most productive well in the South Coast Gas project.

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 12,740 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 1,240 square kilometers. Since 2004, the Company has conducted seismic data acquisition and exploration drilling over the area. As a result of a seismic data acquisition and exploration drilling program, the Company has 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. Since the second half of 2006, the Company has drilled fourteen wells in the concession, with first production being achieved in late 2007. As of December 2009, gross production from the Cherouq Concession has been approximately 5.9 million barrels.

The Company plans to install an artificial lift system and commence drilling operations in the first half of 2010. The Company had one exploratory well suspended and classified as in progress as of December 31, 2009 on the Jenein Nord permit.

Borj El Khadra Permit and Adam Concession. The Borj El Khadra Permit, including the Adam Concession, covers approximately 3,725 square kilometers. Production from the Adam Concession began in May 2003, for which the Company has a 20 percent and 40 percent working interest on exploitation and exploration activities, respectively. During 2009, the Company continued its exploratory and appraisal activities on the Adam Concession by drilling three wells, of which one was a successful Adam concession development well and two were unsuccessful Borj El Khadra Permit exploratory wells.

The Company plans to drill up to three additional wells in the Adam Concession during 2010. On the Borj El Khadra Permit the Company intends to acquire an additional 850 square kilometers of 3-D seismic data and drill an exploration well. The Company had two Borj El Khadra Permit exploratory wells and one Adam concession extension well suspended and classified as in progress as of December 31, 2009.

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. During 2010, the Company plans to further interpret the seismic data in order to develop existing geological prospects.

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. During 2009, the Company prepared a plan of development to request approval to convert a portion of the existing exploration permit into a production concession. The Company plans to drill up to two additional Anaguid exploration wells during 2010 and had one exploratory well suspended and classified as in progress as of December 31, 2009.

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, 2009, 2008 and 2007. 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 2009, 2008 and 2007. 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, 2009					
	United States			South Africa	Tunisia	Total
	Spraberry Field (a)	Raton Field (a)	Total			
Production information:						
Annual sales volumes:						
Oil (MBbls)	5,836	—	9,113	137	2,384	11,634
NGLs (MBbls)	3,454	—	7,183	—	—	7,183
Gas (MMcf)	15,313	67,991	128,753	9,321	609	138,683
Total (MBOE)	11,842	11,332	37,756	1,690	2,485	41,931
Average daily sales volumes:						
Oil (Bbls)	15,989	—	24,968	375	6,531	31,874
NGLs (Bbls)	9,461	—	19,680	—	—	19,680
Gas (Mcf)	41,954	186,278	352,749	25,538	1,668	379,955
Total (BOE)	32,443	31,046	103,440	4,631	6,809	114,880
Average prices, including hedge results and amortization of deferred VPP revenue:						
Oil (per Bbl)	$ 73.12	$ —	$ 75.60	$ 65.94	$ 60.98	$ 72.49
NGL (per Bbl)	$ 25.91	$ —	$ 29.76	$ —	$ —	$ 29.76
Gas (per Mcf)	$ 2.84	$ 3.26	$ 3.88	$ 5.17	$ 8.14	$ 3.99
Revenue (per BOE)	$ 47.27	$ 19.59	$ 37.15	$ 33.85	$ 60.49	$ 38.40
Average prices, excluding hedge results and amortization of deferred VPP revenue:						
Oil (per Bbl)	$ 56.25	$ —	$ 55.04	$ 65.94	$ 60.98	$ 56.38
NGL (per Bbl)	$ 25.91	$ —	$ 28.45	$ —	$ —	$ 28.45
Gas (per Mcf)	$ 2.84	$ 3.26	$ 3.32	$ 5.17	$ 8.14	$ 3.47
Revenue (per BOE)	$ 38.96	$ 19.59	$ 30.02	$ 33.85	$ 60.49	$ 31.98
Average costs (per BOE):						
Production costs:						
Lease operating	$ 10.47	$ 5.14	$ 7.39	$ 3.26	$ 7.38	$ 7.22
Third-party transportation charges	—	2.39	0.95	—	1.69	0.96
Net natural gas plant/gathering	(1.23)	1.79	0.27	—	—	0.25
Workover	1.30	0.10	0.55	—	2.58	0.65
Total	$ 10.54	$ 9.42	$ 9.16	$ 3.26	$ 11.65	$ 9.08
Production and ad valorem taxes:						
Ad valorem	$ 2.10	$ 0.39	$ 1.51	$ —	$ —	$ 1.36
Production	2.72	0.12	1.10	—	—	0.99
Total	$ 4.82	$ 0.51	$ 2.61	$ —	$ —	$ 2.35
Depletion expense	$ 8.69	$ 18.19	$ 14.20	$ 38.33	$ 8.77	$ 14.85

(a) The Company does not record the results of its hedging activities at a field level.

PRODUCTION, PRICE AND COST DATA - (Continued)

	Year Ended December 31, 2008					
	United States			South Africa	Tunisia	Total
	Spraberry Field (a)	Raton Field (a)	Total			
Production information:						
Annual sales volumes:						
Oil (MBbls)	5,713	—	7,720	880	2,261	10,861
NGLs (MBbls)	2,981	—	6,971	—	—	6,971
Gas (MMcf)	14,069	72,386	134,248	3,745	866	138,859
Total (MBOE)	11,038	12,064	37,065	1,504	2,406	40,975
Average daily sales volumes:						
Oil (Bbls)	15,612	—	21,091	2,405	6,178	29,674
NGLs (Bbls)	8,141	—	19,048	—	—	19,048
Gas (Mcf)	38,440	197,775	366,796	10,232	2,367	379,395
Total (BOE)	30,161	32,963	101,271	4,110	6,573	111,954
Average prices, including hedge results and amortization of deferred VPP revenue:						
Oil (per Bbl)	$ 117.10	$ —	$ 65.74	$ 110.21	$ 90.64	$ 74.53
NGL (per Bbl)	$ 46.49	$ —	$ 51.31	$ —	$ —	$ 51.31
Gas (per Mcf)	$ 6.33	$ 7.16	$ 7.66	$ 5.83	$ 12.04	$ 7.64
Revenue (per BOE)	$ 81.24	$ 42.95	$ 51.08	$ 79.00	$ 89.53	$ 54.36
Average prices, excluding hedge results and amortization of deferred VPP revenue:						
Oil (per Bbl)	$ 98.88	$ —	$ 95.82	$ 110.21	$ 90.64	$ 95.91
NGL (per Bbl)	$ 46.49	$ —	$ 51.56	$ —	$ —	$ 51.56
Gas (per Mcf)	$ 6.33	$ 7.16	$ 7.39	$ 5.83	$ 12.04	$ 7.37
Revenue (per BOE)	$ 71.81	$ 42.95	$ 56.41	$ 79.00	$ 89.53	$ 59.18
Average costs (per BOE):						
Production costs:						
Lease operating	$ 12.57	$ 5.16	$ 7.66	$ 25.98	$ 6.26	$ 8.26
Third-party transportation charges	—	2.56	1.06	—	1.93	1.07
Net natural gas plant/gathering	(2.73)	2.90	0.16	—	—	0.15
Workover	2.61	0.09	0.93	—	—	0.84
Total	$ 12.45	$ 10.71	$ 9.81	$ 25.98	$ 8.19	$ 10.32
Production and ad valorem taxes:						
Ad valorem	$ 2.31	$ 0.81	$ 1.58	$ —	$ —	$ 1.43
Production	5.05	1.11	2.86	—	—	2.58
Total	$ 7.36	$ 1.92	$ 4.44	$ —	$ —	$ 4.01
Depletion expense	$ 7.61	$ 12.90	$ 11.30	$ 18.37	$ 5.96	$ 11.25

(a) The Company does not record the results of its hedging activities at a field level.

PRODUCTION, PRICE AND COST DATA - (Continued)

	Year Ended December 31, 2007					
	United States			South Africa	Tunisia	Total
	Spraberry Field (a)	Raton Field (a)	Total			
Production information:						
Annual sales volumes:						
Oil (MBbls)	4,571	—	6,374	979	1,403	8,756
NGLs (MBbls)	3,174	—	6,760	—	—	6,760
Gas (MMcf)	11,783	62,083	113,447	1,037	917	115,401
Total (MBOE)	9,709	10,347	32,041	1,151	1,557	34,749
Average daily sales volumes:						
Oil (Bbls)	12,523	—	17,462	2,681	3,845	23,988
NGLs (Bbls)	8,697	—	18,520	—	—	18,520
Gas (Mcf)	32,282	170,091	310,815	2,840	2,513	316,168
Total (BOE)	26,600	28,349	87,785	3,154	4,264	95,203
Average prices, including hedge results and amortization of deferred VPP revenue:						
Oil (per Bbl)	$ 95.72	$ —	$ 63.25	$ 76.36	$ 70.04	$ 65.80
NGL (per Bbl)	$ 38.33	$ —	$ 41.59	$ —	$ —	$ 41.59
Gas (per Mcf)	$ 6.00	$ 6.06	$ 7.25	$ 6.76	$ 8.77	$ 7.26
Revenue (per BOE)	$ 64.88	$ 36.34	$ 47.04	$ 70.98	$ 68.33	$ 48.79
Average prices, excluding hedge results and amortization of deferred VPP revenue:						
Oil (per Bbl)	$ 71.73	$ —	$ 70.16	$ 76.72	$ 70.04	$ 70.88
NGL (per Bbl)	$ 38.33	$ —	$ 41.59	$ —	$ —	$ 41.59
Gas (per Mcf)	$ 4.89	$ 6.06	$ 6.00	$ 6.76	$ 8.77	$ 6.03
Revenue (per BOE)	$ 52.23	$ 36.34	$ 43.98	$ 71.29	$ 68.33	$ 45.97
Average costs (per BOE):						
Production costs:						
Lease operating	$ 10.35	$ 4.49	$ 6.31	$ 22.43	$ 3.46	$ 6.71
Third-party transportation charges	—	2.53	1.00	—	1.57	0.99
Net natural gas plant/gathering	(2.53)	2.04	0.16	—	—	0.16
Workover	1.62	0.18	0.75	—	0.11	0.69
Total	$ 9.44	$ 9.24	$ 8.22	$ 22.43	$ 5.14	$ 8.55
Production and ad valorem taxes:						
Ad valorem	$ 2.06	$ 0.55	$ 1.36	$ —	$ —	$ 1.25
Production	4.02	0.69	2.16	—	—	2.00
Total	$ 6.08	$ 1.24	$ 3.52	$ —	$ —	$ 3.25
Depletion expense	$ 5.80	$ 12.46	$ 10.08	$ 12.07	$ 5.01	$ 9.92

(a) The Company does not record the results of its hedging activities at a field level.

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, 2009, 2008 and 2007:

PRODUCTIVE WELLS (a)

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
As of December 31, 2009:						
United States	5,332	5,021	10,353	4,566	4,604	9,170
South Africa	—	6	6	—	3	3
Tunisia	29	—	29	9	—	9
Total	5,361	5,027	10,388	4,575	4,607	9,182
As of December 31, 2008:						
United States	5,374	4,988	10,362	4,561	4,685	9,246
South Africa	—	6	6	—	3	3
Tunisia	28	—	28	8	—	8
Total	5,402	4,994	10,396	4,569	4,688	9,257
As of December 31, 2007:						
United States	5,134	4,774	9,908	4,255	4,477	8,732
South Africa	3	5	8	1	2	3
Tunisia	13	—	13	3	—	3
Total	5,150	4,779	9,929	4,259	4,479	8,738

(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, 2009, the Company owned interests in three 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, 2009:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty Acreage
	Gross Acres	Net Acres	Gross Acres	Net Acres	
United States:					
Onshore	1,478,019	1,266,583	1,179,195	900,350	304,442
Offshore	5,760	2,880	—	—	5,000
	1,483,779	1,269,463	1,179,195	900,350	309,442
South Africa	119,579	53,281	3,508,421	1,578,790	—
Tunisia	287,540	80,044	2,860,487	1,569,116	—
Total	1,890,898	1,402,788	7,548,103	4,048,256	309,442

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2009:

	Acres Expiring (a)	
	Gross	Net
2010 (b)	1,470,699	885,046
2011	991,447	494,775
2012	259,037	229,693
2013	164,247	146,539
2014	65,557	57,177
Thereafter	4,597,116	2,235,026
Total	7,548,103	4,048,256

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

(b) All acres subject to expiration during 2010 are in North America and Tunisia. The Company may extend the leases prior to their expiration based upon 2010 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 2009, 2008 and 2007. 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,		
	2009	2008	2007	2009	2008	2007
United States:						
Productive wells:						
Development	60	526	602	58	504	581
Exploratory	13	56	41	7	46	33
Dry holes:						
Development	—	7	2	—	7	2
Exploratory	2	17	5	2	9	3
	75	606	650	67	566	619
Canada:						
Productive wells:						
Development	—	—	1	—	—	1
Exploratory	—	—	7	—	—	5
Dry holes:						
Development	—	—	1	—	—	—
Exploratory	—	—	6	—	—	5
	—	—	15	—	—	11
South Africa:						
Productive wells:						
Development	—	—	3	—	—	1
Exploratory	—	—	—	—	—	—
	—	—	3	—	—	1
Tunisia:						
Productive wells:						
Development	1	—	—	—	—	—
Exploratory	—	6	12	—	3	8
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	2	2	4	1	1	3
	3	8	16	1	4	11
West Africa:						
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	—	—	1	—	—	—
	—	—	1	—	—	—
Total	78	614	685	68	570	642
Success ratio (a)	95%	96%	97%	96%	97%	98%

(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, 2009:

	Gross Wells	Net Wells
United States:		
Development	11	10
Exploratory	8	7
	19	17
Tunisia:		
Exploratory	5	3
Total	24	20

Item 3. Legal Proceedings

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

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

The Company did not submit any matters to a vote of security holders during the fourth quarter of 2009.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is listed and traded on the NYSE under the symbol "PXD." The Board declared dividends to the holders of the Company's common stock of $.08 per share and $.30 per share during the years ended December 31, 2009 and 2008, respectively.

The following table sets forth quarterly high and low prices of the Company's common stock and dividends declared per share for the years ended December 31, 2009 and 2008:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2009			
Fourth quarter	$ 50.00	$ 33.49	$ —
Third quarter	$ 36.74	$ 21.78	$ 0.04
Second quarter	$ 30.56	$ 15.67	$ —
First quarter	$ 20.44	$ 11.88	$ 0.04
Year ended December 31, 2008			
Fourth quarter	$ 52.27	$ 14.03	$ —
Third quarter	$ 82.21	$ 46.24	$ 0.16
Second quarter	$ 82.16	$ 48.49	$ —
First quarter	$ 50.00	$ 36.37	$ 0.14

On February 23, 2010, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $46.18 per share.

As of February 23, 2010, the Company's common stock was held by approximately 22,000 holders of record.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's purchases of treasury stock during the three months ended December 31, 2009:

Period	Total Number of Shares (or Units) Purchased (a)	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs
October 2009	1,584	$ 36.29	—	
November 2009	1,183	$ 41.19	—	
December 2009	34	$ 41.25	—	
Total	2,801	$ 38.42	—	$ 355,789,018

(a) Consists of shares withheld to satisfy tax withholding on employees' share-based awards.

During 2007, the Board approved a share repurchase program authorizing the purchase of up to $750 million of the Company's common stock. During 2009, 2008 and 2007, the Company purchased $16.2 million, $165.2 million and $212.8 million, respectively, of common stock pursuant to the 2007 program.

Item 6. Selected Financial Data

The following selected consolidated financial data as of and for each of the five years ended December 31, 2009 for the Company should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31, (a)				
	2009	2008	2007	2006	2005
	(in millions, except per share data)				
Statements of Operations Data:					
Oil and gas revenues (b)	$ 1,610.0	$ 2,227.6	$ 1,695.3	$ 1,391.7	$ 1,299.2
Total revenues	$ 1,711.5	$ 2,284.8	$ 1,785.0	$ 1,432.8	$ 1,380.6
Total costs and expenses (c)	$ 1,892.0	$ 1,848.8	$ 1,450.0	$ 1,179.1	$ 1,075.8
Income (loss) from continuing operations	$ (132.3)	$ 234.9	$ 229.1	$ 125.0	$ 165.0
Income (loss) from discontinued operations, net of tax (d)	$ 90.1	$ (3.3)	$ 143.2	$ 612.5	$ 367.9
Net income (loss) attributable to common stockholders	$ (52.1)	$ 210.0	$ 372.7	$ 739.7	$ 534.6
Income (loss) from continuing operations per share (e):					
Basic	$ (1.25)	$ 1.79	$ 1.86	$ 0.93	$ 1.17
Diluted	$ (1.25)	$ 1.79	$ 1.85	$ 0.91	$ 1.14
Net income (loss) attributable to common stockholders per share (e):					
Basic	$ (0.46)	$ 1.76	$ 3.05	$ 5.85	$ 3.85
Diluted	$ (0.46)	$ 1.76	$ 3.04	$ 5.75	$ 3.76
Dividends declared per share	$ 0.08	$ 0.30	$ 0.27	$ 0.25	$ 0.22
Balance Sheet Data (as of December 31):					
Total assets	$ 8,867.3	$ 9,161.8	$ 8,617.0	$ 7,355.4	$ 7,329.2
Long-term obligations	$ 4,653.0	$ 4,787.2	$ 4,568.1	$ 3,469.4	$ 4,069.5
Total stockholders' equity	$ 3,643.0	$ 3,679.6	$ 3,054.7	$ 2,999.0	$ 2,226.4

(a) Certain amounts for periods prior to January 1, 2009, have been reclassified to reflect the results of operations of certain assets disposed of during 2009 as discontinued operations, rather than as a component of continuing operations (see Notes B and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional discussion) and to conform to the current year presentation.

(b) The Company's oil and gas revenues for 2009, as compared to those of 2008, declined by $617.6 million (or 28 percent) due to declines in commodity prices, partially offset by a two percent increase in sales volumes. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for discussions about oil and gas revenues and factors impacting the comparability of such revenues.

(c) On January 31, 2009, the Company discontinued hedge accounting for its derivative contracts and began using the mark-to-market ("MTM") method of accounting for derivatives. Under the MTM method of accounting, the Company recognized $195.6 million of derivative losses, net in its total costs and expenses of 2009, including $191.5 million of noncash MTM losses. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Notes B and J of Notes to Consolidated Financial Statements included in "Item 8 Financial Statements and Supplementary Data" for information about the Company's derivative contracts and associated accounting methods.

(d) During 2009, the Company recorded $119.3 million of pretax income for the recovery of excess royalties paid on oil and gas production from its deepwater Gulf of Mexico properties during the period from January 1, 2003 through December 31, 2005, and a $17.5 million pretax gain, primarily from the sale of substantially all of its Gulf of Mexico shelf properties. The Company's Gulf of Mexico shelf and deepwater properties were sold effective July 1, 2009 and January 1, 2006, respectively. The results of operations of these properties, and certain other properties sold during the periods presented are classified as discontinued operations in accordance with GAAP. See Notes B and V of Notes to Consolidated Financial Statements included in "Item 8 Financial Statements and Supplementary Data" for more information about the Company's discontinued operations.

(e) Income from continuing operations per share and net income attributable to common stockholders per share amounts have been restated for the January 1, 2009 adoption of FASB Staff Position EITF 03-6-1 ("FSP EITF 03-6-1") to exclude the earnings of participating securities in the determination of net income (loss) per share. See Notes B and Q of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional discussion about this change in GAAP.

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

Financial and Operating Performance

Pioneer's financial and operating performance for 2009 included the following highlights:

- Earnings attributable to common stockholders was a net loss of $52.1 million ($.46 per diluted share), as compared to net income attributable to common stockholders of $210.0 million ($1.76 per diluted share) in 2008. The decrease in earnings attributable to common stockholders is primarily due to:
  - A $617.6 million pretax decline in oil and gas revenues as a result of commodity price declines, partially offset by an increase in sales volumes;
  - A $185.4 million pretax increase in net derivative losses, primarily due to rising oil and NGL prices since the Company's January 31, 2009 change from hedge accounting to the mark-to market ("MTM") accounting method; and
  - A $161.8 million pretax increase in depreciation, depletion and amortization ("DD&A") expense, primarily due to (i) negative price revisions resulting from lower commodity prices during 2009 as compared to 2008 and (ii) negative reserve price revisions in the fourth quarter of 2009 associated with the SEC's new reserve reporting rules; partially offset by:
  - A $108.3 million decrease in pretax oil and gas production costs and production and ad valorem taxes, primarily due to successes realized from the Company's cost reduction initiatives and commodity price declines, respectively;
  - A $93.3 million increase in after-tax income from discontinued operations, primarily due to $119.3 million of pretax income recognized for the recovery of excess deepwater Gulf of Mexico royalties paid during 2003 through 2005 and a $17.5 million pretax gain from the divestiture of substantially all of the Company's Gulf of Mexico shelf properties during 2009; and
  - A $76.4 million increase in pretax Alaskan Petroleum Production Tax credit dispositions.
- Daily sales volumes from continuing operations increased on a per BOE basis by three percent to 115 MBOEPD during 2009, as compared to 112 MBOEPD during 2008. Approximately 1,100 BOEPD of 2009 annual production was lost due to unplanned third-party pipeline repairs in Alaska and the Mid-Continent area and to longer-than-anticipated gas-to-liquids plant maintenance shutdowns in South Africa.
- Average reported oil, NGL and gas prices from continuing operations decreased during 2009 to $72.49 per Bbl, $29.76 per Bbl and $3.99 per Mcf, respectively, as compared to respective prices of $74.53 per Bbl, $51.31 per Bbl and $7.64 per Mcf during 2008.
- Average oil and gas production costs and ad valorem and production taxes per BOE from continuing operations decreased during 2009 to $9.08 and $2.35, respectively, as compared to respective per BOE costs of $10.32 and $4.01 during 2008, primarily as a result of cost reduction initiatives and commodity price declines.
- Net cash provided by operating activities decreased by $490.8 million to $543.1 million for 2009, as compared to $1.0 billion in 2008, primarily due to the decrease in oil and gas revenue.
- Long-term debt was reduced by $138.2 million during 2009.
- Pioneer Southwest issued 3.1 million common units during 2009 for net proceeds of $61.0 million. The net proceeds from the issuance of common units were used to reduce Pioneer Southwest's credit facility indebtedness.
- The Company issued $450 million of 7.5% Senior Notes due 2020 during November 2009 and used the net proceeds to reduce credit facility indebtedness.

Significant Events

Commodity prices. Beginning in the second half of 2008 and continuing throughout 2009, the United States and other industrialized countries experienced a significant economic slowdown, which led to a substantial decline in worldwide energy demand. During this same time period, North American gas supply was increasing as a result of the rise in domestic unconventional gas production. The combination of lower energy demand due to the economic slowdown and higher North American gas supply resulted in significant declines in prices for oil, NGL and gas. While oil and NGL prices started to steadily improve beginning in the second quarter of 2009, gas prices remained volatile throughout 2009 due to high storage levels and increasing gas supply. The outlook for a worldwide economic recovery in 2010 remains uncertain and therefore, the timing of a recovery in worldwide demand for energy is difficult to predict. As a result, it is likely that commodity prices during 2010 will continue to be volatile.

Although the Company has entered into derivative contracts on a large portion of its production volumes through 2012, a sustained lower commodity price environment would result in lower realized prices for unprotected volumes and reduce the prices at which the Company could enter into derivative contracts on additional volumes in the future. As a result, the Company's cash flows would be reduced for affected periods. Significant or extended price declines could also adversely affect the amount of oil, NGL and gas that the Company can produce economically. The duration, timing and magnitude of any period of lower commodity prices cannot be predicted. A sustained decline in commodity prices could result in a shortfall in expected cash flows, which could negatively affect the Company's liquidity, financial position and future results of operations.

As of December 31, 2009, the Company had $27.4 million of cash on hand and $1.2 billion of liquidity under its credit facility that matures in 2012. As of December 31, 2009, the Company also had $331.7 million of net accounts receivable and was a party to derivative financial instruments, of which approximately $92.3 million represented assets. Management is closely monitoring the credit standings of its customers; counterparties, including its banks; derivative counterparties and purchasers of the commodities the Company produces and sells.

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Notes F and J, respectively of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's credit facility and derivative contracts.

Cost reduction initiatives. During the second half of 2008, the Company increased its emphasis on reducing capital spending, operating costs and administrative expenses to support its goal of delivering net cash flow from operating activities in excess of capital requirements in 2009 and to enhance and preserve financial flexibility. These initiatives included minimizing drilling activities until margins improved as a result of (i) commodity prices increasing and/or (ii) well cost reductions. As a result, the Company significantly reduced its 2009 rig activity and has realized and continues to pursue reductions in operating expenses and well costs to align costs with a lower commodity price environment. Rigs were terminated or stacked in the Spraberry, Raton, Edwards Trend and Barnett Shale areas and in Tunisia. Since the third quarter of 2008, when drilling and completion costs peaked, the Company has achieved a reduction of approximately 30 percent in the cost of drilling and completing a well in the Spraberry field. The Company's asset teams have also reduced 2009 lease operating expense per BOE from continuing operations by 13 percent during 2009, as compared to 2008. The cost savings reflect reductions in electricity, water disposal and compression rental costs and expanded use of Pioneer's internal well services in the Spraberry field.

During 2009, the Company's capital costs (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs) were $312.9 million, as compared to $1.2 billion during 2008, representing a 74 percent decrease. As a result of the successes realized from the aforementioned cost reduction initiatives and increases in 2009 oil prices, the Company implemented a plan to resume oil- and liquids-rich-gas-focused drilling activities during 2010 and has preliminarily targeted its 2010 capital budget to be in a range of $800 million to $900 million (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs).

Historically, the Company's capital and operating costs have risen during periods of increased oil, NGL and gas prices. These costs may rise faster than increases in the Company's revenue, thereby negatively impacting the Company's profitability, cash flow and ability to complete development activities as planned.

Sale of assets to Pioneer Southwest. On August 31, 2009, the Company completed a sale of oil and gas properties in the Spraberry field to Pioneer Southwest pursuant to a Purchase and Sale Agreement having an effective date of July 1, 2009. Associated therewith, Pioneer received $168.2 million of cash, including customary closing adjustments, and transferred net obligations associated with certain commodity price derivative positions and certain other liabilities to Pioneer Southwest. Proceeds were used to reduce Pioneer's credit facility indebtedness and Pioneer Southwest funded the purchase with cash on hand and borrowings under its credit facility.

Pioneer Southwest equity offering. On November 16, 2009, Pioneer Southwest completed a public offering of 3,105,000 common units representing limited partner interests (the "Equity Offering"). Net proceeds from the Equity Offering of $61.0 million were used to reduce Pioneer Southwest's credit facility borrowings. Following the Equity Offering, Pioneer owns a 61.9 percent limited partner interest in Pioneer Southwest.

Senior note issuance. In November 2009, the Company issued $450 million of 7.5% Senior Notes due 2020 for net proceeds of $438.6 million. The net proceeds were used to reduce the Company's credit facility indebtedness.

Modernization of oil and gas reporting. During 2009, the SEC issued the Reserve Ruling and the FASB issued ASU 2010-03. The Reserve Ruling and the ASU 2010-03 are effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. The key provisions of the Reserve Ruling and ASU 2010-03, which impact the Company's disclosures and consolidated financial statements, are as follows:

- Amending the definition of proved oil and gas reserves to require the use of an average of the first-day-of-the-month commodity prices during the 12-month period ending on the balance sheet date rather than the period-end commodity prices;
- Adding to and amending other definitions used in estimating proved oil and gas reserves, such as "reliable technology" and "reasonable certainty";
- Broadening the types of technology that a reporter may use to establish reserves estimates and categories; and
- Changing disclosure requirements and providing formats for tabular reserve disclosures.

See "Item 2. Properties," above "—Results of Operations – Depletion, depreciation and amortization expense" below and supplementary disclosures in "Item 8 Financial Statements and Supplementary Data" for associated disclosures and information about how the adoption of the Reserve Ruling and ASU 2010-03 affected the Company.

First Quarter 2010 Outlook

Based on current estimates, the Company expects that first quarter 2010 production will average 112,000 to 117,000 BOEPD, reflecting increased 2010 drilling activity, the expiration of the VPP obligation in the Hugoton field, the return of production in South Africa after the fourth quarter 2009 maintenance shutdown and the planned oil lifting schedule for Tunisia.

First quarter production costs from continuing operations (including production and ad valorem taxes and transportation costs) are expected to average $11.50 to $13.50 per BOE, based on current NYMEX strip prices for oil and gas. DD&A expense is expected to average $14.50 to $16.00 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $25 million to $35 million, primarily related to exploration wells, including related acreage costs, and seismic and personnel costs. General and administrative expense is expected to be $35 million to $39 million. Interest expense is expected to be $45 million to $48 million, and other expense is expected to be $12 million to $17 million. Accretion of discount on asset retirement obligations from continuing operations is expected to be $2 million to $4 million.

Noncontrolling interest in consolidated subsidiaries' net income, excluding noncash MTM adjustments, is expected to be $9 million to $12 million, primarily reflecting the public ownership in Pioneer Southwest.

The Company's first quarter effective income tax rate is expected to range from 40 percent to 50 percent, based on current capital spending plans, higher tax rates in Tunisia and no significant MTM changes in the Company's derivative position. Cash income taxes are expected to be $10 million to $15 million and are primarily related to Tunisia.

Acquisitions

During 2009, the Company spent $88.9 million to acquire proved and unproved properties. The acquisitions primarily increased the Company's unproved acreage positions in the South Texas Eagle Ford Shale play. During 2008, the Company spent $137.6 million to acquire proved and unproved properties. The acquisitions primarily added proved reserves and increased the Company's acreage positions in the Spraberry field, Edwards Trend and Barnett Shale play. During 2007, the Company spent $536.7 million to acquire proved and unproved properties. The acquisitions primarily added proved reserves and increased the Company's acreage positions in the Spraberry field, Raton field and Barnett Shale play.

Divestitures

Mississippi and Gulf of Mexico Shelf. In June and August 2009, the Company sold its Mississippi and shelf properties in the Gulf of Mexico, respectively, for aggregate net proceeds of $23.6 million, resulting in a pretax gain of $17.5 million. The historical results of these assets and the related gain on disposition are reported as discontinued operations.

Canada. In November 2007, the Company sold its Canadian subsidiaries for $525.7 million, resulting in a gain of $101.3 million. The historical results of these assets and the related gain on disposition are reported as discontinued operations.

Results of Operations

Oil and gas revenues. Oil and gas revenues totaled $1.6 billion, $2.2 billion and $1.7 billion during 2009, 2008 and 2007, respectively. The revenue decrease during 2009, as compared to 2008, is reflective of decreases in the Company's revenues in all geographic areas. The decrease in 2009 oil and gas revenues relative to 2008 was due to commodity price declines during 2009 and a reduction in 2009 drilling due to cost reduction initiatives, as described above in "Significant Events." In the United States, the Company's 2009 average reported NGL and gas prices declined 42 percent and 49 percent, respectively, as compared to 2008. These 2009 declines were partially offset by a 15 percent increase in the 2009 average reported oil price and a two percent increase in 2009 average daily sales volumes on a BOE basis as compared to 2008. In South Africa, the Company's average reported oil and gas prices in 2009 decreased 40 percent and 11 percent, respectively, partially offset by a 13 percent increase in average daily sales volumes on a BOE basis as compared to 2008. In Tunisia, the Company's average reported oil and gas prices in 2009 decreased 33 percent and 32 percent, respectively, partially offset by a four percent increase in average daily sales volumes on a BOE basis as compared to 2008.

The revenue increase during 2008, as compared to 2007, is reflective of increases in the Company's revenues in all geographic areas. The increase in United States revenues was primarily due to an increase in average daily sales volumes resulting from successful drilling programs, core area acquisitions and reductions in scheduled VPP deliveries, combined with a 23 percent increase in average reported NGL prices, a four percent increase in average reported oil prices and a six percent increase in average reported gas prices. South African revenues increased due to an increase in average daily sales volumes realized from a full year of sales from the portion of the wells in the South Coast Gas project that commenced gas production during the fourth quarter of 2007, and a 44 percent increase in average reported oil price, partially offset by a 14 percent decrease in average reported gas price. The increase in Tunisian revenues resulted from an increase in average daily sales volumes from successful drilling efforts, a 37 percent increase in average reported gas price and a 29 percent increase in average reported oil price.

The following table provides average daily sales volumes from continuing operations by geographic area and in total for 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Oil (Bbls):			
United States	24,968	21,091	17,462
South Africa	375	2,405	2,681
Tunisia	6,531	6,178	3,845
Worldwide	31,874	29,674	23,988
NGLs (Bbls):			
United States	19,680	19,048	18,520
Gas (Mcf):			
United States	352,749	366,796	310,815
South Africa	25,538	10,232	2,840
Tunisia	1,668	2,367	2,513
Worldwide	379,955	379,395	316,168
Total (BOE):			
United States	103,440	101,271	87,785
South Africa	4,631	4,110	3,154
Tunisia	6,809	6,573	4,264
Worldwide	114,880	111,954	95,203

On a BOE basis, average daily production for 2009, as compared to 2008, increased by two percent in the United States, 13 percent in South Africa and four percent in Tunisia. Average daily production for 2008, as compared to 2007, increased by 15 percent in the United States, 30 percent in South Africa and 54 percent in Tunisia.

During the year ended December 31, 2009, oil and gas volumes delivered under the Company's VPP agreements decreased by seven percent, as compared to 2008. During the year ended December 31, 2008, oil and gas volumes delivered under the Company's VPP agreements decreased by 12 percent, as compared to 2007.

The following table provides average daily sales volumes from discontinued operations by geographic area and in total during 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Oil (Bbls):			
United States	554	953	1,181
Canada	—	—	267
Worldwide	554	953	1,448
NGLs (Bbls):			
United States	29	35	33
Canada	—	—	371
Worldwide	29	35	404
Gas (Mcf):			
United States	1,899	3,428	5,603
Canada	—	—	44,645
Worldwide	1,899	3,428	50,248
Total (BOE):			
United States	900	1,559	2,148
Canada	—	—	8,080
Worldwide	900	1,559	10,228

The following table provides average reported prices from continuing operations, including recorded commodity hedge gains and losses and the amortization of VPP deferred revenue, and average realized prices from continuing operations, excluding recorded commodity hedge gains and losses and the amortization of VPP deferred revenue, by geographic area and in total for 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Average reported prices:			
Oil (per Bbl):			
United States	$ 75.60	$ 65.74	$ 63.25
South Africa	$ 65.94	$ 110.21	$ 76.36
Tunisia	$ 60.98	$ 90.64	$ 70.04
Worldwide	$ 72.49	$ 74.53	$ 65.80
NGL (per Bbl):			
United States	$ 29.76	$ 51.31	$ 41.59
Gas (per Mcf):			
United States	$ 3.88	$ 7.66	$ 7.25
South Africa	$ 5.17	$ 5.83	$ 6.76
Tunisia	$ 8.14	$ 12.04	$ 8.77
Worldwide	$ 3.99	$ 7.64	$ 7.26
Total (per BOE):			
United States	$ 37.15	$ 51.08	$ 47.04
South Africa	$ 33.85	$ 79.00	$ 70.98
Tunisia	$ 60.49	$ 89.53	$ 68.33
Worldwide	$ 38.40	$ 54.36	$ 48.79
Average realized prices:			
Oil (per Bbl):			
United States	$ 55.04	$ 95.82	$ 70.16
South Africa	$ 65.94	$ 110.21	$ 76.72
Tunisia	$ 60.98	$ 90.64	$ 70.04
Worldwide	$ 56.38	$ 95.91	$ 70.88
NGL (per Bbl):			
United States	$ 28.45	$ 51.56	$ 41.59
Gas (per Mcf):			
United States	$ 3.32	$ 7.39	$ 6.00
South Africa	$ 5.17	$ 5.83	$ 6.76
Tunisia	$ 8.14	$ 12.04	$ 8.77
Worldwide	$ 3.47	$ 7.37	$ 6.03
Total (per BOE):			
United States	$ 30.02	$ 56.41	$ 43.98
South Africa	$ 33.85	$ 79.00	$ 71.29
Tunisia	$ 60.49	$ 89.53	$ 68.33
Worldwide	$ 31.98	$ 59.18	$ 45.97

Derivative activities. The Company utilizes commodity swap contracts, collar contracts and collar contracts with short puts 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. Prior to February 1, 2009, the Company accounted for substantially all of its derivative activity using hedge accounting, which requires that the effective portions of changes in the fair values of the Company's commodity price hedges be deferred as increases or decreases to accumulated other comprehensive income – deferred hedge gains, net of tax ("AOCI – Hedging"), in the stockholders' equity section of the Company's consolidated balance sheets, until the underlying hedged transaction occurs. Consequently, changes in the effective portions of commodity price hedges added volatility to the Company's reported stockholders' equity until the hedge derivative either matured or was terminated. Effective February 1, 2009, the Company discontinued hedge accounting on all of its existing derivative instruments and since that date has accounted for its derivative instruments using the MTM accounting method. Therefore, the Company now recognizes changes in the fair values of its derivative contracts as gains or losses in the earnings of the period in which they occur. During 2009, the Company transferred $121.1 million of previously deferred commodity hedge gains from AOCI – Hedging to oil and gas revenues and, during 2008 and 2007, transferred $355.6 million and $83.4 million, respectively, of previously deferred commodity hedge losses from AOCI – Hedging to oil and gas revenues. During 2009 and 2008, the Company's non-hedge derivative contracts resulted in net derivative losses of $195.6 million and $9.6 million, respectively. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information concerning the Company's open and terminated derivative positions at December 31, 2009, descriptions of the Company's commodity derivatives and scheduled amortization of net deferred gains and losses on discontinued commodity hedges that will be recognized as increases or decreases to future oil and gas revenues. Also see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional disclosures about the Company's commodity related derivative financial instruments.

The following table provides the net effect of transfers of previously deferred oil, NGL and gas price hedges from AOCI – Hedging to oil, NGL and gas revenues from continuing operations for the years ending December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	**2008**	**2007**
Increase (decrease) to oil revenue from hedging activity	$ 88,873	$ (336,249)	$ (154,071)
Increase (decrease) to NGL revenue from hedging activity	9,402	(1,781)	—
Increase (decrease) to gas revenue from hedging activity	22,791	(17,533)	70,624
Total	$ 121,066	$ (355,563)	$ (83,447)

Deferred revenue. During 2009, 2008 and 2007, the Company's recognition of previously deferred VPP revenue increased oil and gas revenues from continuing operations by $147.9 million, $158.1 million and $181.2 million, respectively. The Company's amortization of deferred VPP revenue is scheduled to increase 2010 oil and gas revenues by $90.2 million. See Note T of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's VPP agreements.

Interest and other income. The Company's interest and other income from continuing operations totaled $102.3 million, $57.6 million and $91.9 million during 2009, 2008 and 2007, respectively. The $44.7 million increase during 2009, as compared to 2008, is primarily attributable to (i) a $76.4 million increase in Alaskan Petroleum Production Tax ("PPT") credit dispositions, partially offset by (ii) a $20.5 million 2008 gain on early extinguishment of debt and (iii) a $7.2 million decrease in foreign exchange gains. The $34.3 million decrease during 2008, as compared to 2007, is primarily attributable to (i) a $56.2 million decrease in PPT credit dispositions, partially offset by (ii) the aforementioned gain on early extinguishment of debt.

In 2006, Alaska replaced its severance tax with the PPT for periods beginning after March 31, 2006. In late 2007, Alaska made further changes to the PPT through legislation referred to as "Alaska's Clear and Equitable Share" ("ACES"). The ACES modifications to PPT were effective as of July 1, 2007. Due to the Company's expenditures in Alaska before beginning production, the Company generated PPT-related carryforwards. At December 31, 2009, the Company had $30.3 million of available PPT-related carryforwards that may be monetized in the future. The Company anticipates recognizing further benefits from the PPT-related carryforwards from (i) a reduction in PPT liabilities or (ii) sales of the carryforwards to third parties, if transferable, or reimbursement from the State of Alaska. The Company anticipates that any transfers of PPT-related carryforwards to third parties would be at a discounted value. The amount of discount is currently not known but is not expected to be significant. During January 2010, the Company was reimbursed $14.1 from the State of Alaska for PPT-related carryforwards, which amount will be included in its first quarter 2010 interest and other income.

Loss on disposition of assets. The Company recorded net losses on the disposition of assets of $774 thousand, $381 thousand and $2.2 million in 2009, 2008 and 2007, respectively.

During 2009, the Company recognized a gain on the sale of its Mississippi and substantially all of its Gulf of Mexico shelf properties of $17.5 million. During 2007, the Company recognized a gain on the sale of its Canadian assets of $101.3 million. These gains and the results of operations from the divested net assets are presented as discontinued operations in the Company's accompanying consolidated statements of operations.

The net cash proceeds from asset divestitures during 2009, 2008 and 2007 were used, together with net cash flows provided by operating activities, to fund additions to oil and gas properties, stock repurchase programs and to reduce outstanding indebtedness. See Notes N and V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's asset divestitures and discontinued operations.

Oil and gas production costs. The Company's oil and gas production costs totaled $380.3 million, $422.6 million and $297.0 million during 2009, 2008 and 2007, respectively. In general, lease operating expenses and workover expenses represent the components of oil and gas production costs over which the Company has management control, while third-party transportation charges represent the cost to transport volumes produced to a sales point. Net natural gas plant/gathering charges represent the net costs to gather and process the Company's gas, reduced by net revenues earned from gathering and processing of third party gas in Company-owned facilities.

Total production costs per BOE decreased during 2009 by 12 percent as compared to 2008. During 2008, the Company's oil and gas production costs increased throughout the first nine months of the year, primarily due to inflation of well servicing expense, electricity expense and water hauling costs. As a result of the Company's ongoing cost reduction initiatives, Pioneer realized significant production cost savings during 2009, as compared to 2008, and anticipates continued cost savings in the foreseeable future. The decrease in South Africa production costs is directly attributable to the shut in of the Sable oil field, which had a high fixed-cost component of production costs as compared to the South Coast Gas project, which has significantly lower production costs. The increase in Tunisia production costs is associated with increasing production from the Company's Cherouq concession, which utilizes relatively high-cost rental facilities in its operations. Tunisia production costs are expected to decline in the future with the installation of permanent facilities.

Total production costs per BOE increased during 2008 by 21 percent as compared to 2007 primarily due to increases in lease operating expense. The increase in lease operating expenses is primarily due to (i) fixed production costs associated with first sales from the Alaskan Oooguruk development project, (ii) fixed production costs associated with the Company's South African Sable oil field production, prior to its shut in September 2008, (iii) production operations in the Tunisian Cherouq concession, (iv) unscheduled compressor repairs and maintenance in the Raton field and (v) the aforementioned inflation of field service costs and electricity charges.

The following tables provide the components of the Company's total production costs per BOE and total production costs per BOE by geographic area for 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Lease operating expenses	$ 7.22	$ 8.26	$ 6.71
Third-party transportation charges	0.96	1.07	0.99
Net natural gas plant/gathering charges (credits)	0.25	0.15	0.16
Workover costs	0.65	0.84	0.69
Total production costs	$ 9.08	$ 10.32	$ 8.55

	Year Ended December 31,		
	2009	2008	2007
United States	$ 9.16	$ 9.81	$ 8.22
South Africa	$ 3.26	$ 25.98	$ 22.43
Tunisia	$ 11.65	$ 8.19	$ 5.14
Worldwide	$ 9.08	$ 10.32	$ 8.55

Production and ad valorem taxes. The Company recorded production and ad valorem taxes of $98.4 million during 2009, as compared to $164.4 million and $112.9 million for 2008 and 2007. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, whereas production taxes are based upon current year commodity prices. During 2009, the Company's production taxes per BOE declined 62 percent, reflecting the year-to-year decline in commodity prices, while ad valorem taxes decreased slightly. During 2008, the Company's production taxes increased 29 percent, reflecting the year-to-year increase in commodity prices, and ad valorem taxes increased 14 percent.

The following table provides the Company's production and ad valorem taxes per BOE from continuing operations and total production and ad valorem taxes per BOE from continuing operations for 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Ad valorem	$ 1.36	$ 1.43	$ 1.25
Production	0.99	2.58	2.00
Total ad valorem and production taxes	$ 2.35	$ 4.01	$ 3.25

Depletion, depreciation and amortization expense. The Company's total DD&A expense was $15.54, $11.95 and $10.74 per BOE for 2009, 2008 and 2007, respectively. Depletion expense, the largest component of DD&A expense, was $14.85, $11.25 and $9.92 per BOE during 2009, 2008 and 2007, respectively. During 2009, the increase in per BOE depletion expense was primarily due to (i) losing end-of-life reserves that became uneconomic as a result of commodity price declines since December 31, 2008, (ii) a generally increasing trend through 2008 in the Company's oil and gas properties' cost bases per BOE of proved and proved developed reserves as a result of cost inflation in drilling rig rates and drilling supplies and (iii) the relatively higher depletion rate per BOE associated with production from the Oooguruk development, which began first production in June 2008, and the South African South Coast Gas project, which became fully operational in October 2008.

During 2009, the Company adopted the provisions of the Reserve Ruling and ASU 2010-03. The provisions of the Reserve Ruling and ASU 2010-03, which became effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009, changed the definition of proved oil and gas reserves to require the use of an average of the first-day-of-the-month commodity prices during the 12-month period ending on the balance sheet date rather than the period-end commodity prices; added to and amended certain definitions used in estimating proved oil and gas reserves, such as "reliable technology" and "reasonable certainty;" and broadened the types of technology that an issuer may use to establish reserves estimates and categories. Application of the new pricing provisions of the Reserve Ruling reduced the Company's fourth quarter 2009 end-of-life reserves from what they would have been under the previous definition of proved reserves that used end-of-period pricing, thereby increasing the Company's DD&A expense for the fourth quarter of 2009 by $16.5 million, or $0.39 per BOE for the year ended December 31, 2009. The other provisions of the Reserve Ruling and ASU 2010-03 did not have a material effect on the Company as of and for the period ended December 31, 2009. During 2009, the Company's cost reduction initiatives and a declining trend in drilling costs mitigated the 2009 increase in per BOE depletion expense.

During 2008, the increase in per BOE depletion expense was primarily due to (i) losing end-of-well-life reserves that became uneconomic as a result of lower 2008 year-end commodity prices, (ii) a generally increasing trend in the Company's oil and gas properties' cost bases per BOE of proved and proved developed reserves as a result of cost inflation in drilling rig rates and drilling supplies and (iii) the relatively higher depletion rate per BOE associated with production from the Oooguruk development and South African South Coast Gas projects.

The following table provides depletion expense per BOE from continuing operations by geographic area for 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
United States	$ 14.20	$ 11.30	$ 10.08
South Africa	$ 38.33	$ 18.37	$ 12.07
Tunisia	$ 8.77	$ 5.96	$ 5.01
Worldwide	$ 14.85	$ 11.25	$ 9.92

Impairment of oil and gas properties and other assets. The Company reviews its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. During the year ended December 31, 2009, the Company recognized impairment charges of $21.1 million to reduce the carrying value of the Company's oil and gas properties in the Uinta/Piceance areas. During the year ended December 31, 2008, the Company recognized impairment charges of $104.3 million, including $14.5 million attributable to discontinued operations, to reduce the carrying value of its net assets in the Uinta/Piceance and Mississippi areas. Declines in gas prices and downward adjustments to the economically recoverable resource potential of these properties led to the impairment charges.

During the year ended December 31, 2007, the Company recognized aggregate impairment charges of $26.2 million. The impairment charges in 2007 included $10.3 million to write off the Company's basis in Block H in Equatorial Guinea, $10.2 million related to Block 320 in Nigeria and $5.7 million to reduce the carrying values of certain oil and gas properties located in Louisiana due to poor well performance.

Commodity price declines during the second half of 2008 provided indications that the Company's $310.6 million carrying value of goodwill may have been impaired as of December 31, 2008. The Company assessed the carrying value of goodwill for impairment as of December 31, 2008, March 31, 2009, June 30, 2009 and during the third quarter of 2009 and found it not to be impaired. However, goodwill remains at risk for impairment in future periods if commodity prices decline or if other impairment indicators were to erode. See Note S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's impairment assessments and the primary factors that affect the Company's assessments of goodwill and oil and gas properties for impairment.

Exploration and abandonments expense. The following tables provide the Company's geological and geophysical costs, exploratory dry hole expense and lease abandonments and other exploration expense by geographic area for 2009, 2008 and 2007 (in thousands):

	United States	South Africa	Tunisia	Other	Total
Year ended December 31, 2009					
Geological and geophysical	$ 40,921	$ 623	$ 7,739	$ 721	$ 50,004
Exploratory dry holes	6,872	—	9,867	—	16,739
Leasehold abandonments and other	31,303	—	—	—	31,303
	$ 79,096	$ 623	$ 17,606	$ 721	$ 98,046
Year ended December 31, 2008					
Geological and geophysical	$ 72,146	$ 143	$ 22,499	$ —	$ 94,788
Exploratory dry holes	73,741	—	15,130	—	88,871
Leasehold abandonments and other	43,841	—	—	—	43,841
	$ 189,728	$ 143	$ 37,629	$ —	$ 227,500
Year ended December 31, 2007					
Geological and geophysical	$ 90,751	$ 276	$ 2,812	$ 9,182	$ 103,021
Exploratory dry holes	119,638	—	13,931	13,851	147,420
Leasehold abandonments and other	20,577	—	—	7,639	28,216
	$ 230,966	$ 276	$ 16,743	$ 30,672	$ 278,657

During 2009, the Company's exploration and abandonment expense was primarily attributable to United States and Tunisian geological and geophysical personnel costs, United States and Tunisian dry hole expense and United States unproved property abandonments. The significant components of the Company's 2009 exploratory dry hole provisions and leasehold abandonments expense included (i) $7.8 million of dry hole provisions in the Company's Borj El Khadra permit and Adam concession areas of Tunisia, (ii) $6.9 million of United States dry hole provisions, primarily associated with the write off of suspended well costs and (iii) $29.4 million of United States unproved property abandonments. During 2009, the Company completed and evaluated 17 exploration/extension wells, 13 of which were successfully completed as discoveries.

During 2008, the Company's exploration and abandonment expense was primarily attributable to seismic activity in the Company's Mississippi, South Texas and Tunisia areas, dry hole expense and unproved property abandonments. The significant components of the Company's exploratory dry hole provisions and unproved property abandonments expense included (i) $47.1 million of costs associated with the unsuccessful Lay Creek CBM pilot project, (ii) $12.2 million of costs associated with the unsuccessful Delaware Basin exploration project, (iii) $11.3 million of costs associated with the unsuccessful Sligo exploration well in South Texas and (iv) $41.1 million of U.S. unproved property abandonments. During 2008, the Company completed and evaluated 81 exploration/extension wells, 62 of which were successfully completed as discoveries.

During 2007, significant components of the Company's exploratory dry hole provisions and leasehold abandonments expense included: (i) $72.1 million of suspended well costs written off associated with the discontinuation of the Clipper project in the deepwater Gulf of Mexico due to increasing costs, (ii) $13.8 million of costs associated with the Company's unsuccessful exploratory well on its Block 256 offshore Nigeria, (iii) $50.8 million for costs associated with two unsuccessful exploratory wells in the Company's Alaskan National Petroleum Reserve area and the write-off of the remaining prospect costs in the onshore Alaskan North Slope area and (iv) $13.9 million of Tunisian dry hole provisions and abandonment costs, which primarily related to the write-off of a suspended well drilled in 2003 on the Anaguid permit and an unsuccessful exploratory well in both the Jenein Nord permit and the Borj El Khadra permit. During 2007, the Company's seismic activity primarily related to its resource plays in South Texas and the Rocky Mountains. During 2007, the Company completed and evaluated 76 exploration/extension wells, 60 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense totaled $140.3 million, $141.9 million and $129.7 million during 2009, 2008 and 2007, respectively. The decrease in general and administrative expense during 2009, as compared to 2008, was primarily due to the Company's cost reduction initiatives, partially offset by increases in compensation and occupancy expenses and a decline in general and administrative recoveries primarily related to Tunisia operations. See "—Significant Events" above for information regarding commodity prices and the Company's cost reduction initiatives.

The increase in general and administrative expense during 2008, as compared to 2007, was primarily due to (i) expenses associated with the administration of Pioneer Southwest and (ii) continuing increases in performance-related compensation costs, including the amortization of share-based compensation to officers, directors and employees.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations from continuing operations was $11.0 million, $7.9 million and $6.1 million during 2009, 2008 and 2007, respectively. The increase in accretion of discount on asset retirement obligations during 2009 and 2008 was primarily due to the accretion associated with higher asset retirement obligations as a result of declining commodity prices having the effect of reducing the economic life of the Company's wells, thus accelerating their forecasted abandonment date, plus the accretion attributable to new wells placed on production. See Note L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's asset retirement obligations.

Interest expense. Interest expense was $173.4 million, $166.8 million and $135.3 million during 2009, 2008 and 2007, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2009 was 5.2 percent, as compared to 5.5 percent and 6.5 percent for the years ended December 31, 2008 and 2007, respectively, including the effects of interest rate derivatives.

Effective January 1, 2009, the Company adopted certain provisions of FASB Staff Position No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)," which was primarily codified into Accounting Standards Codification ("ASC") Topic 470 ("ASC Topic 470"). The provisions of ASC Topic 470 resulted in a retrospective adjustment to increase the Company's 2008 interest expense by $13.2 million and increased the Company's 2009 interest expense by $14.4 million.

The $6.6 million increase in interest expense during the year ended December 31, 2009, as compared to 2008, was primarily due to (i) a $9.2 million decrease in capitalized interest related to the Oooguruk project as development wells were placed on production, partially offset by (ii) a $4.8 million decrease in cash interest expense on long-term borrowings.

The $31.5 million increase in interest expense during 2008, as compared to 2007, was primarily due to (i) an $18.2 million increase in interest incurred on senior notes due to an increase in average senior note borrowings outstanding, (ii) a $13.6 million decrease in capitalized interest due to the completion of the South African South Coast Gas project during 2007 and declining capitalized interest on the Oooguruk development project in Alaska and (iii) a $13.2 million increase due to the new provisions of ASC Topic 470, partially offset by (iv) a $12.6 million decrease in interest incurred on the Company's credit facility due to declining interest rates.

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

Hurricane activity, net. The Company recorded net hurricane related activity expenses of $17.3 million, $12.2 million and $61.3 million during 2009, 2008 and 2007, respectively, associated with the Company's East Cameron platform facilities, located on the Gulf of Mexico shelf, that were destroyed during 2005 by Hurricane Rita.

The Company estimates that it will cost approximately $6 million to complete operations to reclaim and abandon the East Cameron platform facilities. Since January 2007, the Company has spent $199.0 million on operations to reclaim and abandon the East Cameron platform facilities. During 2007, the Company commenced legal actions against its insurance carriers regarding certain policy coverage issues. The Company continues to expect that a substantial portion of the loss will be recoverable by insurance. During 2009, the Company received $40.7 million of insurance recoveries associated with the reclamation of the East Cameron facilities. The 2009 East Cameron insurance recoveries reduced a $35.0 million receivable that was included in the Company's consolidated balance sheet as of December 31, 2008. The remaining $5.7 million of 2009 insurance recoveries were credited to net hurricane activity in the Company's accompanying consolidated statement of operations for the year ended December 31, 2009. See Note U of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for specific information regarding the Company's East Cameron platform facilities reclamation and abandonment.

Derivative losses, net. Effective February 1, 2009, the Company discontinued hedge accounting on all existing derivative instruments and since that date has accounted for derivative instruments using the mark-to-market accounting method. Under the mark-to-market accounting method, the Company recognizes changes in the fair values of its derivative contracts as gains or losses in the earnings of the period in which they occur. During the year ended December 31, 2009, the Company's commodity price derivatives increased net derivative losses by $195.6 million, of which amount $191.6 million represented unrealized losses subject to continuing market risk, and $4.0 million represented realized losses. During the years ended December 31, 2008 and 2007, the Company recorded net derivative losses of $10.1 million and $2.1 million, primarily comprised of unrealized losses on derivatives that were not designed as hedges prior to January 31, 2009. The $185.5 million increase in net derivative losses during 2009, as compared to 2008, was primarily due to the Company's discontinuance of hedge accounting as of February 1, 2009 and increases in oil and NGL commodity prices during the last three quarters of 2009. The $8.0 million increase in derivative losses, net during 2008, as compared to 2007, was primarily due to increases in oil prices after non-hedge derivatives were entered into during 2008.

Other expenses. Other expenses were $105.0 million during 2009, as compared to $116.0 million during 2008 and $27.3 million during 2007. The $11.0 million decrease in other expense during 2009, as compared to 2008, is primarily attributable to (i) a $25.8 million decrease in bad debt expense, partially offset by (ii) a $9.1 million increase in idle well servicing operations.

The $88.7 million increase in other expense during 2008, as compared to 2007, is primarily attributable to (i) a $25.0 million increase in bad debt expense, primarily attributable to $19.6 million in bad debt expense related to the bankruptcy of SemGroup, L.P. and certain of its subsidiaries (collectively, "SemGroup"), (ii) a $45.9 million increase in idle and terminated rig related costs, and (iii) a $10.4 million postretirement benefit obligation reduction recorded during 2007.

The Company was a creditor in the bankruptcy of SemGroup, which filed petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code on July 22, 2008 in the U.S. Bankruptcy Court for the District of Delaware. SemGroup purchased condensate from the Company and, at the time of the bankruptcy filings, was indebted to the Company for $29.6 million. The Company believed that it was probable that the collection of the pre-petition claims would not occur for a protracted period of time and that some of its claims may become uncollectible. Consequently, the Company recorded a bad debt expense of $19.6 million during the second half of 2008, which reduced the carrying value of the claims to $10.0 million.

In April 2009, the Company sold all of its pre-petition claims against SemGroup to a third party for approximately $10.1 million, pursuant to a purchase agreement that contains customary representations, warranties and other provisions. If a portion of the claims become impaired due to circumstances arising from a breach of such representations and warranties, then the Company may be required to repurchase such impaired portion of the claims.

See Notes I and O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's SemGroup claims and other expenses.

Income tax benefit (provision). The Company recognized an income tax benefit on continuing operations of $48.1 million during 2009 and income tax provisions on continuing operations of $201.1 million and $105.9 million during 2008 and 2007, respectively. The Company's effective tax rates for 2009, 2008 and 2007 were 25 percent, 49 percent and 32 percent, respectively, as compared to the combined United States federal and state statutory rates of approximately 37 percent. The effective tax rates differ from the combined United States federal and state statutory rates primarily due to:

- foreign tax rates;
- statutes in foreign jurisdictions that differ from those in the U.S., including a South African tax law allowing for the deduction of 150 percent of development expenditures, resulting in a $15.1 million tax benefit in 2007;
- 2009 U.S. and South African losses being consolidated with Tunisian income, which is subject to higher tax rates;
- a $54.7 million tax benefit during 2007 related to the Company's exit from West Africa;
- a $4.8 million U.S. tax benefit during 2009 and $15.8 million and $18.9 million U.S. tax provisions during 2008 and 2007, respectively, related to the Company no longer having identifiable plans to reinvest South Africa earnings in South Africa; and
- expenses for unsuccessful well costs and associated acreage costs in foreign locations where the Company does not expect to receive income tax benefits, principally attributable to unsuccessful wells in Tunisia during 2009 and 2008 and Nigeria during 2007.

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

Income (loss) from discontinued operations, net of tax. During 2009 and 2007, the Company sold its interests in the following oil and gas asset groups:

Country	Description of Asset Groups	Date Divested
Canada	Canadian assets	November 2007
United States	Mississippi assets	June 2009
United States	Gulf of Mexico shelf assets	August 2009

The results of operations of these assets and the related gains on disposition are reported as discontinued operations in the accompanying consolidated statements of operations. The Company recognized income from discontinued operations of $90.1 million during 2009 as compared to a loss from discontinued operations of $3.3 million during 2008 and income from discontinued operations of $143.2 million during 2007. The $93.4 million increase in income from discontinued operations during 2009, as compared to 2008, is attributable to (i) $119.3 million of pretax gain recognized for the recovery of excess deepwater Gulf of Mexico oil and gas royalties paid during 2003 through 2005 and (ii) a $17.5 million pretax gain from the divestiture of the Company's Mississippi assets and substantially all of the Company's Gulf of Mexico shelf properties during 2009, partially offset by (iii) a $52.6 million increase in discontinued operations tax provisions. The $146.5 million decrease in income from discontinued operations during 2008, as compared to 2007, is primarily due to the inclusion of the discontinued operations of the Company's Canadian assets that were sold for a pretax gain of $101.3 million during 2007. The aforementioned pretax gain for the recovery of excess deepwater Gulf of Mexico oil and royalties represents a receivable owed to the Company by the United States Department of Interior Minerals Management Service as of December 31, 2009 that is expected to the realized during the first half of 2009. See Note V of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's discontinued operations.

Net (income) loss attributable to noncontrolling interest. Net income attributable to noncontrolling interests was $9.8 million and $21.6 million for the years ended December 31, 2009 and 2008, respectively, as compared to net loss attributable to noncontrolling interests of $352 thousand for 2007. The Company's net income or loss attributable to noncontrolling interest is primarily associated with noncontrolling interest in the net income or loss of Pioneer Southwest allocated to limited partners. The $11.8 million decrease in net income attributable to noncontrolling interest in 2009, compared to 2008, is primarily due to an increase in Pioneer Southwest's derivative losses during 2009, subsequent to its discontinuance of hedge accounting effective February 1, 2009. The $21.9 million increase in net income attributable to noncontrolling interest in 2008, compared to 2007, is primarily due to Pioneer Southwest completing its initial public offering on May 6, 2008, resulting in income allocable to limited partners from May 6, 2008 through December 31, 2008. See Note B of Notes to Consolidated Financial Statements included in "Item 1. Financial Statements and Supplementary Data" for additional information regarding Pioneer Southwest and the Company's noncontrolling interest in consolidated subsidiaries' net income.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for capital expenditures and acquisition expenditures on oil and gas assets, payment of contractual obligations, dividends/distributions and working capital obligations. Funding for these cash needs, as well as funding for any stock or debt repurchases that the Company may undertake, may be provided by any combination of internally-generated cash flow, proceeds from the disposition of nonstrategic assets or external financing sources as discussed in "—Capital resources" below. The Company expects that it will be able to fund its needs for cash (excluding acquisitions) with internally-generated cash flows and with its liquidity under its credit facility. Although the Company expects that internal operating cash flows will be adequate to fund capital expenditures and dividend/distribution payments, and that available borrowing capacity under the Company's credit facility will provide adequate liquidity to fund other needs, no assurances can be given that such funding sources will be adequate to meet the Company's future needs.

The Company's general goal is to limit its capital budget to a level that allows the Company to deliver net cash flow from operating activities in excess of capital requirements in order to enhance and preserve financial flexibility. During the second half of 2008 and early 2009, the worldwide economic slowdown negatively impacted the demand for energy and, as a result, commodity prices declined significantly. As a result of the significant decline in commodity prices, the Company focused its efforts primarily on reducing 2009 capital spending and oil and gas production costs. These efforts resulted in the Company's 2009 capital costs (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs) decreasing to $313 million, as compared to $1.2 billion in 2008, representing a 74 percent decrease, and oil and gas production costs declining by 12 percent.

As a result of the successes realized from the Company's cost reduction initiatives and a steady increase in oil and NGL prices beginning in the second quarter of 2009, the Company has resumed oil- and liquids-rich-gas-focused drilling activities during 2010 and has preliminarily targeted its 2010 capital budget to be in a range of $800 million to $900 million (excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs). Based on current NYMEX commodity prices, the Company expects its cash flow from operating activities to be sufficient to fund its planned capital expenditures and contractual obligations.

Investing activities. Net cash used in investing activities during 2009 was $411.0 million, as compared to net cash used in investing activities of $1.2 billion and $1.8 billion during 2008 and 2007, respectively. The decrease in net cash used in investing activities during 2009, as compared to 2008, was primarily due to the cost reduction initiatives, which resulted in a $966.0 million decrease in additions to oil and gas properties and a $15.7 million decrease in additions to other assets and other property and equipment, partially offset by a $241.3 million decrease in proceeds from disposition of assets. The decrease in net cash provided by investing activities during 2008, as compared to 2007, is comprised of a $664.4 million decrease in additions to oil and gas properties and a $95.2 million decrease in additions to other assets and other property and equipment, partially offset by a $128.0 million decrease in proceeds from disposition of assets. See "—Results of Operations" above and Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

The Company has also announced plans to seek a joint venture partner for all or a portion of its Eagle Ford Shale acreage position. The Company expects to receive bids from potential joint venture partners during the second quarter of 2010 and close a transaction by mid-year. There can be no assurance that a joint venture transaction can be consummated on terms acceptable to the Company.

Dividends/distributions. During March and August 2009, the Board declared semiannual dividends of $0.04 per common share. Associated therewith, the Company paid $9.4 million of aggregate dividends during 2009. During April and October 2008, the Company paid $35.9 million ($0.30 per common share) of aggregate dividends during 2008. Future dividends are at the discretion of the Board, and, if declared, the Board may change the dividend amount based on the Company's liquidity and capital resources at the time.

During January, April, July and October 2009, the Pioneer Southwest board of directors (the "Pioneer Southwest Board") declared quarterly distributions of $0.50 per limited partner unit. Associated therewith, Pioneer Southwest paid aggregate distributions to noncontrolling unitholders of $19.0 million during 2009. During July and October 2008, the Pioneer Southwest Board declared $0.31 and $0.50 per limited partner unit distributions, respectively. Associated therewith, Pioneer Southwest paid aggregate distributions to noncontrolling unitholders of $7.7 million during 2008. Future distributions of Pioneer Southwest are at the discretion of the Board of the general partner of Pioneer Southwest, and, if declared, the Board of the general partner of Pioneer Southwest may change the distribution amount based on Pioneer Southwest's liquidity and capital resources at the time.

Off-balance sheet arrangements. From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2009, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) undrawn letters of credit, (ii) operating lease agreements, (iii) drilling commitments, (iv) VPP obligations (to physically deliver volumes and pay related lease operating expenses in the future), (v) open purchase commitments and (vi) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices and gas transportation commitments. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See "—Contractual obligations" below for more information regarding the Company's off-balance sheet arrangements.

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

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2009:

	Payments Due by Year			
	2010	**2011 and 2012**	**2013 and 2014**	**Thereafter**
		(in thousands)		
Long-term debt (a)	$ —	$ 246,110	$ 547,000	$ 2,089,985
Operating leases (b)	15,737	27,022	22,995	51,636
Drilling commitments (c)	101,543	144,889	26,762	—
Derivative obligations (d)	116,015	101,281	22,274	10,090
Open purchase commitments (e)	100,482	88,016	—	—
Other liabilities (f)	46,830	20,316	40,852	139,299
Transportation commitments (g)	27,651	53,139	37,612	39,900
VPP obligations (h)	90,215	87,021	—	—
	$ 498,473	$ 767,794	$ 697,495	$ 2,330,910

(a) See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for information regarding estimated future interest payment obligations under long-term debt obligations and Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." The amounts included in the table above represent principal maturities only.

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

(c) Drilling commitments represent future minimum expenditure commitments for drilling rig services and well commitments under contracts to which the Company was a party on December 31, 2009.

(d) Derivative obligations represent net liabilities for oil and gas commodity derivatives that were valued as of December 31, 2009. These liabilities include $17.9 million of liabilities that are fixed in amount and are not subject to continuing market risk. The ultimate settlement amounts of the remaining portions of the Company's derivative obligations are unknown because they are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Notes E and J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative obligations.

(e) Open purchase commitments primarily represent expenditure commitments for inventory ordered, but not received, as of December 31, 2009.

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

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

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

In December 2009, the Company entered into a ten-year firm transportation contract that commences upon completion of a new 675-mile pipeline spanning from Opal, Wyoming, to Malin, Oregon. Upon the pipeline's completion (currently expected during the first quarter of 2011) and in accordance with the transportation contract, the Company will transport 75,000 MMBtu per day of gas for a minimum transportation fee of $0.95 per MMBtu plus fuel, depending on the receipt point and other conditions. The Company issued a $78.0 million letter of credit during January 2010 in accordance with the terms of this agreement.

Capital resources. The Company's primary capital resources are net cash provided by operating activities, proceeds from sales of nonstrategic assets and proceeds from financing activities (principally borrowings under the Company's credit facility). If internally-generated cash flows do not meet the Company's expectations, the Company may reduce its level of capital expenditures, reduce dividend payments, and/or fund a portion of its capital expenditures using borrowings under its credit facility, issuances of debt or equity securities or from other sources, such as asset sales.

Operating activities. Net cash provided by operating activities during 2009, 2008 and 2007 was $543.1 million, $1.0 billion and $773.3 million, respectively. The decrease in net cash provided by operating activities in 2009, as compared to that of 2008, was primarily due to decreased oil, NGL and gas prices, partially offset by an increase in commodity sales volumes and decreased production costs. The increase in net cash provided by operating activities in 2008, as compared to that of 2007, was primarily due to increased sales volumes and increased oil, NGL and gas prices from continuing operations, partially offset by increased production costs.

Asset divestitures. During June and August 2009, the Company sold its Mississippi assets and its shelf properties in the Gulf of Mexico, respectively, for $23.6 million of net proceeds. Also during August 2009, Pioneer Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary of the Company, sold certain of its properties in the Spraberry Field in West Texas to Pioneer Southwest for proceeds of $168.2 million, including normal closing adjustments. The transaction value also included the assignment of 2009 through 2013 commodity price derivative positions to Pioneer Southwest. Pioneer Southwest is a partially-owned and consolidated subsidiary of the Company. Consequently, the sale of the properties from Pioneer USA to Pioneer Southwest represented a transfer among entities under common control and did not reduce the carrying values of Company's oil and gas properties. Proceeds from the sale were used to reduce Pioneer's credit facility indebtedness. Pioneer Southwest funded the acquisition with cash on hand and borrowings under its credit facility.

During 2008, the Company terminated derivative assets prior to their contractual maturity dates. The accompanying consolidated statement of cash flows for the year ended December 31, 2008 includes $155.0 million of proceeds from disposition of assets attributable to these derivative terminations.

In November 2007, the Company completed the sale of its Canadian subsidiaries for net proceeds of $525.7 million, resulting in a gain of $101.3 million. The net proceeds from the sale of the Canadian subsidiaries includes $132.8 million of proceeds that were deposited by the purchaser into the Company's Canadian escrow account pending receipt from the Canada Revenue Agency of appropriate tax certifications, which were received in January 2008. Accordingly, the accompanying consolidated statements of cash flows for the years ended December 31, 2008 and 2007, include approximately $132.0 million and $392.9 million of proceeds from disposition of assets, net of cash sold, respectively, pertaining to the sale of the Canadian subsidiaries.

Financing activities. Net cash used in financing activities for 2009 was $153.0 million, as compared to net cash provided by financing activities of $153.7 million and $1.0 billion for 2008 and 2007, respectively. During 2009, significant components of financing activities included $160 million of net principal payments on long-term debt and $61.0 million of net proceeds from an offering of common units by Pioneer Southwest, partially offset by $63.2 million of payments associated with dividends, distributions to noncontrolling interests and stock repurchases. During 2008, significant components of financing activities included $225.8 million of net borrowings under long-term debt and $166.0 million of proceeds from the initial public offering by Pioneer Southwest, partially offset by $181.5 million used to purchase 4.7 million shares of treasury stock. During 2007, significant components of financing activities included $1.3 billion of net borrowings under long-term debt and $221.4 million of net cash used to purchase 5.2 million shares of treasury stock.

The following provides a description of the Company's significant financing activities during 2009, 2008 and 2007:

- During November 2009, the Company issued 7.50% senior notes due 2020 and received proceeds, net of $11.4 million of offering discounts and costs, of $438.6 million. The Company used the net proceeds to reduce outstanding borrowings under its credit facility.
- During November 2009, Pioneer Southwest, a subsidiary of the Company, completed a public offering of 3,105,000 common units, which represents a 6.4 percent increase in limited partner interests in Pioneer Southwest, for net proceeds of $61.0 million. Pioneer Southwest used the net proceeds to repay amounts outstanding under its revolving credit facility.
- During December 2008, the Company repurchased $20.0 million principal amount of its outstanding $500.0 million of 2.875% Senior Convertible Notes, $71.5 million principal amount of its outstanding $526.9 million of 5.875% senior notes due 2016, $14.9 million principal amount of its outstanding $500.0 million of 6.65% senior notes due 2017 and $500 thousand principal amount of its outstanding $450.0 million of 6.875% senior notes due 2018. Associated therewith, the Company recognized a gain of $20.5 million, which is included in interest and other income in the accompanying consolidated statements of operations for the year ended December 31, 2008.
- On May 6, 2008, Pioneer Southwest completed its initial public offering of 9,487,500 common units, representing a 31.6 percent limited partner interest in Pioneer Southwest. Pioneer received $166.0 million of net proceeds from Pioneer Southwest in consideration for (i) an ownership interest in a subsidiary of Pioneer that owned the oil and gas properties prior to the initial public offering and (ii) an incremental ownership interest in certain of the same properties as a result of the exercise of the over-allotment option. The net proceeds from the initial public offering were used to reduce Pioneer's outstanding indebtedness. The Company consolidates Pioneer Southwest into its financial statements and reflects the public ownership as a noncontrolling interest in Pioneer Southwest's net assets.
- In conjunction with the completion of the initial public offering, Pioneer Southwest completed a $300 million unsecured revolving credit facility with a syndicate of banks, which matures in May 2013 (the "Pioneer Southwest Credit Facility"). The Pioneer Southwest Credit Facility is available for general partnership purposes, including working capital, capital expenditures and distributions.
- During January 2008, the Company issued 2.875% Senior Convertible Notes and received proceeds, net of approximately $11.3 million of underwriter discounts and offering costs, of approximately $488.7 million. The Company used the net proceeds from the offering to reduce outstanding borrowings under its credit facility.
- During April 2007, the Company amended its existing Amended and Restated $1.5 billion 5-Year Revolving Credit Agreement with an Amended and Restated 5-Year Revolving Credit Agreement to extend the maturity and improve the pricing. The credit facility provides for initial aggregate loan commitments of $1.5 billion.
- During March 2007, the Company issued $500 million of 6.65% senior notes due 2017 for net proceeds of $494.8 million. The Company used the net proceeds from the 6.65% senior notes to reduce indebtedness under its credit facility.

See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the significant financing activities.

As the Company pursues its strategy, it may utilize various financing sources, including fixed and floating rate debt, convertible securities, preferred stock or common stock. The Company cannot predict the timing or ultimate outcome of any such actions because they are subject to market conditions, among other factors. The Company may also issue securities in exchange for oil and gas properties, stock or other interests in other oil and gas companies or related assets. Additional securities may be of a class preferred to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined by the Board.

Liquidity. The Company's principal source of short-term liquidity is cash on hand and unused borrowing capacity under its credit facility. There were $240 million of outstanding borrowings under the credit facility as of December 31, 2009. Including $46.2 million of undrawn and outstanding letters of credit under the credit facility, the Company had $1.2 billion of unused borrowing capacity as of December 31, 2009. If internally-generated cash flows do not meet the Company's expectations, the Company may reduce its level of capital expenditures, reduce dividend payments, and/or fund a portion of its capital expenditures using borrowings under its credit facilities, issuances of debt or equity securities, or from other sources such as asset sales. The Company cannot provide any assurance that needed short-term or long-term liquidity will be available on acceptable terms or at all. Although the Company expects that internally-generated cash flows will be adequate to fund capital expenditures and dividend payments, and that available borrowing capacity under the Company's credit facilities will provide adequate liquidity, no assurances can be given that such funding sources will be adequate to meet the Company's future needs. For instance, the amount that the Company may borrow under the credit facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items, as described below.

The Company's credit facility is subject to certain covenants, including the maintenance of a ratio of the net present value of the Company's oil and gas properties to total debt (the "PV Ratio"). Effective April 29, 2009, the Company and its lenders amended the credit facility to provide the Company additional financial flexibility if longer-term commodity prices were to significantly deteriorate from current levels. The amendment reduced the required PV Ratio from 1.75 to 1.0 to 1.5 to 1.0 through the period ending March 31, 2011, after which time the ratio reverts to 1.75 to 1.0, and provides that the Company may include in the PV Ratio calculation 75 percent of the market value of its ownership of limited partner units of Pioneer Southwest. As of December 31, 2009, the Company was in compliance with all of its debt covenants.

The amendment also adjusted borrowing rates and commitment fees under the credit facility and changed certain provisions relating to the consequences if a lender under the credit facility defaults in its obligations under the agreement. See Note F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary data" for additional information about the Company's credit facility.

Debt ratings. The Company receives debt credit ratings from Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's rating for the Company is BB+ with a negative outlook. Moody's rating for the Company is Ba1 with a negative outlook. S&P and Moody's consider many factors in determining the Company's ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in the Company's debt ratings could negatively affect the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. The Company's net book capitalization at December 31, 2009 was $6.4 billion, consisting of $27.4 million of cash and cash equivalents, debt of $2.8 billion and stockholders' equity of $3.6 billion. The Company's debt to book capitalization decreased to 43 percent at December 31, 2009 from 44 percent at December 31, 2008, primarily due to a decrease in indebtedness. The Company's ratio of current assets to current liabilities was 1.08 to 1.00 at December 31, 2009, as compared to .70 to 1.00 at December 31, 2008.

Critical Accounting Estimates

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

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

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

Successful efforts method of accounting. The Company utilizes the successful efforts method of accounting for oil and gas producing activities as opposed to the alternate acceptable full cost method. In general, the Company believes that, during periods of active exploration, net assets and net income are more conservatively measured under the successful efforts method of accounting for oil and gas producing activities than under the full cost method. The critical difference between the successful efforts method of accounting and the full cost method is as follows: under the successful efforts method, exploratory dry holes and geological and geophysical exploration costs are charged against earnings during the periods in which they occur; whereas, under the full cost method of accounting, such costs and expenses are capitalized as assets, pooled with the costs of successful wells and charged against the earnings of future periods as a component of depletion expense. During 2009, 2008 and 2007, the Company recognized exploration, abandonment, geological and geophysical expense from continuing operations of $98.0 million, 227.5 million and $278.7 million, respectively. During 2009, 2008 and 2007, the Company recognized exploration, abandonment, geological and geophysical expense from discontinued operations of $288 thousand, $8.0 million and $15.1 million, respectively, under the successful efforts method.

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

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

The Company's proved reserve information included in this Report as of December 31, 2009, 2008 and 2007 was prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties. Estimates prepared by third parties may be higher or lower than those included herein.

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

It should not be assumed that the Standardized Measure included in this Report as of December 31, 2009 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the 2009 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See "Item 1A. Risk Factors" and "Item 2. Properties" for additional information regarding estimates of proved reserves.

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

Impairment of proved oil and gas properties. The Company reviews its proved properties to be held and used whenever management determines that events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Management assesses whether or not an impairment provision is necessary based upon estimated future recoverable proved and risk-adjusted probable and possible reserves, its outlook of future commodity prices, production and capital costs expected to be incurred to recover the reserves; discount rates commensurate with the nature of the properties and net cash flows that may be generated by the properties. Proved oil and gas properties are reviewed for impairment at the level at which depletion of proved properties is calculated. See Note S of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's impairment assessments.

Impairment of unproved oil and gas properties. At December 31, 2009, the Company carried unproved property costs of $236.7 million. Management assesses unproved oil and gas properties for impairment on a project-by-project basis. Management's impairment assessments include evaluating the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

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

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

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

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

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

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

Deferred tax asset valuation allowances. The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that its deferred tax assets will be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and reassesses the likelihood that the Company's net operating loss carryforwards and other deferred tax attributes in each jurisdiction will be utilized prior to their expiration. There can be no assurance that facts and circumstances will not materially change and require the Company to establish deferred tax asset valuation allowances in certain jurisdictions in a future period. As of December 31, 2009, the Company does not believe there is sufficient positive evidence to reverse its valuation allowances related to certain foreign tax jurisdictions.

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

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

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

Valuation of stock-based compensation. In accordance with GAAP, the Company calculates the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. The Company utilizes (a) the Black-Scholes option pricing model to measure the fair value of stock options, (b) the closing stock price on the day prior to the date of grant for the fair value of restricted stock awards and (c) the Monte Carlo simulation method for the fair value of performance unit awards.

Valuation of other assets and liabilities at fair value. In accordance with GAAP, the Company periodically measures and records certain assets and liabilities at fair value. The assets and liabilities that the Company periodically measures and records at fair value include trading securities, commodity derivative contracts and interest rate contracts. The Company also measures and reports certain financial assets and liabilities at fair value, such as notes receivable and long-term debt. The valuation methods used by the Company to measure the fair values of these assets and liabilities require considerable management judgment and estimates to derive the inputs necessary to determine fair value estimates, such as future prices, credit-adjusted risk-free rates and current volatility factors. See Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the methods used by management to estimate the fair values of these assets and liabilities.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data".

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The following quantitative and qualitative information is provided about financial instruments to which the Company was a party as of December 31, 2009, and from which the Company may incur future gains or losses from changes in commodity prices, market interest rates or foreign exchange rates.

The fair value of the Company's derivative contracts is determined based on the Company's valuation models and applications, which are validated against counterparties' estimates. The Company did not change its valuation method during 2009. During 2009, the Company was a party to commodity, interest rate and foreign exchange rate swap contracts, commodity collar contracts, commodity collar contracts with short put options and NGL percentage of West Texas Intermediate ("WTI") oil index contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2009:

	Derivative Contract Net Assets (Liabilities) (a)		
	Commodities	Interest Rate	Total
		(in thousands)	
Fair value of contracts outstanding as of December 31, 2008	$ 112,286	$ (9,903)	$ 102,383
Changes in contract fair values (b)	(170,426)	(17,212)	(187,638)
Contract maturities	(74,998)	9,274	(65,724)
Contract terminations	11,576	—	11,576
Fair value of contracts outstanding as of December 31, 2009	$ (121,562)	$ (17,841)	$ (139,403)

(a) Represents the fair values of open derivative contracts subject to market risk. The Company also had $17.9 million and $40.3 million of obligations under terminated derivatives as of December 31, 2009 and 2008, respectively, for which no market risk exists.

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

Effective February 1, 2009, the Company discontinued hedge accounting on all existing commodity derivative instruments, and since that date has accounted for derivative instruments using the MTM accounting method. Therefore, the Company recognizes changes in the fair values of its derivative contracts as gains or losses in the earnings of the period in which they occur. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's derivative contracts, including deferred gains and losses on terminated derivative contracts.

Quantitative Disclosures

Interest rate sensitivity. The following tables provide information about financial instruments to which the Company was a party as of December 31, 2009 that were sensitive to changes in interest rates. For debt obligations, the tables present maturities by expected maturity dates, the weighted average interest rates expected to be paid on the debt given current contractual terms and market conditions and the debt's estimated fair value. For fixed rate debt, the weighted average interest rate represents the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2009. For variable rate debt, the average interest rate represents the average rates being paid on the debt projected forward proportionate to the forward yield curve for LIBOR on February 23, 2010.

INTEREST RATE SENSITIVITY
DEBT OBLIGATIONS AND DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2009

	Year Ending December 31,							Liability Fair Value December 31, 2009
	2010	2011	2012	2013	2014	Thereafter	Total	
Total Debt:								
Fixed rate principal maturities (a)	$ —	$ —	$ 6,110	$ 480,000	$ —	$ 2,089,985	$ 2,576,095	$ 2,543,026
Weighted average interest rate	6.05%	6.05 %	6.04 %	6.03%	6.05%	7.07%		
Variable rate principal maturities:								
Pioneer credit facility	$ —	$ —	$240,000	$ —	$ —	$ —	$ 240,000	$ 259,461
Weighted average interest rate	2.53%	3.82 %	5.11 %					
Pioneer Southwest credit facility	$ —	$ —	$ —	$ 67,000	$ —	$ —	$ 67,000	$ 68,495
Weighted average interest rate	1.41%	2.70 %	3.99 %	4.76%				
Interest Rate Swaps:								
Notional debt amount (b)	$ 202,611	$23,625						$ 5,729
Fixed rate payable (%)	2.98%	3.00 %						
Variable rate receivable (%)	0.53%	1.82 %						
Notional debt amount (b)	$ 400,000	$400,000	$400,000	$ 400,000	$ 400,000	$ 400,000		$ 12,112
Fixed rate receivable (%)	2.87%	2.87 %	2.87 %	2.87%	2.87%	2.87%		
Variable rate payable (%)	0.53%	1.82 %	3.11 %	3.88%	3.417%	3.66%		

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

(b) Represents weighted average notional contract amounts of interest rate derivatives. Includes (i) variable-for-fixed interest rate swap contracts to offset variable interest rate risk on the Company's credit facility for notional amounts of $100 million through February 2010 and $189 million through February 2011 and (ii) fixed-for-variable interest rate swap contracts for a notional amount of $400 million through April 2016 to mitigate the current fixed rate interest charge associated with fixed rate indebtedness.

Commodity price sensitivity. The following tables provide information about the Company's oil, NGL and gas derivative financial instruments that were sensitive to changes in oil, NGL and gas prices as of December 31, 2009. Although mitigated by the Company's derivative activities, declines in commodity prices will reduce Pioneer's revenues and internally-generated cash flows. Recent uncertainties in worldwide financial markets may have the effect of reducing liquidity in the financial derivatives market, hampering the Company's ability to enter into derivative contracts under acceptable terms.

Commodity derivative instruments. The Company manages commodity price risk with derivative contracts, such as swap contracts, collar contracts, collar contracts with short put options and NGL percentage of oil index contracts. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor") and maximum ("ceiling") prices for the Company on a notional amount of sales volumes, thereby allowing some price participation if the relevant index price closes above the floor price. Collar contracts with short put options differ from other collar contracts by virtue of the short put option price, below which the Company's realized price will exceed the variable market prices by the long put-to-short put price differential. NGL percentage of WTI oil index contracts stabilize the NGL-to-NYMEX oil differential on notional NGL contract volumes.

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

OIL PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2009

	Year Ending December 31, 2010	2011	2012	2013	Asset (Liability) Fair Value at December 31, 2009 (in thousands)
Oil Derivatives:					
Average daily notional Bbl volumes (a):					
Swap contracts	2,500	750	3,000	3,000	$ (9,343)
Weighted average fixed price per Bbl	$ 93.34	$ 77.25	$ 79.32	$ 81.02	
Collar contracts	—	2,000	—	—	$ 23,107
Weighted average ceiling price per Bbl	$ —	$ 170.00	$ —	$ —	
Weighted average floor price per Bbl	$ —	$ 115.00	$ —	$ —	
Collar contracts with short puts	27,000	35,000	11,000	1,250	$ (125,727)
Weighted average ceiling price per Bbl	$ 83.84	$ 98.39	$ 115.36	$ 111.50	
Weighted average floor price per Bbl	$ 66.89	$ 73.57	$ 81.36	$ 83.00	
Weighted average short put price per Bbl	$ 53.96	$ 59.09	$ 65.00	$ 68.00	
Average forward NYMEX oil prices (b)	$ 81.51	$ 83.94	$ 85.19	$ 86.12	

(a) Subsequent to December 31, 2009, the Company entered into additional collar contracts with short puts for (i) 2,000 Bbls per day of the Company's 2011 production with a ceiling price of $113.75 per Bbl, a floor price of $80.00 per Bbl and a short put price of $65.00 per Bbl and (ii) 4,000 Bbls per day of the Company's 2012 production with a ceiling price of $127.41 per Bbl, a floor price of $80.00 per Bbl and a short put price of $65.00 per Bbl.

(b) The average forward NYMEX oil prices are based on February 19, 2010 market quotes.

NGL PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2009

	Year Ending December 31, 2010	2011	2012	2013	Liability Fair Value at December 31, 2009 (in thousands)
NGL Derivatives:					
Average daily notional Bbl volumes:					
Swap contracts	1,325	750	750	—	$ (6,276)
Weighted average fixed price per Bbl	$ 47.86	$ 34.65	$ 35.03	$ —	
Average forward Mont Belvieu NGL prices (b)	$ 45.04	$ 43.21	$ 43.00	$ —	
Collar contracts	2,000	1,000	—	—	$ (4,974)
Weighted average ceiling price per Bbl	$ 49.98	$ 50.93	$ —	$ —	
Weighted average floor price per Bbl	$ 41.58	$ 42.21	$ —	$ —	
Percent of WTI oil index contracts	1,919	—	—	—	$ (1,654)
Percentage of NYMEX WTI received	60%	—	—	—	
Average forward NYMEX oil prices (c)	$ 81.51	$ 88.94	$ —	$ —	

(a) Forward Mont Belvieu NGL prices are not available as formal market quotes. These forward prices represent estimates as of February 5, 2010 provided by third parties who actively trade in the derivatives. Accordingly, these prices are subject to estimates and assumptions.

(b) The average forward NYMEX oil prices are based on February 19, 2010 market quotes.

GAS PRICE SENSITIVITY
DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2009

	Year Ending December 31,				Asset (Liability) Fair Value at December 31, 2009
	2010	2011	2012	2013	(in thousands)
Gas Derivatives (a):					
Average daily notional MMBtu volumes:					
Swap contracts	167,500	77,500	2,500	2,500	$ 30,348
Weighted average fixed price per MMbtu	$ 6.26	$ 6.35	$ 6.77	$ 6.89	
Collar contracts	40,000	—	—	—	$ 5,313
Weighted average ceiling price per MMbtu	$ 7.19	$ —	$ —	$ —	
Weighted average floor price per MMbtu	$ 5.75	$ —	$ —	$ —	
Collar contracts with short puts	95,000	175,000	90,000	—	$ 30,250
Weighted average ceiling price per MMbtu	$ 7.94	$ 8.69	$ 8.72	$ —	
Weighted average floor price per MMbtu	$ 6.00	$ 6.36	$ 6.25	$ —	
Weighted average short put price per MMbtu	$ 5.00	$ 4.93	$ 4.61	$ —	
Average forward NYMEX gas prices (b)	$ 5.35	$ 5.90	$ 6.13	$ 6.31	
Basis swap contracts (c)	215,000	120,000	40,000	10,000	$ (62,606)
Weighted average fixed price per MMbtu	$ (0.77)	$ (0.62)	$ (0.47)	$ (0.71)	
Average forward basis differential prices (d)	$ (0.19)	$ (0.24)	$ (0.19)	$ (0.32)	

(a) Subsequent to December 31, 2009 and through February 19, 2010, the Company entered into additional collar contracts with short puts for (i) 25,000 MMBtu per day of the Company's 2011 production with a ceiling price of $7.52 per Bbl, a floor price of $6.00 per Bbl and a short put price of $4.50 per Bbl and (ii) 25,000 MMBtu per day of the Company's 2012 production with a ceiling price of $8.09 per MMBtu, a floor price of $6.00 per MMBtu and a short put price of $4.50 per MMBtu. The Company also entered into (i) additional swap contracts for 20,000 MMBtu per day and 10,000 MMBtu per day, respectively, of the Company's 2011 and 2013 production at an average price of $6.21 per MMBtu and $6.51 per MMBtu, respectively, and (ii) additional basis swap contracts for 36,849 MMBtu per day of the Company's 2010 production at an average price differential of $0.13 per MMBtu.

(b) The average forward NYMEX gas prices are based on February 19, 2010 market quotes.

(c) Represent swaps that fix the basis differentials between indices at which the Company sells its Spraberry, Mid-Continent and Gulf Coast gas and NYMEX Henry Hub index prices.

(d) The average forward basis differential prices are based on February 19, 2010 market quotes for basis differentials between the relevant index prices and NYMEX-quoted forward prices.

Qualitative Disclosures

The Company's primary market risk exposures are to changes in interest rates, foreign exchange rates and commodity prices. Such risks did not change materially from December 31, 2008 to December 31, 2009.

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

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

Foreign currency, operations and price risk. International investments represent, and are expected to continue to represent, a portion of the Company's total assets. Pioneer currently has international operations in South Africa and Tunisia, which together represented 13 percent of the Company's 2009 oil and gas revenues from continuing operations. As a result of such foreign operations, the Company's financial results and international operations could be affected by factors such as changes in foreign currency exchange rates, changes in the legal or regulatory environment, weak economic conditions or changes in political or economic climates and other factors. For example:

- local political and economic developments could restrict, or increase the cost of, the Company's foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of the Company's foreign operations;

- expropriation of the Company's property could result in loss of revenue, property and equipment;
- civil uprising, riots, terrorist attacks and wars could make it impractical to continue operations, resulting in financial losses;
- compliance with applicable U.S. law could be in conflict with the Company's contractual obligations, the laws of foreign governments or local customs;
- import and export regulations and other foreign laws or policies could result in loss of revenues;
- repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country; and
- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict the Company's ability to fund foreign operations or may make foreign operations more costly.

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

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

Item 8. Financial Statements and Supplementary Data

Index to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the "Company") as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Pioneer Natural Resources Company at December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note B to the consolidated financial statements, effective January 1, 2009, the Company retroactively changed (1) its method of calculating basic and diluted earnings per share with the adoption of the guidance originally issued in FASB Staff Position No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities" (codified in FASB ASC Topic 260, Earnings per Share), (2) its method of accounting for convertible debt instruments with the adoption of guidance originally issued in FASB Staff Position No. APB 14-1, "Accounting for Convertible Debt Instruments That May be Settled in Cash upon Conversion (Including Partial Cash Settlement)" (codified in FASB ASC Topic 740, Debt), and (3) its method for the presentation of noncontrolling interests in consolidated subsidiaries with the adoption of the guidance originally issued in FASB Statement No. 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment to ARB No. 51" (codified in FASB ASC Topic 810, Consolidation). Additionally, as discussed in Note B to the consolidated financial statements, the Company has changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements resulting from Accounting Standards Update No. 2010-03, "Oil and Gas Reserve Estimation and Disclosures," effective December 31, 2009.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Pioneer Natural Resources Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
February 26, 2010

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2009	December 31, 2008 (a)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 27,368	$ 48,337
Accounts receivable:		
Trade, net of allowance for doubtful accounts of $1,310 and $22,464 as of December 31, 2009 and 2008, respectively	330,711	206,794
Due from affiliates	1,037	759
Income taxes receivable	25,022	60,573
Inventories	139,177	76,901
Prepaid expenses	9,011	12,464
Deferred income taxes	26,857	6,510
Other current assets:		
Derivatives	48,713	59,622
Other, net of allowance for doubtful accounts of $5,689 and $5,491 as of December 31, 2009 and 2008, respectively	8,222	14,951
Total current assets	616,118	486,911
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	10,276,244	10,167,220
Unproved properties	236,660	204,183
Accumulated depletion, depreciation and amortization	(2,946,048)	(2,511,401)
Total property, plant and equipment	7,566,856	7,860,002
Deferred income taxes	387	553
Goodwill	309,259	310,563
Other property and equipment, net	154,830	161,266
Other assets:		
Derivatives	43,631	72,594
Other, net of allowance for doubtful accounts of $7,300 and $4,410 as of December 31, 2009 and 2008, respectively	176,184	269,896
	$ 8,867,265	$ 9,161,785

(a) Retrospectively adjusted as described in Note B.

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

CONSOLIDATED BALANCE SHEETS (Continued)
(in thousands, except share data)

	December 31, 2009	December 31, 2008 (a)
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 221,359	$ 322,688
Due to affiliates	32,224	34,284
Interest payable	47,009	43,247
Income taxes payable	17,411	3,618
Deferred income taxes	128	—
Other current liabilities:		
Derivatives	116,015	49,561
Deferred revenue	90,215	147,905
Other	46,830	93,694
Total current liabilities	571,191	694,997
Long-term debt	2,761,011	2,899,241
Derivatives	133,645	20,584
Deferred income taxes	1,470,899	1,502,705
Deferred revenue	87,021	177,236
Other liabilities	200,467	187,409
Stockholders' equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 125,203,502 and 124,566,963 shares issued at December 31, 2009 and 2008, respectively	1,252	1,246
Additional paid-in capital	2,981,450	2,909,735
Treasury stock, at cost: 10,828,171 and 10,020,502 shares at December 31, 2009 and 2008, respectively	(415,211)	(411,659)
Retained earnings	917,688	988,786
Accumulated other comprehensive income - deferred hedge gains, net of tax	51,009	88,788
Total stockholders' equity attributable to common stockholders	3,536,188	3,576,896
Noncontrolling interest in consolidating subsidiaries	106,843	102,717
Total stockholders' equity	3,643,031	3,679,613
Commitments and contingencies		
	$ 8,867,265	$ 9,161,785

(a) Retrospectively adjusted as described in Note B.

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

PIONEER NATURAL RESOURCES COMPANY

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

	Year Ended December 31,		
	2009	**2008 (a)**	**2007 (a)**
Revenues and other income:			
Oil and gas	$ 1,609,984	$ 2,227,581	$ 1,695,298
Interest and other	102,306	57,641	91,883
Loss on disposition of assets, net	(774)	(381)	(2,163)
	1,711,516	2,284,841	1,785,018
Costs and expenses:			
Oil and gas production	380,326	422,571	296,988
Production and ad valorem taxes	98,371	164,417	112,893
Depletion, depreciation and amortization	651,560	489,716	373,344
Impairment of oil and gas properties	21,091	89,753	26,215
Exploration and abandonments	98,046	227,500	278,657
General and administrative	140,323	141,922	129,735
Accretion of discount on asset retirement obligations	11,012	7,903	6,115
Interest	173,361	166,785	135,270
Hurricane activity, net	17,313	12,150	61,309
Derivative losses, net	195,557	10,148	2,135
Other	105,011	115,973	27,291
	1,891,971	1,848,838	1,449,952
Income (loss) from continuing operations before income taxes	(180,455)	436,003	335,066
Income tax benefit (provision)	48,108	(201,091)	(105,923)
Income (loss) from continuing operations	(132,347)	234,912	229,143
Income (loss) from discontinued operations, net of tax	90,080	(3,257)	143,233
Net income (loss)	(42,267)	231,655	372,376
Net (income) loss attributable to noncontrolling interests	(9,839)	(21,635)	352
Net income (loss) attributable to common stockholders	$ (52,106)	$ 210,020	$ 372,728
Basic earnings per share:			
Income (loss) from continuing operations attributable to common stockholders	$ (1.25)	$ 1.79	$ 1.86
Income (loss) from discontinued operations attributable to common stockholders	0.79	(0.03)	1.19
Net income (loss) attributable to common stockholders	$ (0.46)	$ 1.76	$ 3.05
Diluted earnings per share:			
Income (loss) from continuing operations attributable to common stockholders	$ (1.25)	$ 1.79	$ 1.85
Income (loss) from discontinued operations attributable to common stockholders	0.79	(0.03)	1.19
Net income (loss) attributable to common stockholders	$ (0.46)	$ 1.76	$ 3.04
Weighted average shares outstanding:			
Basic	114,176	117,462	120,158
Diluted	114,176	117,947	120,614
Amounts attributable to common stockholders:			
Income (loss) from continuing operations	$ (142,186)	$ 213,277	$ 229,495
Discontinued operations, net of tax	90,080	(3,257)	143,233
Net income (loss)	$ (52,106)	$ 210,020	$ 372,728

(a) Retrospectively adjusted as described in Note B.

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

PIONEER NATURAL RESOURCES COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands, except dividends per share)

		Stockholders' Equity Attributable to Common Stockholders							
						Accumulated Other Comprehensive Income (Loss)			
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Net Deferred Hedge Gains (Losses), Net of Tax	Cumulative Translation Adjustment	Noncontrolling Interest	Total Stockholders' Equity
Balance as of December 31, 2006 (a)	121,503	$ 1,227	$ 2,654,047	$ (53,274)	$ 497,488	$ (167,220)	$ 52,403	$ 14,376	$ 2,999,047
Dividends declared ($0.27 per share)	—	—	—	—	(32,921)	—	—	—	(32,921)
Exercise of long-term incentive plan stock options and employee stock purchases	671	—	—	29,097	(15,206)	—	—	—	13,891
Purchase of treasury stock	(5,150)	—	—	(221,424)	—	—	—	—	(221,424)
Tax benefits related to stock-based compensation	—	—	3,908	—	—	—	—	—	3,908
Compensation costs:									
Vested compensation awards, net	703	7	(7)	—	—	—	—	—	—
Compensation costs included in net income	—	—	35,309	—	—	—	—	—	35,309
Cash contributions of noncontrolling interests	—	—	—	—	—	—	—	2,932	2,932
Cash distributions to noncontrolling interests	—	—	—	—	—	—	—	(907)	(907)
Impairment of Nigerian subsidiary	—	—	—	—	—	—	—	(4,107)	(4,107)
Net income	—	—	—	—	372,728	—	—	(352)	372,376
Other comprehensive income (loss):									
Deferred hedging activity, net of tax:									
Net deferred hedge losses	—	—	—	—	—	(94,330)	—	—	(94,330)
Net hedge losses included in continuing operations	—	—	—	—	—	52,686	—	—	52,686
Net hedge gains included in discontinued operations	—	—	—	—	—	(19,393)	—	—	(19,393)
Translation adjustment:									
Deferred translation adjustment gain	—	—	—	—	—	—	77,744	—	77,744
Net gain included in discontinued operations	—	—	—	—	—	—	(130,147)	—	(130,147)
Balance as of December 31, 2007	117,727	$ 1,234	$ 2,693,257	$ (245,601)	$ 822,089	$ (228,257)	$ —	$ 11,942	$ 3,054,664
Dividends declared ($0.30 per share)	—	—	—	—	(35,952)	—	—	—	(35,952)
Exercise of long-term incentive plan stock options and employee stock purchases	355	—	—	15,439	(7,371)	—	—	—	8,068
Purchase of treasury stock	(4,714)	—	—	(181,497)	—	—	—	(240)	(181,737)
Tax benefits related to stock-based compensation	—	—	367	—	—	—	—	—	367
Compensation costs:									
Vested compensation awards, net	1,178	12	(12)	—	—	—	—	—	—
Compensation costs included in net income	—	—	33,970	—	—	—	—	107	34,077
Issuance of 2.875% senior convertible notes	—	—	49,527	—	—			—	49,527
Issuance of Pioneer Southwest common units	—	—	132,626	—	—	—	—	33,171	165,797
Cash distributions to noncontrolling interests	—	—	—	—	—	—	—	(8,635)	(8,635)
Net income	—	—	—	—	210,020	—	—	21,635	231,655
Other comprehensive income (loss):									
Deferred hedging activity, net of tax:									
Hedge fair value changes, net	—	—	—	—	—	89,152	—	49,361	138,513
Net hedge (income) loss included in continuing operations	—	—	—	—	—	227,893	—	(4,624)	223,269
Balance as of December 31, 2008	114,546	$ 1,246	$ 2,909,735	$ (411,659)	$ 988,786	$ 88,788	$ —	$ 102,717	$ 3,679,613

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

PIONEER NATURAL RESOURCES COMPANY

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

		Stockholders' Equity Attributable to Common Stockholders						
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total Stockholders' Equity
Balance as of December 31, 2008	114,546	$ 1,246	$ 2,909,735	$ (411,659)	$ 988,786	$ 88,788	$ 102,717	$ 3,679,613
Dividends declared ($0.08 per share)	—	—	—	—	(9,388)	—	—	(9,388)
Exercise of long-term incentive plan stock options and employee stock purchases	468	—	—	18,110	(9,604)	—	—	8,506
Purchase of treasury stock	(1,276)	—	—	(21,662)	—	—	(259)	(21,921)
Tax benefits related to stock-based compensation	—	—	1	—	—	—	—	1
Compensation costs:								
Vested compensation awards, net	637	6	(6)	—	—	—	—	—
Compensation costs included in net loss	—	—	38,332	—	—	—	232	38,564
Issuance of Pioneer Southwest common units	—	—	33,388			(5,844)	33,439	60,983
Cash contributions of noncontrolling interest partners	—	—	—	—	—	—	150	150
Cash distributions to noncontrolling interest partners	—	—	—	—	—	—	(20,012)	(20,012)
Net income (loss)	—	—	—	—	(52,106)	—	9,839	(42,267)
Other comprehensive income (loss):								
Deferred hedging activity, net of tax:								
Hedge fair value changes, net	—	—	—	—	—	10,477	3,692	14,169
Net hedge gains included in continuing operations	—	—	—	—	—	(42,412)	(22,955)	(65,367)
Balance as of December 31, 2009	114,375	$ 1,252	$ 2,981,450	$ (415,211)	$ 917,688	$ 51,009	$ 106,843	$ 3,643,031

(a) Retrospectively adjusted as described in Note B.

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2009	2008 (a)	2007(a)
Cash flows from operating activities:			
Net income (loss)	$ (42,267)	$ 231,655	$ 372,376
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	651,560	489,716	373,344
Impairment of oil and gas properties	21,091	89,753	26,215
Exploration expenses, including dry holes	47,241	130,140	172,028
Hurricane activity, net	19,850	9,000	66,000
Deferred income taxes	(55,712)	152,400	117,097
Loss on disposition of assets, net	774	381	2,163
Gain on extinguishment of debt	—	(20,515)	—
Accretion of discount on asset retirement obligations	11,012	7,903	6,115
Discontinued operations	(82,999)	37,454	(55,012)
Interest expense	27,996	28,492	17,049
Derivative related activity	75,633	45,166	12,084
Amortization of stock-based compensation	37,638	34,077	35,309
Amortization of deferred revenue	(147,905)	(158,139)	(181,231)
Other noncash items	35,439	60,768	3,182
Change in operating assets and liabilities			
Accounts receivable, net	16,293	45,446	(96,691)
Income taxes receivable	36,030	(20,528)	(15,378)
Inventories	(46,708)	(82,403)	(10,901)
Prepaid expenses	(3,387)	(3,405)	656
Other current assets	87,642	(11,745)	(2,946)
Accounts payable	(65,862)	65,644	30,122
Interest payable	3,762	1,227	11,012
Income taxes payable	13,793	(9,225)	(23)
Other current liabilities	(97,855)	(89,399)	(109,280)
Net cash provided by operating activities	543,059	1,033,863	773,290
Cash flows from investing activities:			
Proceeds from disposition of assets, net of cash sold	51,600	292,920	420,874
Additions to oil and gas properties	(437,240)	(1,403,272)	(2,067,648)
Additions to other assets and other property and equipment, net	(25,345)	(41,058)	(136,218)
Net cash used in investing activities	(410,985)	(1,151,410)	(1,782,992)
Cash flows from financing activities:			
Borrowings under long-term debt	1,015,842	1,032,998	2,030,000
Principal payments on long-term debt	(1,175,703)	(807,239)	(778,630)
Contributions from (distributions to) noncontrolling interest partners	(19,862)	(8,635)	2,025
Proceeds from issuance of partnership common units, net of issuance costs	60,983	165,978	—
Borrowings (payments) of other liabilities	486	(7,793)	768
Exercise of long-term incentive plan stock options	8,506	8,068	13,891
Purchase of treasury stock	(21,921)	(181,737)	(221,424)
Excess tax benefits from share-based payment arrangements	1	367	3,828
Payment of financing fees	(12,005)	(12,377)	(4,310)
Dividends paid	(9,370)	(35,917)	(32,804)
Net cash provided by (used in) financing activities	(153,043)	153,713	1,013,344
Net increase (decrease) in cash and cash equivalents	(20,969)	36,166	3,642
Effect of exchange rate changes on cash and cash equivalents	—	—	1,496
Cash and cash equivalents, beginning of period	48,337	12,171	7,033
Cash and cash equivalents, end of period	$ 27,368	$ 48,337	$ 12,171

(a) Retrospectively adjusted as described in Note B.

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(in thousands)

	Year Ended December 31,		
	2009	**2008 (a)**	**2007 (a)**
Net income (loss)	$ (42,267)	$ 231,655	$ 372,376
Other comprehensive income (loss):			
Hedge activity:			
Hedge fair value changes, net	12,974	218,202	(151,625)
Net hedge (gains) losses included in continuing operations	(114,231)	356,731	83,447
Net hedge (gains) losses included in discontinued operations	—	—	(28,125)
Income tax provision (benefit)	50,059	(213,151)	35,266
Translation adjustment:			
Deferred translation adjustment gain (loss)	—	—	77,744
Net gain included in discontinued operations	—	—	(130,147)
Other comprehensive income (loss)	(51,198)	361,782	(113,440)
Comprehensive income (loss)	(93,465)	593,437	258,936
Comprehensive (income) loss attributable to noncontrolling interest	9,424	(66,372)	352
Comprehensive income (loss) attributable to common stockholders	$ (84,041)	$ 527,065	$ 259,288

(a) Retrospectively adjusted as described in Note B.

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

NOTE A. Organization and Nature of Operations

Pioneer is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company with continuing operations in the United States, South Africa and Tunisia.

NOTE B. Summary of Significant Accounting Policies

Principles of consolidation. The consolidated financial statements include the accounts of the Company and its wholly-owned and majority-owned subsidiaries since their acquisition or formation. The Company's consolidated financial statements also include the accounts of PNR Holdings LLC as of and for the year ended December 31, 2007, which represented a variable interest entity ("VIE") in which Pioneer held a variable interest that would absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns, or both (see "Oil and gas properties" below for additional information regarding PNR Holdings LLC). In accordance with generally accepted accounting principles in the United States ("GAAP"), the Company proportionately consolidates less than 100 percent-owned affiliate partnerships that are involved in oil and gas producing activities, for which certain of its wholly-owned subsidiaries serve as general partners. The Company owns less than a 31 percent interest in the oil and gas partnerships that it proportionately consolidates. All material intercompany balances and transactions have been eliminated.

Discontinued operations. During 2009 and 2007, the Company sold its interests in the following oil and gas asset groups:

Country	Description of Asset Groups	Date Divested
Canada	Canadian assets	November 2007
United States	Mississippi assets	June 2009
United States	Gulf of Mexico shelf assets	August 2009

In accordance with GAAP, the Company has reflected the results of operations of the above divestitures as discontinued operations, rather than as a component of continuing operations. See Note V for additional information regarding discontinued operations.

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

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

Accounts and notes receivable. As of December 31, 2009 and 2008, the Company had accounts receivable – trade, net of allowances for bad debts, of $331.7 million and $207.6 million, respectively, and notes receivable, net of allowances for bad debts, of $4.7 million and $11.3 million, respectively. The Company's accounts receivable – trade are primarily comprised of oil and gas sales receivable, joint operations receivables and other receivables for which the Company does not require collateral security. The Company's notes receivable are primarily comprised of notes collateralized by drilling rigs and long-lived assets.

As of December 31, 2009, the Company's accounts receivable – trade includes a $119.3 million receivable for the recovery of excess royalties paid by the Company on qualifying deepwater leases in the Gulf of Mexico. By letter dated November 6, 2009, the United States Department of Interior Minerals Management Service notified the Company that royalty relief was available for certain payments made on qualifying deepwater leases in the Gulf of Mexico based on a

United States Supreme Court ruling during October 2009. Associated therewith, the Company applied for a refund of $119.3 million of excess royalties paid during the period from 2003 through 2005. The properties that were the source of these royalties were sold by the Company during 2006. Accordingly, the income recognized for the recovery of the excess royalties is classified as discontinued operations. See Note V for additional information regarding this matter.

As of December 31, 2009 and December 31, 2008, the Company's allowances for doubtful accounts totaled $14.3 million and $32.4 million, respectively. In accordance with Accounting Standards Codification ("ASC") Topic 450, the Company establishes allowances for bad debts equal to the estimable portions of accounts and notes receivables for which failure to collect is considered probable. The Company estimates the portions of joint interest receivables for which failure to collect is probable based on percentages of joint interest receivables that are past due. The Company estimates the portions of other receivables for which failure to collect is probable based on the relevant facts and circumstances surrounding the receivable. Allowances for doubtful accounts are recorded as reductions to the carrying values of the receivables included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations in the accounting periods during which failure to collect an estimable portion is determined to be probable.

	Year Ended December 31,	
	2009	2008
	(in thousands)	
Beginning allowance for doubtful accounts balance	$ 32,365	$ 12,230
Amount charged to costs and expenses, net	4,356	30,119
Write-offs of uncollectible accounts (a)	(22,422)	(9,984)
Ending allowance for doubtful accounts balance	$ 14,299	$ 32,365

(a) Includes $19.6 million of SemGroup bad debt allowance written off upon sale of claims receivable during 2009. See Notes I and O for additional information.

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

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

Unrealized holding gains and losses are recognized for available-for-sale securities as credits or charges to stockholders' equity and other comprehensive income (loss) during the periods in which changes in fair value occur. Realized gains and losses on the divestiture of available-for-sale securities are determined using the average cost method. The Company had no investments in available-for-sale securities as of December 31, 2009 or 2008.

Investments in unaffiliated equity securities that do not have a readily determinable fair value are measured at the lower of their original cost or the net realizable value of the investment. The Company had no significant equity security investments that did not have a readily determinable fair value as of December 31, 2009 or 2008.

Inventories. Inventories were comprised of $205.6 million and $158.7 million of materials and supplies and $3.2 million and $8.4 million of commodities as of December 31, 2009 and 2008, respectively. The Company's materials and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, chemicals, operating supplies and ordinary maintenance materials and parts. The materials and supplies inventory is primarily acquired for use in future drilling operations or repair operations and is carried at the lower of cost or market, on a first-in, first-out cost basis, by yard. "Market", in the context of inventory valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. Valuation reserve allowances for materials and supplies inventories are recorded as reductions to the carrying values of the materials and supply inventories in the Company's consolidated balance sheets and as other expense in the accompanying consolidated statements of operations. As of December 31, 2009 and 2008, the Company's materials and supplies inventory was net of $5.2 million and $4.7 million, respectively, of valuation reserve allowances. As of December 31, 2009 and 2008, the Company estimated that $69.6 million and $90.2 million, respectively, of its materials and supplies inventory would not be utilized within one year. Accordingly, those inventory values have been classified as other noncurrent assets in the accompanying consolidated balance sheets as of December 31, 2009 and 2008.

Commodities inventories are carried at the lower of average cost or market, on a first-in, first-out basis. The Company's commodities inventories consist of oil and natural gas liquids ("NGLs") held in storage. Any valuation allowances of commodities inventories are recorded as reductions to the carrying values of the commodities inventories included in the Company's consolidated balance sheets and as charges to other expense in the consolidated statements of operations. As of December 31, 2008, the Company's commodities inventories were net of $159 thousand of valuation allowances.

Oil and gas properties. The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. The Company capitalizes interest on expenditures for significant development projects, generally when the underlying project is sanctioned, until such projects are ready for their intended use. For large development projects requiring significant upfront development costs to support the drilling and production of a planned group of wells, the Company continues to capitalize interest on the portion of the development costs attributable to the planned wells yet to be drilled.

The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met:

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

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

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

The Company owns interests in four natural gas processing plants and eleven treating facilities. The Company operates two of the gas processing plants and all eleven of the treating facilities. The Company's ownership interests in the natural gas processing plants and treating facilities is primarily to accommodate handling the Company's gas production and thus are considered a component of the capital and operating costs of the respective fields that they service. To the extent that there is excess capacity at a plant or treating facility, the Company attempts to process third party gas volumes for a fee to keep the plant or treating facility at capacity. All revenues and expenses derived from third party gas volumes processed through the plants and treating facilities are reported as components of oil and gas production costs. Third party revenues generated from the plant and treating facilities for the three years ended December 31, 2009, 2008 and 2007 were $25.9 million, $39.4 million and $30.3 million, respectively. Third party expenses attributable to the plants and treating facilities for the same respective periods were $13.5 million, $14.4 million and $12.1 million. The capitalized costs of the plants and treating facilities are included in proved oil and gas properties and are depleted using the unit-of-production method along with the other capitalized costs of the field that they service.

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

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

The Company reviews its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Estimates of the sum of expected future cash flows requires management to estimate future recoverable proved and risk-adjusted probable and possible reserves, forecasts of future commodity prices, production and capital costs and discount rates. Uncertainties about these future cash flow variables cause impairment estimates to be inherently imprecise. See Note S for additional information regarding the Company's impairment assessments.

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

During December 2007, PNR Holdings LLC completed acquisitions of proved and unproved oil and gas properties located in the Raton Basin in southeastern Colorado and the Barnett Shale play in North Texas for $352.2 million. The Company caused PNR Holdings LLC to be formed pursuant to an agreement with a third party in anticipation of having the acquisitions treated as part of a tax-deferred, like-kind-exchange with the anticipated sale of oil and gas properties to Pioneer Southwest, a subsidiary of the Company. As of December 31, 2007, the Company controlled PNR Holdings LLC pursuant to a management agreement (the "Management Agreement") whereby Pioneer Natural Resources USA, Inc. ("Pioneer USA"), a wholly-owned subsidiary of the Company, provided operating and administrative management of all of PNR Holdings LLC's properties. PNR Holdings LLC financed the acquisitions with borrowings under a credit agreement ("Holdings Credit Agreement") entered into with Pioneer USA. Under the terms of the Holdings Credit Agreement and Management Agreement, PNR Holdings LLC was a VIE in which Pioneer USA received substantially all of the entity's residual returns and absorbed substantially all of the entity's losses. Pioneer USA's loans under the Holdings Credit Agreement were secured by the property interests acquired by PNR Holdings LLC. General creditors of PNR Holdings LLC may have lacked recourse as a result of Pioneer USA's secured debtor standing. During 2008, PNR Holdings LLC was acquired by the Company, became a wholly-owned subsidiary and was liquidated.

Goodwill. During 2004, the Company recorded $327.8 million of goodwill associated with a business combination. The goodwill was recorded to the Company's United States reporting unit. The Company has reduced goodwill by $18.5 million since the date of the business combination. The Company reduced the carrying value of goodwill by $1.3 million during 2009 as a charge to the gain from the sale of a portion of its United States reporting unit. The remaining $17.2 million reduction in goodwill was primarily for tax benefits associated with the exercise of fully-vested stock options assumed in conjunction with the business combination. In accordance with GAAP, goodwill is not amortized to earnings, but is assessed for impairment whenever events or circumstances indicate that impairment of the carrying value of goodwill is likely, but no less often than annually. If the carrying value of goodwill is determined to be impaired, it is reduced for the impaired value with a corresponding charge to pretax earnings in the period in which it is determined to be impaired. During the third quarter of 2009, the Company performed its annual assessment of goodwill for impairment and determined that there was no impairment. See Note S for additional information regarding the Company's impairment assessments.

Other property, plant and equipment, net. Other property, plant and equipment is recorded at cost and primarily consists of items such as heavy equipment and well servicing rigs, furniture and fixtures and leasehold improvements. Depreciation is provided over the estimated useful life of the assets using the straight-line method. At December 31, 2009 and 2008, other property, plant and equipment was net of accumulated depreciation of $219.2 million and $190.6 million, respectively.

Asset retirement obligations. The Company records a liability for the fair value of an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. Asset retirement obligations are generally capitalized as part of the carrying value of the long-lived asset. Conditional asset retirement obligations meet the definition of liabilities and are recognized when incurred if their fair values can be reasonably estimated.

Asset retirement obligation expenditures are classified as cash used in operating activities in the accompanying consolidated statements of cash flows.

Derivatives and hedging. The Company recognizes all derivative instruments as either assets or liabilities at fair value. Derivative instruments that are not hedges must be adjusted to fair value through earnings. Under the provisions of GAAP, the Company may designate a derivative instrument as hedging the exposure to changes in the fair value of an asset or a liability or an identified portion thereof that is attributable to a particular risk (a "fair value hedge") or as hedging the exposure to variability in expected future cash flows that are attributable to a particular risk (a "cash flow hedge"). Both at the inception of a hedge and on an ongoing basis, a fair value hedge must be expected to be highly effective in achieving offsetting changes in fair value attributable to the hedged risk during the periods that a hedge is designated. Similarly, a cash flow hedge must be expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. The expectation of hedge effectiveness must be supported by matching the essential terms of the hedged asset, liability or forecasted transaction to the derivative hedge contract or by effectiveness assessments using statistical measurements. The Company's policy is to assess hedge effectiveness at the end of each calendar quarter.

Changes in the fair value of derivative instruments that are fair value hedges are offset against changes in the fair value of the hedged assets, liabilities, or firm commitments through earnings. Effective changes in the fair value of derivative instruments that are cash flow hedges are recognized in accumulated other comprehensive income – net deferred hedge gains, net of tax ("AOCI – Hedging") in the stockholders' equity section of the Company's consolidated balance sheets until such time as the hedged items are recognized in earnings. Ineffective portions of a derivative instrument's change in fair value are immediately recognized in earnings.

Prior to December 2008, the Company had elected to designate the majority of its commodity derivative instruments as cash flow hedges. During December 2008, the Company began entering into commodity derivative contracts that were not designated as hedges. Changes in the fair values of non-hedge derivative instruments are recognized as gains or losses in the earnings of the period in which they occur. Effective February 1, 2009, the Company discontinued hedge accounting on all existing hedge contracts. The effective portions of the discontinued deferred hedges as of February 1, 2009 are included in AOCI – Hedging and are being transferred to earnings during the same periods in which the hedged transactions are recognized in the Company's earnings. Since February 1, 2009, the Company has recognized, and in the future will recognize, changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which they occur.

The Company classifies the fair value amounts of derivative assets and liabilities executed under master netting arrangements as net derivative assets or net derivative liabilities, whichever the case may be, by commodity and master netting counterparty. Net derivative asset values are determined, in part, by utilization of the derivative counterparties' credit-adjusted risk-free rate curves and net derivative liabilities are determined, in part, by utilization of the Company's credit-adjusted risk-free rate curve. The credit-adjusted risk-free rates are based on an independent market-quoted credit default swap rate curve for the Company's or the counterparties' debt plus the United States Treasury Bill yield curve as of December 31, 2009.

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

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

Noncontrolling interest in consolidated subsidiaries. On May 6, 2008, Pioneer Southwest completed its initial public offering, at a per-unit offering price of $19.00, of 9,487,500 common units, representing a 31.6 percent limited partner interest in Pioneer Southwest. Associated therewith, the Company recognized $166.0 million of net proceeds from the issuance of Pioneer Southwest common units in net cash provided by financing activities in the accompanying consolidated statement of cash flows for the year ended December 31, 2008 and recognized a $132.6 million noncash gain on the sale of Pioneer Southwest common units in the accompanying consolidated statement of stockholders' equity for the year ended December 31, 2008. Pioneer Southwest owns interests in certain oil and gas properties previously owned by the Company in the Spraberry field in the Permian Basin of West Texas. Upon completion of the initial offering, the Company owned a 0.1 percent general partner interest and a 68.3 percent limited partner interest in Pioneer Southwest. The financial position, results of operations, and cash flows of Pioneer Southwest are consolidated with those of the Company. The Company elected to account for gains on Pioneer Southwest's issuance of common units as equity transactions. The financial position, results of operations, and cash flows of Pioneer Southwest are consolidated with those of the Company.

On November 16, 2009, Pioneer Southwest completed a public offering (the "Secondary Offering") of 3,105,000 common units, at a per unit offering price of $19.82, representing limited partner interests, which resulted in the increase of noncontrolling interest ownership of Pioneer Southwest from 31.6 percent to 38 percent and decreased the Company's limited ownership interest from 68.3 percent to 61.9 percent. Associated therewith, the Company recognized $61.0 million of net proceeds from the Secondary Offering in net cash used in financing activities in the accompanying statement of cash flows for the year ended December 31, 2009 and recognized a $33.4 million noncash gain on the sale of Pioneer Southwest common units in the accompanying statement of stockholders' equity for the year ended December 31, 2009.

In addition to Pioneer Southwest, the Company owns the majority interests in certain other subsidiaries with operations in the United States. Noncontrolling interest in the net assets of consolidated subsidiaries totaled $106.8 million and $102.7 million as of December 31, 2009 and 2008, respectively. The Company recorded net income (loss) attributable to the noncontrolling interests of $9.8 million, $21.6 million and $(352) thousand for the years ended December 31, 2009, 2008 and 2007 (principally related to Pioneer Southwest in 2009 and 2008), respectively. See "New accounting pronouncements" and "Reclassifications and retrospective adjustments" for information regarding the Company's accounting for noncontrolling interests.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

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

The Company uses the entitlements method of accounting for oil, NGL and gas revenues. Sales proceeds in excess of the Company's entitlement are included in other liabilities and the Company's share of sales taken by others is included in other assets in the accompanying consolidated balance sheets.

The Company had no material oil entitlement assets or NGL entitlement assets or liabilities as of December 31, 2009 or 2008. The following table presents the Company's oil entitlement liabilities and gas entitlement assets and liabilities with their associated volumes as of December 31, 2009 and 2008:

	December 31,			
	2009		2008	
	Amount	Volume	Amount	Volume
	(dollars in millions)			
Oil entitlement liabilities (volumes in MBbls)	$ 1.6	22	$ 0.5	13
Gas entitlement assets (volumes in MMcf)	$ 7.6	2,967	$ 8.9	3,227
Gas entitlement liabilities (volumes in MMcf)	$ 3.3	781	$ 6.1	1,288

Stock-based compensation. For stock-based compensation awards granted or modified, compensation expense is being recognized in the Company's financial statements on a straight line basis over their vesting periods based on their fair values on the dates of grant. The Company utilizes (i) the Black-Scholes option pricing model to measure the fair value of stock options, (ii) the prior day's closing stock price on the date of grant for the fair value of restricted stock awards and (iii) the Monte Carlo simulation method for the fair value of performance unit awards.

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

Prior to their sale in November 2007, the functional currency of the Company's Canadian operations was the Canadian dollar. The financial statements of the Company's Canadian subsidiaries were translated to U.S. dollars as follows: all assets and liabilities were translated using the exchange rate in effect at the end of each reporting period; revenues and costs and expenses were translated using the average of the exchange rates that were in effect during the period in which the revenues and costs and expenses were recognized. The resulting gains or losses from translating Canadian dollar denominated balances were recorded in the accompanying consolidated statements of stockholders' equity for the period through accumulated other comprehensive income (loss)—cumulative translation adjustment ("AOCI-CTA").

During November 2007, the Company completed the divestiture of its Canadian subsidiaries. As such, the net cumulative translation adjustment previously deferred in AOCI-CTA was recognized as part of the gain on sale of the Canadian subsidiaries. The Company's Canadian subsidiary's statement of operations for the year ended December 31, 2007 was translated from Canadian dollars to U.S. dollars using a .9365 average annual exchange rate. See Note V for a discussion of the Company's discontinued operations, which include the historical operating results of its Canadian subsidiaries.

New accounting pronouncements. The following discussions provide information about new accounting pronouncements that were issued by the Financial Accounting Standards Board ("FASB") during 2009, 2008 and 2007:

SFAS 157. In September 2006, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measures," which was primarily codified into ASC Topic 820. This guidance defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measures required under other accounting pronouncements, but does not change existing guidance as to whether or not an instrument is carried at fair value. During February 2008, the FASB issued FASB Staff Position No. 157-2, "FSP FAS 157-2," which was also primarily codified into ASC Topic 820. This guidance delayed the effective date of the previous guidance for nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis at least annually. On January 1, 2009, the Company adopted the remaining provisions of ASC Topic 820, for which delayed adoption was allowed.

SFAS 141(R). In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations," which was primarily codified into ASC Topic 805. This guidance replaced SFAS 141 and provides greater consistency in the accounting and financial reporting of business combinations. It requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction and any noncontrolling interest in the acquired entity at the acquisition date, measured at their fair values as of the date that the acquirer achieves control over the business acquired. This includes the measurement of the acquirer's shares issued in consideration for a business combination, the recognition of contingent consideration, the recognition of pre-acquisition contractual and certain non-contractual gain and loss contingencies, the recognition of capitalized research and development costs and the recognition of changes in the acquirer's income tax valuation allowance and deferred taxes. These provisions also require that restructuring costs resulting from the business combination that the acquirer expects but is not required to incur and costs incurred to effect the acquisition be recognized separate from the business combination. The Company became subject to these provisions of ASC Topic 805 on January 1, 2009.

SFAS 160. In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB Statement No. 51," which was primarily codified into ASC Topic 810. This guidance amended Accounting Research Bulletin ("ARB") No. 51, "Consolidated Financial Statements," which is also primarily codified into ASC Topic 810, to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This guidance clarifies that a noncontrolling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, it requires consolidated earnings to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. The Company retrospectively adopted these provisions of ASC Topic 810 on January 1, 2009.

SFAS 161. In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133," which was primarily codified into ASC Topic 815. This guidance changed the disclosure requirements for derivative instruments and hedging activities by requiring entities to provide enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which was primarily codified into ASC Topic 815 and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. These provisions of ASC Topic 815 were adopted by the Company on January 1, 2009. See Notes E and J for disclosures about the Company's derivative instruments and hedging activities.

FSP APB 14-1. In May 2008, the FASB issued FASB Staff Position No. APB 14-1, "Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)," which was primarily codified into ASC Topic 470. This guidance specifies that issuers of such instruments should separately account for the liability and equity components of convertible debt instruments that may be settled in cash upon conversion in a manner that will reflect the entity's nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The Company retrospectively adopted the provisions of ASC Topic 470 on January 1, 2009. The adoption increased the annual interest expense that the Company recognizes on its $480 million of 2.875% convertible senior notes due 2038 ("2.875% Convertible Senior Notes") from an annual yield of 2.875 percent to 6.75 percent, the annual yield equivalent to a nonconvertible debt borrowing at the time of issuance. The adoption also resulted in the reclassification of the estimated issuance date fair value of the 2.875% Convertible Senior Notes conversion privilege from long-term debt to shareholders' equity in the accompanying consolidated balance sheets. See "Reclassifications and retrospective adjustments" below and Note F for additional information regarding the Company's adoption of the provisions of ASC Topic 470.

FSP EITF 03-6-1. In June 2008, the FASB issued FASB Staff Position No. EITF 03-6-1, "Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities," which was primarily codified into ASC Topic 260, which addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the net income (loss) allocation in computing basic and diluted earnings per share under the two class method prescribed under SFAS 128, "Earnings per Share," which was primarily codified into ASC Topic 260. The Company retrospectively adopted these new provisions of ASC Topic 260 on January 1, 2009 and applied its provisions retrospectively to prior-period earnings per share computations. See Note Q for additional information regarding the Company's basic and diluted earnings per share computations.

SEC reserve ruling. In December 2008, the SEC released the final rule on, "Modernization of Oil and Gas Reporting" (the "Reserve Ruling"). The Reserve Ruling revises oil and gas reporting disclosures. The Reserve Ruling also permits the use of new technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. The Reserve Ruling will also allow companies to disclose their probable and possible reserves to investors. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor, (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit and (iii) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Reserve Ruling became effective for annual reports on Forms 10-K for fiscal years ending on or after December 31, 2009. During December 2009, the FASB issued Accounting Standards Update No. 2010-03, "Extractive Activities – Oil and Gas (Topic 932)," ("ASU 2010-03") to conform to GAAP to the Reserve Ruling. The Company adopted the provisions of the Reserve Ruling and the provisions of ASU 2010-03 on December 31, 2009. See Unaudited Supplementary Information for information regarding the adoption of the Reserve Ruling.

SFAS 165. In May 2009, the FASB issued SFAS No. 165, "Subsequent Events," which was primarily codified into ASC Topic 855. This guidance establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. The provisions of ASC Topic 855 were adopted by the Company on June 30, 2009. See Note W for the Company's subsequent events disclosures.

SFAS 168. In June 2009, the FASB issued SFAS No. 168, "The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles – a replacement of FASB Statement No. 162," which was primarily codified into ASC Topic 105. This guidance creates a new source of authoritative U.S. accounting and reporting standards for nongovernmental entities, known as the FASB "Accounting Standards Codification." The provisions of ASC Topic 105 were adopted by the Company on September 30, 2009.

Reclassifications and retrospective adjustments. Certain reclassifications have been made to the 2008 and 2007 amounts in order to conform to the 2009 presentation and for the retrospective application of the adoption of ASC Topic 810. The retrospective application of ASC Topic 810 resulted in the reclassification of $59.2 million and $11.9 million, respectively, from minority interest in consolidated subsidiaries at December 31, 2008 and 2007 and $44.8 million from AOCI – Hedging to Noncontrolling interest in consolidated subsidiaries at December 31, 2008. In addition, the adoption of ASC Topic 470 and ASC Topic 260 required retrospective adjustments to the Company's financial statements as of December 31, 2008 and the years ended December 31, 2008 and 2007. The retrospective adjustments related to the adoption of ASC Topic 470 (i) decreased interest and other income – gain on early extinguishment of the debt by $2.7 million, (ii) increased the Company's interest expense by $13.2 million and (iii) decreased the Company's income from continuing operations and net income attributable to common stockholders by $10.0 million (approximately $.08 per diluted share) for the year ended December 31, 2008. The retrospective application of ASC Topic 470 also increased additional paid-in capital by $49.5 million and decreased retained earnings by $10.0 million as of December 31, 2008. The retrospective application of the provisions of ASC Topic 260 reduced the Company's diluted earnings of the years ended December 31, 2008 and 2007 by approximately $.01 per share and $.02 per share, respectively, exclusive of the effects from the adoption of ASC Topic 470.

NOTE C. Proved Property Acquisitions

During the years ended December 31, 2009, 2008 and 2007, the Company expended $8.8 million, $87.5 million and $331.6 million, respectively, to acquire working interests in proved oil and gas properties. During 2009, 2008 and 2007, the Company's proved oil and gas property acquisitions were principally in the United States. During 2009, the Company's proved acquisitions were in the West Texas Permian Basin area. During 2008, the Company's proved acquisitions primarily comprised property interests in the South Texas Edwards Trend, the West Texas Permian Basin and the Barnett Shale play in North Texas. During 2007, the Company's proved acquisitions primarily comprised property interests in the West Texas Permian Basin, the Colorado Raton Basin, the Barnett Shale play in North Texas and onshore Gulf Coast.

NOTE D. Exploratory Well Costs

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in proved properties in the consolidated balance sheets. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense.

The following table reflects the Company's capitalized exploratory well activity during each of the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Beginning capitalized exploratory well costs	$ 124,014	$ 130,630	$ 265,053
Additions to exploratory well costs pending the determination of proved reserves	80,222	403,692	434,321
Reclassification due to determination of proved reserves	(58,792)	(321,436)	(388,630)
Disposition of wells sold	—	—	(20,369)
Exploratory well costs charged to exploration expense (a)	(17,870)	(88,872)	(159,745)
Ending capitalized exploratory well costs	$ 127,574	$ 124,014	$ 130,630

(a) Includes exploratory well costs of discontinued operations of $4.4 million in 2007.

The following table provides an aging, as of December 31, 2009, 2008 and 2007 of capitalized exploratory well costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year, based on the date drilling was completed:

	Year Ended December 31,		
	2009	2008	2007
	(in thousands, except well counts)		
Capitalized exploratory well costs that have been suspended:			
One year or less	$ 21,634	$ 54,423	$ 76,237
More than one year	105,940	69,591	54,393
	$ 127,574	$ 124,014	$ 130,630
Number of projects with exploratory well costs that have been suspended for a period greater than one year	8	4	8

The following table provides an aging of capitalized costs of exploration projects that have been suspended for more than one year as of December 31, 2009:

	Total	2009	2008	2007	2006
United States:					
Cosmopolitan Unit	$ 66,914	$ 8,253	$ 6,344	$ 51,488	$ 829
Other	5,624	797	4,827	—	—
Tunisia	33,402	466	29,006	(15)	3,945
Total	$ 105,940	$ 9,516	$ 40,177	$ 51,473	$ 4,774

Cosmopolitan Unit. The Company owns a 100 percent working interest in, and is the operator of, the Cosmopolitan Unit in the Cook Inlet of Alaska. During 2007, the Company drilled the Hansen #1A L1 well, a lateral sidetrack from an existing wellbore, to appraise the resource potential of the unit. The initial unstimulated production test results were encouraging. As a result, the Company began permitting and facilities planning during 2008 to further evaluate the unit's resource potential. During 2009, the Company progressed engineering studies and commenced a workover of the Hansen #1A-L1 well. During 2010, the Company plans to complete the Hansen #1A-L1 workover, fracture stimulate the well, flow test the well, evaluate the production flow rate information from the fractured well test, progress project permitting and develop plans for a second well to further delineate the extent of the unit's resource potential.

Tunisia – Cherouq. The Company has $17.6 million of suspended well costs recorded for the Hayatt #1 well in the Company's Cherouq production concession area, which is operated by the Company. The Hayatt #1 well began drilling in April 2008 to test several targeted formations. Mechanical failures were encountered during the testing of the well that did not allow completion of the formation assessments. The Company is analyzing seismic and other data to determine the optimal plan forward for completing the well, which may utilize the existing wellbore or a new wellbore adjacent to the existing well. The Company expects to finalize its Hayatt #1 plans and complete its assessment activities during 2010 or early 2011.

Tunisia – Borj El Khadra prospects. The Company has $7.8 million of suspended well costs attributable to the Nahkil #1 and Abir #1 wells in the Borj El Khadra exploration permit area, which is operated by a third-party. The Nahkil #1 well encountered oil-bearing sands and the Abir #1 well encountered gas-bearing sands. The Company does not record proved reserves associated with discoveries in exploration permit areas until a production concession is granted. Infrastructure planning is underway. The Company intends to acquire an additional 850 square kilometers of 3-D seismic data on the permit area and drill an additional exploratory well during 2010.

Tunisia – Anaguid exploration permit. The Company has $8.1 million of suspended well costs attributable to the Durra #1 well on the Anaguid exploration permit. During 2009, the Company submitted a plan of development to request government approval to convert a portion of the existing exploration permit surrounding the Durra #1 well into a production concession. The Company also plans to drill up to two additional Anaguid exploration wells during 2010.

NOTE E. Disclosures About Fair Value Measurements

In accordance with GAAP, fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

- Level 1 – quoted prices for identical assets or liabilities in active markets.
- Level 2 – quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; inputs other than quoted prices that are observable for the asset or liability (e.g. interest rates); and inputs derived principally from or corroborated by observable market data by correlation or other means.
- Level 3 – unobservable inputs for the asset or liability.

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement in its entirety.

The following tables present the Company's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2009 and 2008 for each of the fair value hierarchy levels:

	Fair Value Measurements at Reporting Date Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at December 31, 2009
	(in thousands)			
Assets:				
Trading securities	$ 251	$ 84	$ —	$ 335
Commodity derivatives	—	82,678	1,402	84,080
Interest rate derivatives	—	8,264	—	8,264
Deferred compensation plan assets	27,890	—	—	27,890
Notes receivable	—	—	4,727	4,727
Total assets	$ 28,141	$ 91,026	$ 6,129	$ 125,296
Liabilities:				
Commodity derivatives	$ —	$ 209,249	$ 14,306	$ 223,555
Interest rate derivatives	—	26,105	—	26,105
Pioneer credit facility	—	259,461	—	259,461
Pioneer Southwest credit facility	—	68,495	—	68,495
5.875% senior notes due 2012	6,154	—	—	6,154
5.875% senior notes due 2016	437,170	—	—	437,170
6.65% senior notes due 2017	472,546	—	—	472,546
6.875% senior notes due 2018	438,402	—	—	438,402
7.50% senior notes due 2020	449,566	—	—	449,566
7.20% senior notes due 2028	230,868	—	—	230,868
2.875% senior convertible notes due 2038 (a)	508,320	—	—	508,320
Total liabilities	$ 2,543,026	$ 563,310	$ 14,306	$ 3,120,642

(a) The fair value of the 2.875% senior convertible notes includes the fair value of the conversion privilege.

	Fair Value Measurements at Reporting Date Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at December 31, 2008
	(in thousands)			
Assets:				
Trading securities	$ 301	$ 55	$ —	$ 356
Commodity derivatives	—	112,608	18,560	131,168
Deferred compensation plan assets	18,276	—	—	18,276
Notes receivable	—	—	11,258	11,258
Total assets	$ 18,577	$ 112,663	$ 29,818	$ 161,058
Liabilities:				
Commodity derivatives	$ —	$ 18,882	$ —	$ 18,882
Interest rate derivatives	—	9,903	—	9,903
Credit facility	—	868,597	—	868,597
5.875% senior notes due 2012	5,233	—	—	5,233
5.875% senior notes due 2016	301,583	—	—	301,583
6.65% senior notes due 2017	339,570	—	—	339,570
6.875% senior notes due 2018	292,175	—	—	292,175
7.20% senior notes due 2028	145,000	—	—	145,000
2.875% senior convertible notes due 2038 (a)	345,600	—	—	345,600
Total liabilities	$ 1,429,161	$ 897,382	$ —	$ 2,326,543

(a) The fair value of the 2.875% senior convertible notes includes the fair value of the conversion privilege.

The following tables present the changes in the fair values of the Company's net commodity derivative assets (liabilities) and notes receivable classified as Level 3 in the fair value hierarchy for the year ended December 31, 2009:

Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	Year Ended December 31, 2009				
	NGL Contracts	Gas Three-Way Collars	Oil Three-Way Collars	Notes Receivable	Total
	(in thousands)				
Beginning balance	$ 18,560	$ —	$ —	$ 11,258	$ 29,818
Total gains (losses):					
Net unrealized gains (losses) included in earnings (a)	(20,206)	(1,697)	3,364	1,072	(17,467)
Net derivative losses included in other comprehensive loss	(1,855)	—	—	—	(1,855)
Net realized losses transferred to earnings (a)	(8,340)	—	—	—	(8,340)
Notes receivable valuation allowance included in earnings (b)	—	—	—	(6,163)	(6,163)
Settlements	(1,063)	—	—	(1,452)	(2,515)
Transfers into/out of Level 3	—	1,697	(3,364)	12	(1,655)
Ending balance	$ (12,904)	$ —	$ —	$ 4,727	$ (8,177)

(a) The hedge-effective portions of realized gains and losses on commodity derivatives in AOCI— Hedging are included in oil and gas revenues, while non-hedge derivatives or ineffective portions of realized and unrealized hedge derivatives gains and losses are included in net derivative losses in the accompanying consolidated statements of operations.

(b) The valuation allowance associated with the Company's notes receivable is included in other expense in the accompanying consolidated statements of operations.

The following table presents the carrying amounts and fair values of the Company's financial instruments as of December 31, 2009 and 2008:

	December 31, 2009		December 31, 2008	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Assets:				
Commodity price derivatives	$ 84,080	$ 84,080	$ 132,216	$ 132,216
Interest rate derivatives	$ 8,264	$ 8,264	$ —	$ —
Trading securities	$ 335	$ 335	$ 356	$ 356
Deferred compensation plan assets	$ 27,890	$ 27,890	$ 18,276	$ 18,276
Notes receivable due 2008 to 2011	$ 4,727	$ 4,727	$ 11,258	$ 11,258
Liabilities:				
Commodity price derivatives	$ 223,555	$ 223,555	$ 60,242	$ 60,242
Interest rate derivatives	$ 26,105	$ 26,105	$ 9,903	$ 9,903
Pioneer credit facility	$ 240,000	$ 259,461	$ 913,000	$ 868,597
Pioneer Southwest credit facility	$ 67,000	$ 68,495	$ —	$ —
5.875 % senior notes due 2012	$ 6,168	$ 6,154	$ 6,191	$ 5,233
5.875 % senior notes due 2016	$ 389,109	$ 437,170	$ 382,010	$ 301,583
6.65 % senior notes due 2017	$ 483,914	$ 472,546	$ 483,792	$ 339,570
6.875 % senior notes due 2018	$ 449,161	$ 438,402	$ 449,132	$ 292,175
7.50 % senior notes due 2020	$ 446,172	$ 449,566	$ —	$ —
7.20 % senior notes due 2028	$ 249,924	$ 230,868	$ 249,922	$ 145,000
2.875% senior convertible notes due 2038 (a)	$ 429,563	$ 508,320	$ 415,194	$ 345,600

(a) The fair value of the 2.875% senior convertible notes includes the fair value of the conversion privilege.

Trading securities and deferred compensation plan assets. The Company's trading securities represent equity securities that are not actively traded on major exchanges and trading securities that are actively traded on major exchanges. The Company's deferred compensation plan assets represent investments in equity and mutual fund securities that are actively traded on major exchanges plus unallocated contributions as of the measurement date. As of December 31, 2009, all significant inputs to these asset exchange values represented Level 1 independent active exchange market price inputs except inputs for trading securities that are not actively traded on major exchanges, which were provided by broker quotes representing Level 2 inputs.

Notes receivable. The fair value of the Company's notes receivable approximates the carrying values based on the adequacy of the collateral security and interest yields. The balance of the Company's notes receivable is included in other current assets, net in the accompanying consolidated balance sheets.

Interest rate derivatives. The Company's interest rate derivative assets and liabilities as of December 31, 2009 represent (i) swap contracts for $289 million notional amount of debt, whereby the Company pays a fixed rate of interest and the counterparty pays a variable LIBOR-based rate and (ii) swap contracts for $400 million notional amount of debt, whereby the Company pays a variable LIBOR-based rate and the counterparty pays a fixed rate of interest. The net derivative liability values attributable to the Company's interest rate derivative contracts as of December 31, 2009 are based on (i) the contracted notional amounts, (ii) LIBOR rate yield curves provided by counterparties and corroborated with forward active market-quoted LIBOR rate yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative liabilities as of December 31, 2008 represent swap contracts for $400 million notional amount of debt, whereby the Company paid a fixed rate of interest and the counterparty paid a variable LIBOR-based rate. The Company's interest rate derivative asset and liability measurements represent Level 2 inputs in the hierarchy priority.

Commodity derivatives. The Company's commodity derivatives represent oil, NGL and gas swap contracts, collar contracts and collar contracts with short puts (which are also known as three-way collar contracts). The Company's oil and gas swap, collar and three-way collar derivative contract asset and liability measurements represent Level 2 inputs in the hierarchy priority while NGL derivative contract asset and liability measurements represent Level 3 inputs in the hierarchy priority.

Oil derivatives. The Company's oil derivatives are swap, collar and three-way collar contracts for notional Bbls of oil at fixed (in the case of swap contracts) or interval (in the case of collar and three-way collar contracts) NYMEX West Texas Intermediate ("WTI") oil prices. The asset and liability values attributable to the Company's oil derivatives as of December 31, 2009 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for WTI oil, (iii) the applicable estimated credit-adjusted risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar and three-way collar contracts. The implied rates of volatility inherent in the Company's collar contracts were determined based on average volatility factors provided by certain independent brokers who are active in buying and selling oil options and were corroborated by market-quoted volatility factors.

NGL derivatives. The Company's NGL derivatives are swap and collar contracts for notional blended Bbls of Mont Belvieu-posted-price NGLs or NGL component prices per Bbl. The asset and liability values attributable to the Company's NGL derivatives as of December 31, 2009 are based on (i) the contracted notional volumes, (ii) average forward Mont Belvieu-posted-price quotes and NGL component price quotes supplied by independent brokers who are active in buying and selling NGL derivative contracts and (iii) the applicable credit-adjusted risk-free rate yield curve. The implied rates of volatility inherent in the Company's collar contracts were determined based on average volatility factors provided by certain independent brokers who are active in buying and selling NGL options.

Gas derivatives. The Company's gas derivatives are swap, collar and three-way collar contracts for notional MMBtus of gas contracted at various posted price indexes, including NYMEX Henry Hub ("HH") swap contracts coupled with basis swap contracts that convert the HH price index point to other price indexes. The asset and liability values attributable to the Company's gas derivative contracts as of December 31, 2009 are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH gas, (iii) averages of forward posted price quotes supplied by independent brokers who are active in buying and selling gas derivatives at the indexes other than HH, which were corroborated by market-quoted forward index prices, (iv) the applicable credit-adjusted risk-free rate yield curve and (v) the implied rate of volatility inherent in the collar and three-way collar contracts. The implied rates of volatility inherent in the Company's collar contracts and three-way collar contracts were determined based average volatility factor quotes provided by independent brokers who are active buying and selling gas options and corroborated by market-quoted volatility quotes.

Credit facility. The fair value of the Company's credit facility is based on (i) contractual interest and fees, (ii) forward active market-quoted LIBOR rate yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve.

Senior notes. The Company's senior notes represent debt securities that are actively traded on major exchanges.

Concentrations of credit risk. As of December 31, 2009, the Company's primary concentration of credit risks are the risks of collecting accounts receivable – trade and notes receivable and the risk of counterparties' failure to perform under derivative obligations. See Note B for information regarding the Company's accounts receivable – trade and notes receivable, including collateralization of notes receivable, and Note K for information regarding the Company's major customers.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative assets receivable from the defaulting party. See Note J for additional information regarding the Company's derivative activities and Note K for information regarding derivative assets and liabilities by counterparty.

NOTE F. Long-term Debt

Long-term debt, including the effects of net deferred fair value hedge losses and issuance discounts and premiums, consisted of the following components at December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(in thousands)	
Outstanding debt principal balances:		
Pioneer credit facility	$ 240,000	$ 913,000
Pioneer Southwest credit facility	67,000	—
5.875% senior notes due 2012	6,110	6,110
5.875% senior notes due 2016	455,385	455,385
6.65% senior notes due 2017	485,100	485,100
6.875 % senior notes due 2018	449,500	449,500
7.500 % senior notes due 2020	450,000	—
7.20% senior notes due 2028	250,000	250,000
2.875% senior notes due 2038	480,000	480,000
	2,883,095	3,039,095
Issuance discounts and premiums, net	(119,819)	(137,346)
Net deferred fair value hedge losses	(2,265)	(2,508)
Total long-term debt	$ 2,761,011	$ 2,899,241

Credit Facility. During April 2007, the Company entered into an Amended and Restated 5-Year Revolving Credit Agreement (the "Credit Facility") with a syndicate of financial institutions that matures in April 2012, unless extended in accordance with the terms of the Credit Facility. The Credit Facility provides for aggregate loan commitments of $1.5 billion. As of December 31, 2009, the Company had $240 million of outstanding borrowings under the Credit Facility and $46.2 million of undrawn letters of credit, all of which were commitments under the Credit Facility, leaving the Company with $1.2 billion of unused borrowing capacity under the Credit Facility.

Effective April 29, 2009, the Company and the lenders amended the Credit Facility to provide the Company additional financial flexibility. The Credit Facility contains certain financial covenants, one of which required the Company to maintain a ratio of the net present value of the Company's oil and gas properties to total debt of at least 1.75 to 1.0 until the Company achieves an investment grade rating by Moody's Investors Service, Inc. or Standard & Poors Ratings Group, Inc. The amendment changed the ratio maintenance requirement to 1.5 to 1.0 through the period ending March 31, 2011, after which time the ratio reverts to 1.75 to 1.0, and further provides that the Company may include in the calculation of the present value of its oil and gas properties 75 percent of the market value of its ownership of limited partner units of Pioneer Southwest. The covenant requiring the Company to maintain a ratio of total debt to total capitalization of no more than 0.60 to 1.0 was not changed. The variables on which the calculation of net present value is based (including assumed commodity prices and discount rates) are subject to adjustment by the lenders and, therefore, the amount that the Company may borrow under the Credit Facility in the future could be reduced as a result of lower oil, NGL or gas prices, among other items. The lenders may declare any outstanding obligations under the Credit Facility immediately due and payable upon the occurrence, and during the continuance of, an event of default. As of December 31, 2009, the Company was in compliance with all of its debt covenants.

The amendment also adjusted certain borrowing rates and commitment fees, and changed certain provisions relating to the consequences if a lender under the Credit Facility defaults in its obligations under the agreement. After taking into account the amendment, revolving loans under the Credit Facility bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by JPMorgan Chase Bank or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 0.5 percent plus a defined alternate base rate spread margin ("ABR Margin"), which is currently one percent based on the Company's debt rating or (b) a base Eurodollar rate, substantially equal to LIBOR, plus a margin (the "Applicable Margin"), which is currently two percent and is also determined by the Company's debt rating. Swing line loans under the Credit Facility bear interest at a rate per annum equal to the "ASK" rate for Federal funds periodically published by the Dow Jones Market Service plus the Applicable Margin. Letters of credit outstanding under the Credit Facility are subject to a per annum fee, representing the Applicable Margin plus 0.125 percent. The Company also pays commitment fees on undrawn amounts under the Credit Facility that are determined by the Company's debt rating (currently 0.375 percent).

In May 2008, Pioneer Southwest entered into a $300 million unsecured revolving credit facility with a syndicate of financial institutions, which matures in May 2013 (the "Pioneer Southwest Credit Facility"). As of December 31, 2009, there were $67.0 million of outstanding borrowings under the Pioneer Southwest Credit Facility. The Pioneer Southwest Credit Facility is available for general partnership purposes, including working capital, capital expenditures and distributions. Borrowings under the Pioneer Southwest Credit Facility may be in the form of Eurodollar rate loans, base rate committed loans or swing line loans. Eurodollar rate loans bear interest annually at LIBOR, plus a margin (the "Applicable Rate") (currently 0.875 percent) that is determined by a reference grid based on Pioneer Southwest's consolidated leverage ratio. Base rate committed loans bear interest annually at a base rate equal to the higher of (i) the Federal Funds Rate plus 0.5 percent or (ii) the Bank of America prime rate (the "Base Rate") plus a margin (currently zero percent). Swing line loans bear interest annually at the Base Rate plus the Applicable Rate.

The Pioneer Southwest Credit Facility contains certain financial covenants, including (i) the maintenance of a quarter end maximum leverage ratio of not more than 3.5 to 1.00, (ii) an interest coverage ratio (representing a ratio of earnings before depreciation, depletion and amortization; impairment of long-lived assets; exploration expense; accretion of discount on asset retirement obligations; interest expense; income taxes; gain or loss on the disposition of assets; noncash commodity hedge and derivative related activity; and noncash equity-based compensation to interest expense) of not less than 2.5 to 1.0 and (iii) the maintenance of a ratio of the net present value of Pioneer Southwest's projected future cash flows from its oil and gas assets to total debt of at least 1.75 to 1.0. As of December 31, 2009, Pioneer Southwest was in compliance with all of its debt covenants.

Because of the net present value covenant contained in the Pioneer Southwest Credit Facility, unused borrowing capacity is currently limited to approximately $225 million. The variables on which the calculation of net present value is based (including assumed commodity prices and discount rates) are subject to adjustment by the lenders. As a result, further declines in commodity prices could reduce Pioneer Southwest's borrowing capacity under the Pioneer Southwest Credit Facility. In addition, the Pioneer Southwest Credit Facility contains various covenants that limit, among other things, Pioneer Southwest's ability to grant liens, incur additional indebtedness, engage in a merger, enter into transactions with affiliates, pay distributions or repurchase equity and sell its assets. If any default or event of default (as defined in the Pioneer Southwest Credit Facility) were to occur, the Pioneer Southwest Credit Facility would prohibit Pioneer Southwest from making distributions to unitholders. Such events of default include, among other things, nonpayment of principal or interest, violations of covenants, bankruptcy and material judgments and liabilities.

Senior notes. During November 2009, the Company issued $450 million of 7.50% Senior Notes due 2020 and received proceeds, net of approximately $11.4 million of offering discounts and costs, of approximately $438.6 million. The Company used the net proceeds to reduce outstanding borrowings under its credit facility.

Senior convertible notes. During January 2008, the Company issued $500 million of 2.875% Convertible Senior Notes, of which $480 million remains outstanding at December 31, 2009. Effective January 1, 2009, the Company adopted the new provisions of ASC Topic 470, the provisions of which were applied on a retrospective basis. The adoption of the new provisions of ASC Topic 470 effective January 1, 2009 decreased the carrying value of the 2.875% Convertible Senior Notes by $63.5 million, increased stockholders' equity by $39.5 million and increased deferred tax liabilities by $24.0 million. For the year ended December 31, 2009, the adoption increased interest expense by $14.4 million and increased the Company's net loss by approximately $9.1 million ($.08 per diluted share).

The 2.875% Senior Convertible Notes will be convertible under certain circumstances, using a net share settlement process, into a combination of cash and the Company's common stock pursuant to a formula. The initial base conversion price is approximately $72.60 per share (subject to adjustment in certain circumstances), which is equivalent to an initial base conversion rate of 13.7741 common shares per $1,000 principal amount of convertible notes. In general, upon conversion of a note, the holder of such note will receive cash equal to the principal amount of the note and the Company's common stock for the note's conversion value in excess of such principal amount. If at the time of conversion the applicable price of the Company's common stock exceeds the base conversion price, holders will receive up to an additional 8.9532 shares of the Company's common stock per $1,000 principal amount of notes, as determined pursuant to a specified formula.

The 2.875% Senior Convertible Notes mature on January 15, 2038 (the "Maturity Date"). The Company may redeem the 2.875% Senior Convertible Notes for cash at any time on or after January 15, 2013 at a price equal to 100 percent of the principal amount plus accrued and unpaid interest. Holders of the 2.875% Senior Convertible Notes may require the Company to purchase their 2.875% Senior Convertible Notes for cash at a price equal to 100 percent of the principal amount plus accrued and unpaid interest if certain defined fundamental changes occur, as defined in the agreement, or on January 15, 2013, 2018, 2023, 2028 or 2033. Additionally, holders may convert their notes at their option in the following circumstances:

- Following defined periods during which the reported sales prices of the Company's common stock exceeds 130 percent of the base conversion price (initially $72.60 per share);
- During five-day periods following defined circumstances when the trading price of the 2.875% Senior Convertible Notes is less than 97 percent of the price of the Company's common stock times a defined conversion rate;
- Upon notice of redemption by the Company; and
- During the period beginning October 15, 2037, and ending at the close of business on the business day immediately preceding the Maturity Date.

Interest on the principal amount of the 2.875% Senior Convertible Notes is payable semiannually in arrears on January 15 and July 15 of each year, beginning July 15, 2008. Beginning on January 15, 2013, during any six-month period thereafter from January 15 to July 14 and from July 15 to January 14, if the average trading day price of a 2.875% Senior Convertible Note for the five consecutive trading days immediately preceding the first day of the applicable six-month interest period equals or exceeds $1,200, interest on the principal amount of the 2.875% Senior Convertible Notes will be 2.375% solely for the relevant interest period.

As of December 31, 2009 and 2008, the 2.875% Senior Convertible Notes had an unamortized discount of $50.4 million and $64.8 million, respectively, and a net carrying value of $429.6 million and $415.2 million, respectively. The unamortized discount is being amortized ratably through January 2013. For the years ended December 31, 2009 and 2008, the Company recorded $29.9 million and $28.8 million, respectively, of interest expense relating to the 2.875% Senior Convertible Notes, which had an effective interest rate of 6.75 percent.

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

Early extinguishment of debt. During December 2008, the Company repurchased $20.0 million principal amount of its outstanding $500 million of 2.875% Senior Convertible Notes, $71.5 million principal amount of its outstanding $526.9 million of 5.875% senior notes due July 15, 2016, $14.9 million principal amount of its outstanding $500.0 million of 6.65% senior notes due March 15, 2017 and $500 thousand principal amount of its outstanding $450.0 million of 6.875% senior notes due April 30, 2018. Associated therewith, the Company recognized a gain of $20.5 million, which is included in interest and other income in the accompanying consolidated statement of operations for the year ended December 31, 2008.

Principal maturities. Principal maturities of long-term debt at December 31, 2009, are as follows (in thousands):

2010	$	—
2011	$	—
2012	$	246,110
2013	$	547,000
2014	$	—
Thereafter	$	2,089,985

The principal maturities during 2013 in the preceding table represent the Company's 2.875% Senior Convertible Notes, which mature in 2038, but are subject to repurchase by the Company at the option of the holders in 2013.

Interest expenses. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Cash payments for interest	$ 151,254	$ 156,002	$ 139,624
Accretion/amortization of discounts or premiums on loans	21,388	20,523	6,707
Accretion of discount on derivative obligations	874	3,151	7,306
Accretion of discount on postretirement benefit obligations	657	631	1,150
Amortization of net deferred hedge losses (see Note J)	465	483	434
Amortization of capitalized loan fees	4,612	3,703	1,452
Net changes in accruals	3,762	1,227	11,149
Interest incurred	183,012	185,720	167,822
Less capitalized interest	(9,651)	(18,935)	(32,552)
Total interest expense	$ 173,361	$ 166,785	$ 135,270

NOTE G. Related Party Transactions

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

The activities with affiliated partnerships are summarized for the following related party transactions for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Receipt of lease operating and supervision charges in accordance with standard industry operating agreements	$ 2,224	$ 2,064	$ 1,835
Reimbursement of general and administrative expenses	$ 265	$ 415	$ 364

NOTE H. Incentive Plans

Retirement Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Board of Directors (the "Board") approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary and 100 percent of their annual bonus. The Company will provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first ten percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan. The Company's matching contributions were \$1.7 million, \$1.6 million and \$1.4 million for the years ended December 31, 2009, 2008 and 2007, respectively.

401(k) plan. The Pioneer USA 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount up to 80 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's base compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four-year period that begins with the participant's date of hire. During the years ended December 31, 2009, 2008 and 2007, the Company recognized compensation expense of $11.8 million, $11.4 million and $10.9 million, respectively, as a result of Matching Contributions.

Pioneer Long-Term Incentive Plan

In May 2006, the Company's stockholders approved a new Long-Term Incentive Plan, which provides for the granting of incentive awards in the form of stock options, stock appreciation rights, performance units, restricted stock and restricted stock units to directors, officers and employees of the Company. The Long-Term Incentive Plan initially provided for the issuance of 4.6 million shares pursuant to awards under the plan. In May 2009, the shareholders of the Company approved an amendment to the plan authorizing the issuance of an additional 4.5 million shares pursuant to awards under the plan.

The following table shows the number of shares available for issuance pursuant to awards under the Company's Long-Term Incentive Plan at December 31, 2009:

Approved and authorized awards	9,100,000
Awards issued after May 3, 2006	(4,886,567)
Awards available for future grant	4,213,433

Compensation costs. In accordance with GAAP, the Company records compensation expense, equal to the award-date fair value of share-based payments, ratably over the vesting periods of the Long-Term Incentive Plan awards and to record compensation expense associated with the Company's Employee Stock Purchase Plan ("ESPP").

For the years ended December 31, 2009, 2008 and 2007, the Company recorded $38.6 million, $34.1 million and $35.3 million, respectively of stock-based compensation costs for all plans, including compensation costs of $907 thousand, $422 thousand and $606 thousand, respectively, associated with the Company's ESPP.

As of December 31, 2009, there was $44.8 million of unrecognized share-based compensation expense related to awards of unvested restricted stock, restricted stock units, performance units and stock options. As of December 31, 2009, unrecognized compensation expense related to unvested share-based compensation plan awards is being recognized on a straight-line basis over the remaining vesting periods of the awards, which is a remaining weighted average period of less than three years.

Restricted stock awards. During 2009, 2008 and 2007, the Company issued 2,206,455, 1,170,026 and 831,799, respectively, of restricted shares of the Company's common stock or restricted stock units as compensation to directors, officers and employees of the Company. The Company's issued shares, as reflected in the consolidated balance sheets as of December 31, 2009 and 2008, do not include 979,493 and 1,078,267, respectively, of issued but unvested shares awarded under stock-based compensation plans that have voting rights.

The following table reflects the outstanding restricted stock shares or unit awards as of December 31, 2009, 2008 and 2007 and activity related thereto for the years then ended:

	Year Ended December 31,					
	2009		2008		2007	
	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price
Restricted stock awards:						
Outstanding at beginning of year	2,002,267	$ 43.87	2,158,594	$ 40.90	2,126,547	$ 39.32
Shares granted (a)	2,206,455	$ 15.45	1,170,026	$ 45.59	831,799	$ 40.61
Shares forfeited	(88,123)	$ 27.89	(148,404)	$ 43.21	(96,811)	$ 41.12
Lapse of restrictions (b)	(636,539)	$ 43.46	(1,177,949)	$ 40.23	(702,941)	$ 35.74
Outstanding at end of year	3,484,060	$ 26.35	2,002,267	$ 43.87	2,158,594	$ 40.90

(a) The grant-date fair value of restricted stock shares and units awarded during 2009, 2008 and 2007 was $34.1 million, $53.3 million and $33.8 million, respectively.

(b) The fair value of shares for which restrictions lapsed during 2009, 2008 and 2007 was $11.7 million, $54.5 million and $29.1 million, respectively.

For the 2009-2010 director year, the Company's non-employee directors were offered a choice to receive their annual fee retainers as (i) 100 percent in restricted stock units, (ii) 100 percent in cash or (iii) a combination of 50 percent cash and 50 percent restricted stock units. All non-employee directors also received an annual equity grant of restricted stock units.

Stock option awards. During 2009, the Company granted 361,021 stock option awards to certain of the Company's officers. The Company did not grant any stock options during 2008 or 2007.

A summary of the Company's stock option awards as of December 31, 2009, 2008 and 2007, and changes during the years then ended, are presented below:

	Year Ended December 31,					
	2009		2008		2007	
	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price	Number Of Shares	Weighted Average Price
Nonstatutory stock options:						
Outstanding at beginning of year	660,519	$ 21.36	974,745	$ 20.99	1,601,495	$ 20.50
Options awarded (a)	361,021	$ 15.62	—	$ —	—	$ —
Options expired	(99,250)	$ 21.13	(1,825)	$ 20.83	(5,790)	$ 33.54
Options exercised (b)	(326,257)	$ 20.08	(312,401)	$ 20.19	(620,960)	$ 19.62
Outstanding at end of year	596,033	$ 18.62	660,519	$ 21.36	974,745	$ 20.99
Exercisable at end of year (c)	235,012	$ 23.24	660,519	$ 21.36	974,745	$ 20.99

(a) The grant-date fair value of options awarded during 2009 was $2.3 million. The Company estimated the fair value of the options awarded during 2009 using the Black-Scholes method and assuming (i) an annual risk-free interest rate of 3.33 percent, (ii) an expected life of seven years, (iii) an expected volatility factor of 43 percent (representing a seven year historic volatility factor) and (iv) an annual expected dividend yield of 1.85 percent. Option awards have a 10 year contractual life.

(b) The intrinsic value of options exercised during 2009, 2008 and 2007 was $3.1 million, $12.9 million and $17.7 million, respectively.

(c) The intrinsic value of exercisable options as of December 31, 2009 is $5.9 million.

The following table summarizes information about the Company's stock options outstanding and exercisable at December 31, 2009:

	Options Outstanding and Exercisable			
Range of Exercise Price	Number Outstanding at December 31, 2009	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value at December 31, 2009
				(in thousands)
$5-$11	3,727	0.9 years	$ 11.78	$ 136
$12-$18	396,060	3.2 years	$ 15.60	12,900
$19-$26	196,246	0.9 years	$ 24.86	4,575
	596,033			$ 17,611

Performance unit awards. During 2009, 2008 and 2007, the Company awarded performance units to certain of the Company's officers under the Long-Term Incentive Plan. The following table summarizes the changes in performance unit awards during the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
Beginning performance unit awards	295,443	142,326	—
Awards	189,247	162,951	145,820
Lapsed restrictions (a)	(137,659)	—	(817)
Forfeitures	—	(9,834)	(2,677)
Ending performance unit awards	347,031	295,443	142,326

(a) On the dates of lapse, the fair values of performance units for which restrictions lapsed during 2009 and 2007 was $4.8 million and $37 thousand, respectively.

A maximum of 473,118 shares of the Company's common stock may be issued under the 2009 performance unit awards after a 34-month service period ending on December 31, 2011 and a maximum of 394,460 shares of the Company's common stock may be issued under the 2008 performance unit awards after a 34-month service period ending on December 31, 2010. On December 31, 2009, the service period lapsed on the 2007 performance unit awards. The 2007 performance unit awards earned 0.75 shares for each vested award, representing 101,084 aggregate shares of common stock. The actual shares, if any, to be issued at the end of the performance unit service periods is based on the Company's total share return ("TSR") ranking against a defined peer group's individual TSRs. The aggregate grant date fair values of the outstanding 2009 and 2008 performance unit awards is $8.7 million, based on a per-unit fair value of $15.29 and $37.01 for the 2009 and 2008 awards, respectively, as of their grant dates, which amounts were determined using the Monte Carlo simulation method and is being recognized as compensation expense ratably over the service period. The Company recognized $4.9 million, $3.7 million and $1.8 million, respectively, of compensation expense attributable to the performance unit awards during 2009, 2008 and 2007.

Pioneer Southwest Long-Term Incentive Plan

In May 2008, the board of directors of the general partner (the "General Partner") of Pioneer Southwest adopted a new Long-Term Incentive Plan (the "Pioneer Southwest LTIP"), which provides for the granting of incentive awards in the form of options, unit appreciation rights, phantom units, restricted units, unit awards and other unit-based awards to directors, employees and consultants of the General Partner and its affiliates who perform services for Pioneer Southwest. The Pioneer Southwest LTIP limits the number of units that may be delivered pursuant to awards granted under the plan to 3,000,000 common units.

The following table shows the number of awards available under the Partnership's LTIP at December 31, 2009:

Approved and authorized awards	3,000,000
Awards issued after May 6, 2008	(25,539)
Awards available for future grant	2,974,461

During 2009, the General Partner awarded 12,909 restricted common units to directors of the General Partner under the Pioneer Southwest LTIP, of which 2,038 units vest ratably over three years and 10,871 units vest in May 2010. During May 2008, the General Partner awarded 12,630 restricted units to directors of the General Partner under the Pioneer Southwest LTIP. The Company recognized $232 thousand and $107 thousand of general and administrative expense during 2009 and 2008, respectively, associated with the Pioneer Southwest LTIP awards.

As of December 31, 2009, there was $152 thousand of unrecognized compensation expense related to unvested restricted unit awards under the Pioneer Southwest LTIP. Unrecognized compensation expense related to unvested restricted units awards is being amortized on a straight-line basis over the remaining vesting periods of the awards, which is a remaining period of less than three years.

The following table reflects the outstanding restricted unit awards as of December 31, 2009 and December 31 2008, and the activity related thereto for the year then ended:

	Year Ended December 31, 2009		Year Ended December 31, 2008	
	Number Of Units	Weighted Average Price	Number Of Units	Weighted Average Price
Restricted unit awards:				
Outstanding at beginning of year	12,630	$ 19.00	—	$ —
Units granted	12,909	$ 18.26	12,630	$ 19.00
Lapse of restrictions	(8,418)	$ 19.00	—	$ —
Outstanding at end of year	17,121	$ 18.45	12,630	$ 19.00

Employee Stock Purchase Plan

The Company has an ESPP that allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the eight-month offering period (January 1 to August 31). Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each offering period, whichever closing sales price is lower. During the years ended December 31, 2009, 2008 and 2007, the Company recognized compensation expense of $907 thousand, $422 thousand and $606 thousand, respectively, associated with the ESPP.

Postretirement Benefit Obligations

At December 31, 2009 and 2008, the Company had $9.1 million and $9.6 million, respectively, of unfunded accumulated postretirement benefit obligations, the current and noncurrent portions of which are included in other current liabilities and other liabilities, respectively, in the accompanying consolidated balance sheets. These obligations are comprised of five plans of which four relate to predecessor entities that the Company acquired in prior years. These plans had no assets as of December 31, 2009 or 2008. Other than the Company's retirement plan, the participants of these plans are not current employees of the Company.

At December 31, 2009, the accumulated postretirement benefit obligations related to these plans were determined by independent actuaries for four plans representing $6.0 million of unfunded accumulated postretirement benefit obligations and by the Company for one plan representing $3.1 million of unfunded accumulated postretirement benefit obligations. The undiscounted accumulated post retirement benefit obligations were discounted at five percent to value the benefit obligations. Certain of the aforementioned plans provide for medical cost subsidies for plan participants. Annual medical cost escalation trends of nine percent were forecasted for 2010, declining annually to five percent in 2014 and thereafter, were employed to estimate the accumulated postretirement benefit obligations associated with the medical cost subsidies.

The following table reconciles changes in the Company's unfunded accumulated postretirement benefit obligations during the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Beginning accumulated postretirement benefit obligations	$ 9,612	$ 10,494	$ 19,837
Net benefit payments	(1,430)	(1,526)	(968)
Service costs	228	190	1,036
Net actuarial losses (gains)	8	(177)	(10,561)
Accretion of interest	657	631	1,150
Ending accumulated postretirement benefit obligations	$ 9,075	$ 9,612	$ 10,494

Estimated benefit payments and service/interest costs associated with the plans for the year ending December 31, 2010 are $1.0 million and $754 thousand, respectively.

NOTE I. Commitments and Contingencies

Severance agreements. The Company has entered into severance and change in control agreements with its officers, subsidiary company officers and certain key employees. The current annual salaries for the parent company officers, the subsidiary company officers and key employees covered under such agreements total $43.8 million.

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

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

MOSH Holding. On April 11, 2005, the Company and its principal United States subsidiary, Pioneer Natural Resources USA, Inc., were named as defendants in *MOSH Holding, L.P. v Pioneer Natural Resources Company; Pioneer Natural Resources USA, Inc.; Woodside Energy (USA) Inc.; and JPMorgan Chase Bank, N.A.,* as Trustee of the Mesa Offshore Trust (the "Trust"), which was formerly pending before the Judicial District Court of Harris County, Texas (334th Judicial District) (the "Court"). In April, 2009, the Company and all parties in the lawsuit reached an agreement to settle the lawsuit. Under the terms of the settlement agreement, the Company paid to the Trust the sum of $13.0 million in exchange for a full and final release of all claims made or that could have been made in the lawsuit (the "Claims"). In September, 2009, the Court entered a final judgment approving the settlement and dismissing all Claims. Certain unit holders in the Trust filed an appeal in Texas state court seeking to reverse the Court's final judgment, but subsequently withdrew the appeal. The settlement became final and non-appealable on February 1, 2010.

Colorado Notice of Violation. On May 13, 2008, the Company was served with a Notice of Violation/Cease and Desist Order by the State of Colorado Department of Public Health and Environmental Water Quality Control Division. The Notice alleges violations of stormwater discharge permits in the Company's Raton Basin and Lay Creek operations, specifically deficiencies in the Company's stormwater management plans, failure to implement and maintain best management practices to protect stormwater runoff and failure to conduct inspections of the stormwater management system. The Company has filed an answer to the Notice asserting defenses to the allegations. The Company does not believe that the outcome of this proceeding will materially impact the Company's liquidity, financial position or future results of operations.

SemGroup accounts receivable. The Company was a creditor in the bankruptcy of SemGroup, L.P. and certain of its subsidiaries (collectively, "SemGroup"), which filed petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code on July 22, 2008 in the U.S. Bankruptcy Court for the District of Delaware. In total, the Company had delinquent receivables from SemGroup of $29.6 million, representing claims for condensate sold pre-petition to SemGroup.

The Company determined that it was probable that the collection of the pre-petition claims would not occur for a protracted period of time and that some of its claims may have been uncollectible. Consequently, the Company recorded a bad debt expense of $19.6 million during the third quarter 2008, which reduced the carrying value of the claims to $10.0 million.

In April 2009, the Company sold all of its pre-petition claims against SemGroup to a third party for $10.1 million, pursuant to a purchase agreement that contains customary representations, warranties and other provisions. If a portion of the claims become impaired due to circumstances arising from a breach of such representations and warranties, then the Company may be required to repurchase such impaired portion of the claims.

Obligations following divestitures. In April 2006, the Company provided the purchaser of its Argentine assets certain indemnifications. The Company remains responsible for certain contingent liabilities related to such indemnifications, subject to defined limitations. The Company does not believe that these obligations, which primarily pertain to matters of litigation, environmental contingencies, royalty obligations and income taxes, are probable of having a material adverse effect on its liquidity, financial position or future results of operations.

The Company has also retained certain liabilities and indemnified buyers for certain matters in connection with other divestitures, including the sale in 2007 of its Canadian assets.

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

Lease agreements. The Company leases drilling rigs, offshore production facilities, equipment and office facilities under noncancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2009, 2008 and 2007 were $30.5 million, $49.6 million and $47.0 million, respectively, which includes $1.7 million associated with discontinued operations in 2007. Future minimum lease commitments under noncancellable operating leases at December 31, 2009 are as follows (in thousands):

2010	$	15,737
2011	$	13,884
2012	$	13,138
2013	$	12,079
2014	$	10,916
Thereafter	$	51,636

Transportation agreements. The Company is party to contractual commitments with pipeline carriers for the future transportation of gas production from certain of the Company's properties located in the Raton and Uinta Basins. The Raton Basin transportation commitments averaged approximately 218 million cubic feet ("MMcf") of gross gas volumes per day during 2009, including fuel commitments, and will average approximately 230 MMcf per day of gross gas volume during 2010, decreasing to approximately 221 MMcf per day per day during each of 2011 and 2012 and 200 MMcf per day during 2013, and will decline thereafter to approximately 15 MMcf per day during 2022.

The Uinta Basin transportation commitments commenced during June 2007 and averaged approximately 13 MMcf of gross gas volumes per day during 2009, including fuel commitments, and will average approximately 15 MMcf per day during 2010, and 15 MMcf per day thereafter. The Uinta Basin transportation commitments terminate during 2012, but may be extended for a period of up to three years at the option of the Company.

Future minimum transportation fees under the Company's gas transportation commitments at December 31, 2009 are as follows (in thousands):

2010	$	27,651
2011	$	26,926
2012	$	26,213
2013	$	22,796
2014	$	14,816
Thereafter	$	39,900

In December 2009, the Company entered into a ten-year firm transportation contract that commences upon completion of a new 675-mile pipeline spanning from Opal, Wyoming to Malin, Oregon. Upon the pipeline's completion (currently expected during the first quarter of 2011) and in accordance with the transportation contract, the Company is committed to transport 75,000 MMBtu per day of gas for a minimum transportation fee of $0.95 per MMBtu plus fuel, depending on the receipt point and other conditions. The Company issued a $78.0 million letter of credit during January 2010 in accordance with the terms of this agreement.

NOTE J. Derivative Financial Instruments

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

All derivative contracts are recorded on the balance sheet at estimated fair value. Fair value is generally determined based on the credit-adjusted present value difference between the fixed contract price and the underlying market price at the determination date. Effective February 1, 2009, the Company discontinued hedge accounting on all existing derivative instruments and since that date has accounted for derivative instruments using the mark-to-market ("MTM") accounting method. Therefore, the Company recognizes all changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which they occur.

Changes in the fair value of effective cash flow hedges prior to the Company's discontinuance of hedge accounting on February 1, 2009 were recorded as a component of AOCI – Hedging, which is transferred to earnings when the hedged transaction is recognized in earnings. Any ineffective portions of changes in the fair value of hedge derivatives prior to February 1, 2009 were recorded in the earnings of the periods of change. The ineffective portions were calculated as the difference between the change in fair value of the hedge derivative and the estimated change in cash flows from the item hedged.

Fair value derivatives. The Company monitors the debt capital markets and interest rate trends to identify opportunities to enter into and terminate interest rate derivative contracts, with the objective of reducing the Company's costs of capital. As of December 31, 2009 and December 31, 2008, the Company was not a party to any fair value hedges.

Cash flow derivatives. The Company utilizes commodity swap contracts, collar contracts and collar contracts with short puts 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. The Company also, from time to time, utilizes interest rate contracts to reduce the effect of interest rate volatility on the Company's indebtedness and forward currency exchange rate agreements to reduce the effect of exchange rate volatility.

Oil prices. All material physical sales contracts governing the Company's oil production have been tied directly or indirectly to NYMEX oil prices.

The following table sets forth the volumes in Bbls underlying the Company's outstanding oil derivative contracts and the weighted average NYMEX prices per Bbl for those contracts as of December 31, 2009:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily oil production derivatives (a):					
2010 – Swap contracts					
Volume (Bbl)	2,500	2,500	2,500	2,500	2,500
Price per Bbl	$ 93.34	$ 93.34	$ 93.34	$ 93.34	$ 93.34
2010 – Collar Contracts with short puts					
Volume (Bbl)	26,750	27,000	27,000	27,250	27,000
Price per Bbl:					
Ceiling	$ 83.79	$ 83.82	$ 83.82	$ 83.94	$ 83.84
Floor	$ 66.86	$ 66.89	$ 66.89	$ 66.92	$ 66.89
Short put	$ 53.95	$ 53.96	$ 53.96	$ 53.97	$ 53.96
2011 – Swap contracts					
Volume (Bbl)	750	750	750	750	750
Price per Bbl	$ 77.25	$ 77.25	$ 77.25	$ 77.25	$ 77.25
2011 – Collar contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl:					
Ceiling	$ 170.00	$ 170.00	$ 170.00	$ 170.00	$ 170.00
Floor	$ 115.00	$ 115.00	$ 115.00	$ 115.00	$ 115.00
2011 – Collar contracts with short puts					
Volume (Bbl)	35,000	35,000	35,000	35,000	35,000
Price per Bbl:					
Ceiling	$ 98.39	$ 98.39	$ 98.39	$ 98.39	$ 98.39
Floor	$ 73.57	$ 73.57	$ 73.57	$ 73.57	$ 73.57
Short put	$ 59.09	$ 59.09	$ 59.09	$ 59.09	$ 59.09
2012 – Swap contracts					
Volume (Bbl)	3,000	3,000	3,000	3,000	3,000
Price per Bbl	$ 79.32	$ 79.32	$ 79.32	$ 79.32	$ 79.32
2012 – Collar contracts with short put					
Volume (Bbl)	11,000	11,000	11,000	11,000	11,000
Price per Bbl:					
Ceiling	$ 115.36	$ 115.36	$ 115.36	$ 115.36	$ 115.36
Floor	$ 81.36	$ 81.36	$ 81.36	$ 81.36	$ 81.36
Short put	$ 65.00	$ 65.00	$ 65.00	$ 65.00	$ 65.00
2013 – Swap contracts					
Volume (Bbl)	3,000	3,000	3,000	3,000	3,000
Price per Bbl	$ 81.02	$ 81.02	$ 81.02	$ 81.02	$ 81.02
2013 – Collar contracts with short puts					
Volume (Bbl)	1,250	1,250	1,250	1,250	1,250
Price per Bbl:					
Ceiling	$ 111.50	$ 111.50	$ 111.50	$ 111.50	$ 111.50
Floor	$ 83.00	$ 83.00	$ 83.00	$ 83.00	$ 83.00
Short put	$ 68.00	$ 68.00	$ 68.00	$ 68.00	$ 68.00

(a) Subsequent to December 31, 2009, the Company entered into collar contracts with short puts for (i) 2,000 Bbls per day of the Company's 2011 production with a ceiling price of $113.75 per Bbl, a floor price of $80.00 per Bbl and a short put price of $65.00 per Bbl and (ii) 4,000 Bbls per day of the Company's 2012 production with a ceiling price of $127.41 per Bbl, a floor price of $80.00 per Bbl and a short put price of $65.00 per Bbl.

Natural gas liquids prices. All material physical sales contracts governing the Company's NGL production have been tied directly or indirectly to Mont Belvieu prices. Historically, NGL market prices have correlated well with WTI oil prices. The Company has entered into a limited number of NGL percentage of WTI oil prices derivatives to reduce the risk of volatility in NGL to WTI price differentials. The following table sets forth the volumes in Bbls under outstanding NGL derivative contracts and the weighted average Mont Belvieu-posted-prices or NGL component index prices per Bbl for those contracts as of December 31, 2009:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily NGL production derivatives (a):					
2010 – Swap contracts					
Volume (Bbl)	1,575	1,250	1,250	1,250	1,325
Price per Bbl	$ 49.00	$ 47.37	$ 47.38	$ 47.38	$ 47.86
2010 – Collar contracts					
Volume (Bbl)	2,000	2,000	2,000	2,000	2,000
Price per Bbl:					
Ceiling	$ 49.98	$ 49.98	$ 49.98	$ 49.98	$ 49.98
Floor	$ 41.58	$ 41.58	$ 41.58	$ 41.58	$ 41.58
2010 – Percentage contracts of WTI oil prices					
Volume (Bbl)	1,672	2,000	2,000	2,000	1,919
Percentage of WTI per Bbl	59%	60%	60%	60%	60%
2011 – Swap contracts					
Volume (Bbl)	750	750	750	750	750
Price per Bbl	$ 34.65	$ 34.65	$ 34.65	$ 34.65	$ 34.65
2011 – Collar contracts					
Volume (Bbl)	1,000	1,000	1,000	1,000	1,000
Price per Bbl:					
Ceiling	$ 50.93	$ 50.93	$ 50.93	$ 50.93	$ 50.93
Floor	$ 42.21	$ 42.21	$ 42.21	$ 42.21	$ 42.21
2012 – Swap contracts					
Volume (Bbl)	750	750	750	750	750
Price per Bbl	$ 35.03	$ 35.03	$ 35.03	$ 35.03	$ 35.03

Gas prices. All material physical sales contracts governing the Company's gas production have been tied directly or indirectly to regional index prices where the gas is produced. The Company uses derivative contracts to mitigate gas price volatility and reduce basis risk between NYMEX HH prices and actual index prices upon which the gas is sold. The following table sets forth the volumes in MMBtus under outstanding gas derivative contracts and the weighted average index prices per MMBtu for those contracts as of December 31, 2009:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Outstanding Average
Average daily gas production derivatives (a):					
2010 – Swap contracts					
Volume (MMBtu)	167,500	167,500	167,500	167,500	167,500
Price per MMBtu	$ 6.26	$ 6.26	$ 6.26	$ 6.26	$ 6.26
2010 – Collar contracts					
Volume (MMBtu)	40,000	40,000	40,000	40,000	40,000
Price per MMBtu:					
Ceiling	$ 7.19	$ 7.19	$ 7.19	$ 7.19	$ 7.19
Floor	$ 5.75	$ 5.75	$ 5.75	$ 5.75	$ 5.75
2010 – Collar contracts with short puts					
Volume (MMBtu)	95,000	95,000	95,000	95,000	95,000
Price per MMBtu:					
Ceiling	$ 7.94	$ 7.94	$ 7.94	$ 7.94	$ 7.94
Floor	$ 6.00	$ 6.00	$ 6.00	$ 6.00	$ 6.00
Short put	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
2010 – Basis swap contracts					
Volume (MMBtu)	215,000	215,000	215,000	215,000	215,000
Price per MMBtu	$ (0.77)	$ (0.77)	$ (0.77)	$ (0.77)	$ (0.77)
2011 – Swap contracts					
Volume (MMBtu)	77,500	77,500	77,500	77,500	77,500
Price per MMBtu	$ 6.35	$ 6.35	$ 6.35	$ 6.35	$ 6.35
2011 – Collar contracts with short puts					
Volume (MMBtu)	175,000	175,000	175,000	175,000	175,000
Price per MMBtu:					
Ceiling	$ 8.69	$ 8.69	$ 8.69	$ 8.69	$ 8.69
Floor	$ 6.36	$ 6.36	$ 6.36	$ 6.36	$ 6.36
Short put	$ 4.93	$ 4.93	$ 4.93	$ 4.93	$ 4.93
2011 – Basis swap contracts					
Volume (MMBtu)	120,000	120,000	120,000	120,000	120,000
Price per MMBtu	$ (0.62)	$ (0.62)	$ (0.62)	$ (0.62)	$ (0.62)
2012 – Swap contracts					
Volume (MMBtu)	2,500	2,500	2,500	2,500	2,500
Price per MMBtu	$ 6.77	$ 6.77	$ 6.77	$ 6.77	$ 6.77
2012 – Collar contracts with short puts					
Volume (MMBtu)	90,000	90,000	90,000	90,000	90,000
Price per MMBtu:					
Ceiling	$ 8.72	$ 8.72	$ 8.72	$ 8.72	$ 8.72
Floor	$ 6.25	$ 6.25	$ 6.25	$ 6.25	$ 6.25
Short put	$ 4.61	$ 4.61	$ 4.61	$ 4.61	$ 4.61
2012 – Basis swap contracts					
Volume (MMBtu)	40,000	40,000	40,000	40,000	40,000
Price per MMBtu	$ (0.47)	$ (0.47)	$ (0.47)	$ (0.47)	$ (0.47)
2013 – Swap contracts					
Volume (MMBtu)	2,500	2,500	2,500	2,500	2,500
Price per MMBtu	$ 6.89	$ 6.89	$ 6.89	$ 6.89	$ 6.89
2013 – Basis swap contracts					
Volume (MMBtu)	10,000	10,000	10,000	10,000	10,000
Price per MMBtu	$ (0.71)	$ (0.71)	$ (0.71)	$ (0.71)	$ (0.71)

(a) Subsequent to December 31, 2009 and through February 19, 2010, the Company entered into additional collar contracts with short puts for (i) 25,000 MMBtu per day of the Company's 2011 production with a ceiling price of $7.52 per MMBtu, a floor price of $6.00 per MMBtu and a short put price of $4.50 and (ii) 25,000 MMBtu per day of the Company's 2012 production with a ceiling price of $8.09 per MMBtu, a floor price of $6.00 per MMBtu and a short put price of $4.50 per MMBtu. The Company also entered into (i) additional swap contracts for 20,000 MMBtu per day and 10,000 MMBtu per day, respectively, of the Company's 2011 and 2013 production at an average price of $6.21 per MMBtu and $6.51 per MMBtu, respectively, and (ii) additional basis swap contracts for 36,849 MMBtu per day of the Company's 2010 production at an average price differential of $0.13 per MMBtu.

Interest rate. During August 2009 and January 2008, the Company entered into interest rate swap contracts. The August 2009 contracts were fixed-for-variable-rate swaps on $50 million notional amount of debt at a weighted average fixed annual rate of 3.09 percent. The August 2009 contracts had an effective start date of August 2009 and were scheduled to terminate in August 2014. The January 2008 contracts were variable-for-fixed-rate swaps on $400 million notional amount of debt at a weighted average fixed annual rate of 2.87 percent, excluding any applicable margins. The January 2008 interest rate swaps had an effective start date of February 2008, with $200 million terminating during February 2010 and $200 million during February 2011. During October 2009, the Company terminated the $50 million notional amount, fixed-for-variable rate swap contracts and $111 million notional amount of the variable-for-fixed rate swap contracts. The resulting gains and losses from the terminated contracts completely offset and had no impact on the Company's 2009 results of operations.

During the fourth quarter of 2009, the Company entered into $400 million notional amount of fixed-for-variable interest rate swaps at a weighted average fixed annual rate of 2.87 percent. The fourth quarter 2009 contracts had an effective start date of January 2010 and are scheduled to terminate in April 2016.

Hedge ineffectiveness. On February 1, 2009, the Company discontinued hedge accounting. As a result, the Company only recorded ineffectiveness during January 2009, which was nominal. During the years ended 2008 and 2007 the Company recorded net ineffectiveness losses of $500 thousand and $2.1 million, respectively. Hedge ineffectiveness represents the ineffective portions of changes in the fair values of the Company's cash flow hedging instruments. The primary causes of hedge ineffectiveness were changes in forecasted hedged sales volumes and variability in commodity price correlations.

Tabular disclosure of derivative fair value. All of the Company's derivatives were comprised of non-hedge derivatives as of December 31, 2009, except for $17.9 million of obligations on terminated hedges, and both hedge derivatives and non-hedge derivatives as of December 31, 2008. The following tables provide disclosure of the Company's derivative instruments:

Fair Value of Derivative Instruments as of December 31, 2009

	Asset Derivatives (a)		Liability Derivatives (a)	
Type	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
		(in thousands)		(in thousands)
Derivatives not designated as hedging instruments under ASC 815				
Commodity price derivatives	Derivatives - current	$ 66,442	Derivatives - current	$ 120,112
Interest rate derivatives	Derivatives - current	9,450	Derivatives - current	5,169
Commodity price derivatives	Derivatives - noncurrent	48,341	Derivatives - noncurrent	116,233
Interest rate derivatives	Derivatives - noncurrent	2,192	Derivatives - noncurrent	24,314
Total derivatives not designated as hedging instruments under ASC 815		126,425		265,828
Derivatives designated as hedging instruments under ASC 815 (b)				
Commodity price derivatives	Derivatives - current	—	Derivatives - current	17,913
Total derivatives designated as hedging instruments under ASC 815		—		17,913
Total derivatives		$ 126,425		$ 283,741

Fair Value of Derivative Instruments as of December 31, 2008

Type	Asset Derivatives (a) Balance Sheet Location	Asset Derivatives (a) Fair Value (in thousands)	Liability Derivatives (a) Balance Sheet Location	Liability Derivatives (a) Fair Value (in thousands)
Derivatives not designated as hedging instruments under ASC 815				
Commodity price derivatives	Derivatives - current	$ 3,606	Derivatives - current	$ 20,233
Commodity price derivatives	Derivatives - noncurrent	3,972	Derivatives - noncurrent	—
Total derivatives not designated as hedging instruments under ASC 815		7,578		20,233
Derivatives designated as hedging instruments under ASC 815				
Commodity price derivatives	Derivatives - current	57,367	Derivatives - current	24,195
Interest rate derivatives	Derivatives - current	—	Derivatives - current	6,484
Commodity price derivatives	Derivatives - noncurrent	68,622	Derivatives - noncurrent	17,165
Interest rate derivatives	Derivatives - noncurrent	—	Derivatives - noncurrent	3,419
Total derivatives designated as hedging instruments under ASC 815		125,989		51,263
Total derivatives		$ 133,567		$ 71,496

(a) Derivative assets and liabilities shown in the tables above are presented as gross assets and liabilities, without regard to master netting arrangements which are considered in the presentations of derivative assets and liabilities in the accompanying consolidated balance sheets.
(b) Represent derivative obligations under terminated hedge arrangements.

Derivatives in ASC 815 Cash Flow Hedging Relationships	Amount of Gain/(Loss) Recognized in AOCI on Effective Portion — Year Ended December 31, 2009	2008	2007
	(in thousands)		
Interest rate derivatives	$ (433)	$ (10,405)	$ —
Commodity price derivatives	13,407	228,607	(151,625)
Total	$ 12,974	$ 218,202	$ (151,625)

Derivatives in ASC 815 Cash Flow Hedging Relationships	Location of Gain (Loss) Reclassified from AOCI into Earnings	Amount of Gain (Loss) Reclassified from AOCI into Earnings — Year Ended December 31, 2009	2008	2007
		(in thousands)		
Interest rate derivatives	Interest expense	$ (6,835)	$ (1,168)	$ —
Commodity price derivatives	Oil and gas revenue	121,066	(355,563)	(55,322)
Total		$ 114,231	$ (356,731)	$ (55,322)

		Amount of Gain (Loss) Reclassified from AOCI into Earnings		
		Year Ended December 31,		
Derivatives in ASC 815 Cash Flow Hedging Relationships	**Location of Gain (Loss) Reclassified from AOCI into Earnings**	**2009**	**2008**	**2007**
			(in thousands)	

		Amount of Gain (Loss) Recognized in Earnings on Ineffective Portion		
		Year Ended December 31,		
Derivatives in ASC 815 Cash Flow Hedging Relationships	**Location of Gain (Loss) Recognized in Earnings on Ineffective Portion**	**2009**	**2008**	**2007**
			(in thousands)	
Commodity price derivatives	Derivative losses, net	$ —	$ (499)	$ (2,135)

		Amount of Gain (Loss) Recognized in Earnings on Derivative		
		Year Ended December 31,		
Derivatives Not Designated as Hedging Instruments under ASC 815	**Location of Gain (Loss) Recognized in Earnings on Derivative**	**2009**	**2008**	**2007**
			(in thousands)	
Interest rate derivatives	Derivative losses, net	$ (15,423)	$ —	$ —
Commodity price derivatives	Derivative losses, net	(180,134)	(9,649)	—
Total		$ (195,557)	$ (9,649)	$ —

AOCI - Hedging. The effective portions of deferred cash flow hedge gains and losses, net of associated taxes is reflected in AOCI-Hedging as of December 31, 2009 and 2008, and is being transferred to oil and gas revenue (for deferred commodity hedge gains and losses) and to interest expense (for deferred interest rate hedge gains and losses) in the same periods in which the hedged transactions are recorded in earnings. In accordance with the change to the MTM method of accounting on February 1, 2009, the Company recognizes changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which the changes occur.

As of December 31, 2009 and December 31, 2008, AOCI - Hedging represented net deferred gains of $51.0 million and $88.8 million, respectively. The AOCI - Hedging balance as of December 31, 2009 was comprised of $118.8 million of net deferred gains on the effective portions of discontinued commodity hedges, $6.2 million of net deferred losses on the effective portions of discontinued interest rate hedges, $30.3 million of associated net deferred tax provisions and $31.3 million of AOCI – Hedging attributable to noncontrolling interests. The AOCI - Hedging balance as of December 31, 2008 was comprised of $226.3 million of net deferred hedge gains on the effective portions commodity cash flow hedges, $12.4 million of net deferred losses on the effective portions of interest rate cash flow hedges (including $2.5 million of net deferred losses on terminated cash flow interest rate hedges), $80.4 million of associated net deferred tax provisions and $44.7 million of AOCI – Hedging attributable to noncontrolling interests. The $37.8 million decrease in net deferred hedge gains comprising AOCI - Hedging during the year ended December 31, 2009 was primarily attributable to the transfer of net deferred hedge gains to earnings, partially offset by deferred fair value gains during January 2009 and a decrease in AOCI – Hedging attributable to noncontrolling interests.

During the twelve months ending December 31, 2010, the Company expects to reclassify $89.0 million of AOCI – Hedging net deferred gains to oil and gas revenues and $3.6 million of AOCI – Hedging net deferred losses to interest expense. The Company also expects to reclassify $31.6 million of net deferred income tax provisions associated with hedge derivatives during the year ending December 31, 2010 from AOCI - Hedging to income tax expense.

Discontinued commodity hedges. Effective on February 1, 2009, the Company discontinued all of its commodity and interest rates hedges and began accounting for the associated derivatives using the MTM accounting method. Prior to

February 1, 2009, the Company periodically discontinued commodity hedges by terminating the derivative positions when the underlying commodity prices reached a point that the Company believed would be the high or low price of the commodity prior to the scheduled settlement of the open commodity position. This allowed the Company to lock in gains or minimize losses associated with the open hedge positions. At the time of hedge discontinuation, the amounts recorded in AOCI—Hedging were maintained and are being amortized to earnings over the periods the production was scheduled to occur.

For the years ending December 31, 2010, 2011 and 2012 the Company expects to reclassify deferred gains (losses) on discontinued commodity hedges of $89.0 million, $32.9 million and $(3.2) million, respectively, to oil and gas revenues.

NOTE K. Major Customers and Derivative Counterparties

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

The following United States purchasers individually accounted for ten percent or more of the Company's consolidated oil, NGL and gas revenues, including the revenues from discontinued operations and the results of commodity hedges, in at least one of the years in the three years ended December 31, 2009. The table provides the percentages of the Company's consolidated oil, NGL and gas revenues represented by the companies' purchases during the periods presented:

	Year Ended December 31,		
	2009	2008	2007
Plains Marketing LP	10%	13%	14%
Oneok Resources	5%	6%	11%
Occidental Energy Marketing, Inc.	7%	9%	11%
Enterprise Products Partners L.P.	6%	10%	7%

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures. The following table provides the Company's derivative assets and liabilities by counterparty as of December 31, 2009:

	Assets	Liabilities
	(in thousands)	
JP Morgan Chase	$ 27,115	$ 17,835
Societe Generale	14,386	39,144
Toronto Dominion	8,210	8,933
Calyon Corporate and Investment Bank	7,526	1,447
Barclays Capital	7,298	61,535
BNP Paribas	6,840	1,286
Credit Suisse	6,064	16,391
Deutsche Bank	5,486	27,495
Morgan Stanley	4,289	—
Citibank, N.A.	2,895	4,711
BMO Financial Group	1,077	17,993
Royal Bank of Scotland	524	—
J. Aron & Company	377	4,815
Wells Fargo Bank, N.A.	187	9,461
UBS	—	3,016
Wachovia	70	35,598
Total	$ 92,344	$ 249,660

NOTE L. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is employed in the calculations of asset retirement obligations. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations. The following table summarizes the Company's asset retirement obligation transactions during the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Beginning asset retirement obligations	$ 172,433	$ 208,184	$ 225,913
Liabilities assumed in acquisitions	—	2,237	4,751
New wells placed on production and changes in estimates (a)	40,778	23,637	91,067
Disposition of wells	(13,334)	—	(30,599)
Liabilities settled	(45,010)	(70,325)	(95,980)
Accretion of discount on continuing operations	11,012	7,903	6,115
Accretion of discount on discontinued operations	555	797	2,680
Currency translation	—	—	4,237
Ending asset retirement obligations	$ 166,434	$ 172,433	$ 208,184

(a) The change in the 2009 estimate is primarily due to (i) lower gas prices used to calculate proved reserves at December 31, 2009, which had the effect of shortening the economic life of wells and increasing the present value of future retirement obligations primarily in the Raton Basin, Hugoton and Uinta/Piceance gas fields and (ii) a $19.9 million increase in East Cameron facilities reclamation and abandonment estimates. The change in the 2008 estimate is primarily due to lower year-end prices for oil, NGL and gas being used to calculate proved reserves at December 31, 2008, which had the effect of shortening the economic life of many wells and increasing the present value of future retirement obligations. For the year ended

December 31, 2007, the increase includes $66.0 million in reclamation and abandonment estimate revisions for the East Cameron facilities. The East Cameron facilities were destroyed by Hurricane Rita and increases in associated reclamation and abandonments estimates are reflected in net hurricane activity in the accompanying consolidated statements of operations.

The Company records the current and noncurrent portions of asset retirement obligations in other current liabilities and other liabilities, respectively, in the accompanying consolidated balance sheets. As of December 31, 2009 and December 31, 2008, the current portions of the Company's asset retirement obligations were $13.9 million and $29.9 million, respectively.

NOTE M. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Alaskan Petroleum Production Tax credits (a)	$ 94,989	$ 18,636	$ 74,861
Gain on early extinguishment of debt	—	20,515	—
Interest income	2,025	3,312	3,038
Other income	2,020	1,440	3,210
Deferred compensation plan income	1,034	2,007	1,247
Foreign currency remeasurement and exchange gains (b)	894	8,058	6
Credit card rebates	864	1,178	975
Legal settlements	—	2,495	—
Sales and other tax refunds	480	—	3,730
Royalty obligation accrual adjustment	—	—	4,816
Total interest and other income	$ 102,306	$ 57,641	$ 91,883

(a) The Company earns Alaskan Petroleum Production Tax ("PPT") credits on qualifying capital expenditures. The Company recognizes income from PPT credits when they are realized through cash refunds or sales.

(b) The Company's operations in Africa periodically recognize monetary assets and liabilities in currencies other than their functional currencies. Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.

NOTE N. Asset Divestitures

During the years ended December 31, 2009, 2008 and 2007, the Company completed asset divestitures for net proceeds of $51.6 million, $292.9 million and $420.9 million, respectively. Associated therewith, the Company recorded losses on disposition of assets in continuing operations of $774 thousand, $381 thousand and $2.2 million during the years ended December 31, 2009, 2008 and 2007, respectively, and gains (losses) from the disposition of discontinued operations of $17.5 million, $(392) thousand and $100.2 million during the years ended December 31, 2009, 2008 and 2007, respectively. The following describes the significant divestitures:

Mississippi and Gulf of Mexico Shelf. In June 2009, the Company sold its Mississippi assets and in August 2009 completed the sale of substantially all of its shelf properties in the Gulf of Mexico for aggregate net proceeds of $23.6 million, resulting in a gain of $17.5 million. As a result of these divestitures, the Company reclassified the historical results of operations, comprehensive income and cash flows of its Mississippi and Gulf of Mexico shelf assets to discontinued operations.

Tunisian Cherouq Concession. During 2007, Enterprise Tunisiene d'Activities Petrolieres ("ETAP") exercised its right to participate with the Company as a 50 percent owner in the Company-operated Cherouq Concession. Associated therewith, ETAP became obligated to compensate the Company for $74.5 million of past Cherouq Concession costs, subject to ETAP's audit. During 2009, ETAP paid the Company $27.2 million of the Cherouq Concession past costs, which were classified in other noncurrent assets in the accompanying consolidated balance sheet at December 31, 2008. This cash receipt is classified as proceeds from disposition of assets in the accompanying consolidated statement of cash flows for the year ended December 31, 2009. ETAP has informed the Company that it intends to commence the past costs audit during the first quarter of 2010.

Derivative asset divestitures. During 2008, the Company terminated derivative assets prior to their contractual maturity dates. The accompanying consolidated statement of cash flows for the year ended December 31, 2008 includes $155.0 million of proceeds from disposition of assets attributable to these derivative terminations. Net gains attributable to these derivatives are included in AOCI – Hedging as of December 31, 2008. See Note J for additional information regarding the Company's derivative activities.

Canadian divestiture. In November 2007, the Company completed the sale of its Canadian subsidiaries for net proceeds of $525.7 million, resulting in a gain of $101.3 million. The net proceeds from the sale of the Canadian subsidiaries includes $132.8 million of proceeds that were deposited by the purchaser into the Company's Canadian escrow account pending receipt from the Canada Revenue Agency of appropriate tax certifications, which were received in January 2008. Accordingly, the accompanying consolidated statements of cash flows for the years ended December 31, 2008 and 2007, include approximately $132.0 million and $392.9 million of proceeds from disposition of assets, net of cash sold, respectively, related to the sale of the Canadian subsidiaries. As a result of this divestiture, the Company reclassified the historical results of operations, comprehensive income and cash flows of its Canadian assets to discontinued operations during 2007.

NOTE O. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Idle and terminated rig related costs (a)	$ 57,991	$ 54,539	$ 8,682
Well servicing operations (b)	12,437	3,289	3,245
Contingency and environmental accrual adjustments	7,796	12,449	14,750
Other	7,169	6,530	5,872
Transportation commitment loss (c)	6,839	—	—
Foreign currency remeasurement and exchange losses (d)	6,140	112	184
Bad debt expense (e)	4,356	30,119	5,119
Inventory impairment (f)	2,275	—	—
Colorado severance tax audit adjustment	—	5,730	—
Rig impairment	—	3,382	—
Postretirement benefit obligation revaluation	8	(177)	(10,561)
Total other expense	$ 105,011	$ 115,973	$ 27,291

(a) Represents idle drilling rig costs and costs incurred to terminate contractual drilling rig commitments prior to their contractual maturities.
(b) Represents idle well servicing costs.
(c) Primarily represents transportation contract deficiency payment obligations.
(d) The Company's current operations in Africa give rise to periodic recognition of monetary assets and liabilities in currencies other than their functional currencies (see Note B for information regarding the functional currencies of subsidiary entities). Associated therewith, the Company realizes foreign currency remeasurement and transaction gains and losses.
(e) Includes a $19.6 million SemGroup bad debt allowance in 2008. See Note I for more information.
(f) Represents impairment charges to reduce the carrying value of excess lease and well equipment and supplies inventories to their estimated net realizable values.

NOTE P. Income Taxes

The Company accounts for income taxes in accordance with the provisions of ASC Topic 740. The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state, local and foreign taxing authorities. The Company received tax refunds (net of tax payments) during 2009 of $42.6 million and made current and estimated tax payments (net of tax refunds) of $70.3 million and $29.5 million during 2008 and 2007, respectively. During 2009, the Company received $61.6 million of refunds as a result of carrying back 2007 and 2008 net operating losses. In November 2009, President Obama signed into law the *Worker, Homeownership, and Business Assistance Act of 2009,* which expanded the net operating loss carryback period from two years to five years and suspended certain loss utilization limitations. Pursuant to this new legislation, the Company filed an amended carryback claim requesting an additional $19.9 million refund. Payment is expected in March 2010. Also during 2009, pursuant to Tunisian law, the Company established an investment reserve equal to 20 percent of 2008 taxable profits on the Adam and Cherouq concessions and thereby reduced current taxes payable by $13.1 million with a corresponding offset to deferred income taxes in the Company's accompanying consolidated balance sheets. The investment reserve will be used to fund future drilling activity or pipeline infrastructure projects in Tunisia.

ASC Topic 740 requires that the Company continually assess both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs") and other deferred tax attributes in the United States, state, local and foreign tax jurisdictions will be utilized prior to their expiration. As of December 31, 2009 and 2008, the Company's valuation allowances (relating primarily to foreign tax jurisdictions) were $44.2 million and $37.5 million, respectively.

ASC Topic 740 also clarifies the accounting for uncertainty in income taxes recognized and prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2009, the Company had no unrecognized tax benefits. The Company's policy is to account for interest charges with respect to income taxes as interest expense and any penalties, with respect to income taxes, as other expense in the consolidated statements of operations. The Company files income tax returns in the U.S. federal jurisdiction, and various state and foreign jurisdictions. With few exceptions, the Company believes that it is no longer subject to examinations by tax authorities for years before 2004. In October 2009, the Internal Revenue Service ("IRS") concluded a limited examination of the Company's 2006 U.S. federal income tax return and is proposing to begin a full examination of the 2007 and 2008 tax years during the first quarter of 2010. In addition, the Company's 2004 through 2006 state income tax returns in Colorado are currently under audit. As of December 31, 2009, there are no proposed adjustments or uncertain positions in any jurisdiction that would have a significant effect on the Company's future results of operations or financial position. The Company's earliest open years in its key jurisdictions are as follows:

United States	2006
Various U.S. states	2004
Tunisia	2004
South Africa	2004

Pursuant to ASC Topic 740, the Company historically treated the undistributed earnings in South Africa as permanently reinvested and did not provide for a U.S. tax on such earnings. During 2007, the Company made the determination that it no longer had identifiable plans to reinvest these earnings in South Africa and accordingly began recording deferred taxes. The Company recorded a $4.8 million U.S. tax benefit during 2009 and $15.8 million and $18.9 million U.S. tax provisions during 2008 and 2007, respectively, for the results of operations of its South African subsidiaries.

The Company's income tax (provision) benefit and amounts separately allocated were attributable to the following items for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Income from continuing operations	$ 48,108	$ (201,091)	$ (105,923)
Income from discontinued operations	$ (50,440)	$ 2,189	$ 11,249
Changes in goodwill – tax benefits related to stock-based compensation	$ 124	$ 307	$ (961)
Changes in stockholders' equity:			
Net deferred hedge gains (losses)	$ 50,059	$ (213,151)	$ 35,266
Tax benefits related to stock-based compensation	$ 1	$ 367	$ 3,908

The Company's income tax (provision) benefit attributable to income from continuing operations consisted of the following for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Current:			
U.S. federal	$ 21,714	$ 19,954	$ 60,320
U.S. state	(10,010)	(665)	(331)
Foreign	(19,308)	(67,980)	(48,815)
	(7,604)	(48,691)	11,174
Deferred:			
U.S. federal	64,605	(118,909)	(125,524)
U.S. state	8,072	(423)	(6,576)
Foreign	(16,965)	(33,068)	15,003
	55,712	(152,400)	(117,097)
Income tax (provision) benefit	$ 48,108	$ (201,091)	$ (105,923)

Income (loss) from continuing operations before income taxes less net income attributable to the noncontrolling interests consists of the following for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
U.S. federal	$ (234,142)	$ 231,457	$ 290,056
Foreign	43,848	182,911	45,362
	$ (190,294)	$ 414,368	$ 335,418

Reconciliations of the United States federal statutory tax rate to the Company's effective tax rate for income from continuing operations are as follows for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
	(in percentages)		
U.S. federal statutory tax rate	35.0	35.0	35.0
State income taxes (net of federal benefit)	(0.5)	0.3	2.2
Foreign valuation allowances	(3.4)	3.2	6.9
Rate differential on foreign operations	(6.7)	6.1	4.8
West Africa exit (U.S. federal benefit)	—	—	(15.4)
South Africa expenditures uplift - 50% of development capital expenditures	—	(0.1)	(4.4)
South Africa earnings (U.S. federal income taxes)	2.5	3.7	5.3
Other	(1.6)	0.3	(2.8)
Consolidated effective tax rate	25.3	48.5	31.6

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities are as follows as of December 31, 2009 and 2008:

	December 31,	
	2009	2008
	(in thousands)	
Deferred tax assets:		
Net operating loss carryforwards	$ 136,676	$ 230,483
Alternative minimum tax credit carryforwards	—	21,714
Asset retirement obligations	55,553	56,225
Net deferred hedge losses	50,870	—
Other	45,520	55,436
Total deferred tax assets	288,619	363,858
Valuation allowances	(44,210)	(37,456)
Net deferred tax assets	244,409	326,402
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	(1,525,359)	(1,547,149)
State taxes and other	(162,833)	(195,829)
Net deferred hedge gains	—	(79,066)
Total deferred tax liabilities	(1,688,192)	(1,822,044)
Net deferred tax liability	$ (1,443,783)	$ (1,495,642)

At December 31, 2009, the Company had NOLs in the United States, South Africa and Tunisia for income tax purposes as set forth below, which are available to offset future regular taxable income in each respective tax jurisdiction, if any. Additionally, the Company has alternative minimum tax NOLs ("AMT NOLs") in the United States which are available to reduce future alternative minimum taxable income, if any. These carryforwards expire as follows:

	U.S.		South Africa	Tunisia
Expiration Date	NOL	AMT NOL	NOL	NOL
	(in thousands)			
2010	$ 19,964	$ 19,964	$ —	$ —
2028	248,386	32,314	—	—
Indefinite	—	—	44,662	69,182
	$ 268,350	$ 52,278	$ 44,662	$ 69,182

The 2010 U.S. NOLs and AMT NOLs are subject to Section 382 of the Internal Revenue Code and will become available to offset future regular or alternative minimum taxable income in 2010. Pursuant to GAAP, the Company's $136.7 million deferred tax asset related to regular NOL carryforwards at December 31, 2009 is net of $4.4 million of unrealized excess tax benefits from stock based compensation.

The Company's income tax (provision) benefit attributable to income from discontinued operations consisted of the following for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Current:			
U.S. state	$ (1,300)	$ —	$ —
Foreign	—	(300)	(4,915)
	(1,300)	(300)	(4,915)
Deferred:			
U.S. federal	(49,140)	2,489	14,889
Foreign	—	—	1,275
	(49,140)	2,489	16,164
Income tax (provision) benefit	$ (50,440)	$ 2,189	$ 11,249

NOTE Q. Net Income (Loss) Per Share Attributable To Common Stockholders

Effective January 1, 2009, the Company adopted the provisions of ASC 260 which outlines that share-based payments represent participating securities prior to vesting. In the calculation of basic net income (loss) per share attributable to common stockholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common stockholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so. The computation of diluted net income (loss) per share attributable to common stockholders reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. During periods in which the Company realizes a loss from continuing operations attributable to common stockholders, securities or other contracts to issue common stock would not be dilutive to net loss per share and conversion into common stock is assumed not to occur. In accordance with ASC 260, diluted net income (loss) per share is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented. For each of the three years in the period ended December 31, 2009, the two-class method of calculating the Company's diluted net income (loss) per share was more dilutive than the treasury stock method.

The Company's basic net income (loss) per share attributable to common stockholders is computed as (i) net income (loss) attributable to common stockholders, (ii) less participating share-based basic earnings (iii) divided by weighted average basic shares outstanding. The Company's diluted net income (loss) per share attributable to common stockholders is computed as (i) basic net income (loss) attributable to common stockholders, (ii) less participating share-based diluted earnings (iii) divided by weighted average diluted shares outstanding. The following table is a reconciliation of the Company's net income (loss) attributable to common stockholders to basic net income (loss) attributable to common stockholders and to diluted net income (loss) attributable to common stockholders for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Net income (loss) attributable to common stockholders	$ (52,106)	$ 210,020	$ 372,728
Participating share-based basic earnings	(196)	(2,745)	(6,142)
Basic net income (loss) attributable to common stockholders	(52,302)	207,275	366,586
Diluted adjustment to share-based earnings	—	9	21
Diluted net income (loss) attributable to common stockholders	$ (52,302)	$ 207,284	$ 366,607

The following table is a reconciliation of basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Weighted average common shares outstanding (a):			
Basic	114,176	117,462	120,158
Dilutive common stock options (b)	—	247	433
Contingently issuable - performance shares (b)	—	90	23
Convertible notes dilution (c)	—	148	—
Diluted	114,176	117,947	120,614

(a) In 2007, the Company's Board of Directors (the "Board") approved a $750 million share repurchase program of which $355.8 million remained available for purchase as of December 31, 2009. During 2009, the Company purchased $16.2 million of common stock pursuant to the program.

(b) Diluted earnings per share were calculated using the two-class method for the years ended December 31, 2009, 2008 and 2007. The following common stock equivalents were excluded from the diluted loss per share calculations for the year ended December 31, 2009 because they would have been anti-dilutive to the calculations: 173,915 outstanding options to purchase the Company's common stock and 223,969 performance shares.

(c) During January 2008, the Company issued $500 million of 2.875% Convertible Senior Notes. Weighted average common shares outstanding have been increased to reflect the dilutive effect that would have resulted if the 2.875% Convertible Senior Notes had qualified for and been converted during the year ended December 31, 2008. The 2.875% Convertible Senior Notes were not dilutive to the per share calculations of 2009.

NOTE R. Geographic Operating Segment Information

The Company has operations in only one industry segment, that being the oil and gas exploration and production industry; however, the Company is organizationally structured along geographic operating segments or regions. The Company has reportable continuing operations in the United States, South Africa, Tunisia and Other. Other is primarily comprised of 2007 operations in Equatorial Guinea and Nigeria.

During 2007, the Company sold its Canadian assets, which had a carrying value of $424.4 million. The results of operations of those properties have been reclassified as discontinued operations and, aside from costs incurred for oil and gas activities, are excluded from the geographic operating segment information provided below. See Note V for information regarding the Company's discontinued operations.

The following tables provide the Company's geographic operating segment data as of and for the years ended December 31, 2009, 2008 and 2007. Geographic operating segment income tax benefits (provisions) have been determined based on statutory rates existing in the various tax jurisdictions where the Company has oil and gas producing activities. The "Headquarters" table column includes income and expenses that are not routinely included in the earnings measures internally reported to management on a geographic operating segment basis.

	United States	South Africa	Tunisia	Headquarters	Consolidated Total
			(in thousands)		
Year Ended December 31, 2009:					
Revenues and other income:					
Oil and gas	$ 1,402,435	$ 57,217	$ 150,332	$ —	$ 1,609,984
Interest and other	—	—	—	102,306	102,306
Gain (loss) on disposition of assets, net	82	—	—	(856)	(774)
	1,402,517	57,217	150,332	101,450	1,711,516
Costs and expenses:					
Oil and gas production	345,885	5,507	28,934	—	380,326
Production and ad valorem taxes	98,371	—	—	—	98,371
Depletion, depreciation and amortization	536,075	64,802	21,802	28,881	651,560
Impairment of oil and gas properties	21,091	—	—	—	21,091
Exploration and abandonments	79,096	623	17,606	721	98,046
General and administrative	—	—	—	140,323	140,323
Accretion of discount on asset retirement obligations	—	—	—	11,012	11,012
Interest	—	—	—	173,361	173,361
Hurricane activity, net	17,313	—	—	—	17,313
Derivative losses, net	—	—	—	195,557	195,557
Other	54,223	—	3,768	47,020	105,011
	1,152,054	70,932	72,110	596,875	1,891,971
Income (loss) from continuing operations before income taxes	250,463	(13,715)	78,222	(495,425)	(180,455)
Income tax benefit (provision)	(92,671)	3,977	(44,029)	180,831	48,108
Income (loss) from continuing operations	$ 157,792	$ (9,738)	$ 34,193	$ (314,594)	$ (132,347)

	United States	South Africa	Tunisia	Headquarters	Consolidated Total
			(in thousands)		
Year Ended December 31, 2008					
Revenues and other income:					
Oil and gas	$ 1,893,362	$ 118,836	$ 215,383	$ —	$ 2,227,581
Interest and other	—	—	—	57,641	57,641
Gain on disposition of assets, net	513	—	—	(894)	(381)
	1,893,875	118,836	215,383	56,747	2,284,841
Costs and expenses:					
Oil and gas production	363,793	39,079	19,699	—	422,571
Production and ad valorem taxes	164,417	—	—	—	164,417
Depletion, depreciation and amortization	418,847	27,629	14,333	28,907	489,716
Impairment of oil and gas properties	89,753	—	—	—	89,753
Exploration and abandonments	189,728	143	37,629	—	227,500
General and administrative	—	—	—	141,922	141,922
Accretion of discount on asset retirement obligations	—	—	—	7,903	7,903
Interest	—	—	—	166,785	166,785
Hurricane activity, net	12,150	—	—	—	12,150
Derivative losses, net	—	—	—	10,148	10,148
Other	54,539	—	—	61,434	115,973
	1,293,227	66,851	71,661	417,099	1,848,838
Income (loss) from continuing operations before income taxes	600,648	51,985	143,722	(360,352)	436,003
Income tax benefit (provision)	(222,240)	(15,076)	(86,490)	122,715	(201,091)
Income (loss) from continuing operations	$ 378,408	$ 36,909	$ 57,232	$ (237,637)	$ 234,912

	United States	South Africa	Tunisia	Other	Headquarters	Consolidated Total
	(in thousands)					
Year Ended December 31, 2007						
Revenues and other income:						
Oil and gas	$ 1,507,227	$ 81,730	$ 106,341	$ —	$ —	$ 1,695,298
Interest and other	—	—	—	—	91,883	91,883
Gain (loss) on disposition of assets, net	844	—	—	—	(3,007)	(2,163)
	1,508,071	81,730	106,341	—	88,876	1,785,018
Costs and expenses:						
Oil and gas production	263,164	25,820	8,004	—	—	296,988
Production and ad valorem taxes	112,893	—	—	—	—	112,893
Depletion, depreciation and amortization	322,970	13,901	7,804	—	28,669	373,344
Impairment of oil and gas properties	5,687	—	—	20,528	—	26,215
Exploration and abandonments	230,966	276	16,743	30,672	—	278,657
General and administrative	—	—	—	—	129,735	129,735
Accretion of discount on asset retirement obligations	—	—	—	—	6,115	6,115
Interest	—	—	—	—	135,270	135,270
Hurricane activity, net	61,309	—	—	—	—	61,309
Derivative losses, net	—	—	—	—	2,135	2,135
Other	8,682	—	—	—	18,609	27,291
	1,005,671	39,997	32,551	51,200	320,533	1,449,952
Income (loss) from continuing operations before income taxes	502,400	41,733	73,790	(51,200)	(231,657)	335,066
Income tax benefit (provision)	(185,888)	(12,103)	(45,545)	—	137,613	(105,923)
Income (loss) from continuing operations	$ 316,512	$ 29,630	$ 28,245	$ (51,200)	$ (94,044)	$ 229,143

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Segment Assets:			
United States	$ 8,333,414	$ 8,524,622	$ 7,932,366
South Africa	179,000	241,619	294,491
Tunisia	266,342	299,168	216,221
Headquarters	88,509	96,376	163,467
Argentina	—	—	8,076
West Africa	—	—	2,360
Total consolidated assets	$ 8,867,265	$ 9,161,785	$ 8,616,981

NOTE S. Impairment of Oil and Gas Properties

The Company reviews its assets for impairment, including intangible assets, oil and gas properties and other long-lived assets, whenever events or circumstances indicate that their carrying values may not be recoverable. During the years ended December 31, 2009, 2008 and 2007, the Company recognized charges for the impairment of oil and gas properties in continuing operations of $21.1 million, $89.8 million and $26.2 million, respectively, and $14.5 million of impairment in discontinued operations during the year ended December 31, 2008.

United States impairment. During the first quarter of 2009 and the second half of 2008, declines in commodity prices provided indications that the carrying values of the Company's oil and gas properties in the Uinta/Piceance area and Mississippi may have been impaired. The Company's estimates of the undiscounted future cash flows attributed to the assets indicated that their carrying amounts were not expected to be recovered. Consequently, the Company recorded noncash charges during the first quarter of 2009 and the third quarter of 2008 of $21.1 million and $89.8 million, respectively, to reduce the carrying value of the Uinta/Piceance area oil and gas properties, and $14.5 million during the fourth quarter of 2008 to reduce the carrying value of its Mississippi assets. During 2009, the Company sold its Mississippi assets. The results of operations and impairment charge attributable to the Mississippi assets are included in discontinued operations, referred to in more detail in Note V. The impairment charges reduced the oil and gas properties' carrying values to their estimated fair values on those dates, represented by the estimated discounted future cash flows attributable to the assets, which were derived from Level 3 fair value inputs.

During the second quarter of 2007, the Company recorded a $5.7 million noncash impairment charge to reduce the carrying values of certain proved oil and gas properties located in Louisiana. The impairment charge reduced the carrying values of the assets to their estimated fair value.

The Company's primary assumptions in preparing the estimated discounted future net cash flows to be recovered from oil and gas properties are based on (i) proved reserves and risk-adjusted probable reserves, (ii) management's commodity price outlook, including assumptions as to inflation of costs and expenses, (iii) the estimated discount rate that would be used by purchasers to assess the fair value of the assets and (iv) future income tax expense attributable to the net cash flows.

Goodwill assessments. The Company's goodwill is attributable to a business combination that was completed in 2004 and is entirely attributable to United States reporting unit. The Company assesses its goodwill for impairment annually, during the third quarter using a July 1 assessment date, and also whenever facts or circumstances indicate that the carrying value of its goodwill may be impaired. The Company's assessments of goodwill during the third quarters of 2009 and 2008 indicated that it was not impaired. As a result of declines in commodity prices and a significant decline in the Company's market capitalization during the second half of 2008, the Company assessed whether the carrying value of the United States reporting unit's goodwill was impaired at December 31, 2008, March 31, 2009 and June 30, 2009 and concluded that it was not impaired based on those assessments. During 2009, commodity prices and the Company's market capitalization increased, providing indications that the carrying value of goodwill is not impaired.

The Company's assessments of goodwill for impairment include estimates of the fair value of its United States reporting unit and comparisons of those fair value estimates with the United States reporting unit's carrying value. The Company's estimates of the fair value of its United States reporting unit entail estimating the fair values of the reporting unit's assets and liabilities. The primary component of those assets and liabilities is comprised of the reporting unit's oil and gas properties, whose estimated values were based on the estimated discounted future net cash flows expected to be recovered from the properties. The Company's primary assumptions in preparing the estimated discounted future net cash flows expected to be recovered from the properties are based on (i) proved reserves and risk-adjusted probable reserves, (ii) management's price outlook, including assumptions as to inflation of costs and expenses, (iii) the estimated discount rate that would be used by purchasers to assess the fair value of the assets and liabilities attributable to the United States reporting unit and (iv) future income tax expense attributable to the net cash flows.

Due to the significant decline in the Company's market capitalization during the second half of 2008, the Company expanded its assessment of goodwill impairment to consider the fair value of the United States reporting unit as determined using both the previously described discounted future net cash flow approach and a market approach. The Company assessed market capitalization over the 30-day and 60-day periods prior to July 1, 2009, June 30, 2009, March 31, 2009 and December 31, 2008 and performed sensitivity valuations of the United States reporting unit's net assets based on varying valuation combinations of future discounted cash flow assumptions (including assessing future cash flows from proved properties only), market capitalization, control premiums, price inflation assumptions and discount rate assumptions. In the future, the Company will assess its goodwill for impairment whenever facts and circumstances indicate that it may be impaired, but no less often than annually, and such assessments may be affected by (i) additional United States reserve adjustments, both positive and negative, (ii) results of drilling activities, (iii) changes in management's outlook on commodity prices and costs and expenses, (iv) changes in the Company's market capitalization, (v) changes in the Company's weighted average cost of capital and (vi) changes in income taxes.

Nigerian impairment. In 2007, the Company withdrew from the production sharing contract relating to Block 320 offshore Nigeria and related agreements. As a part of this process, the Company disposed of its shares in a Nigeria subsidiary to an unaffiliated third party. In connection with the Company's withdrawal from Block 320 and the disposition of its shares in the Nigerian subsidiary, the Company recorded a $10.2 million noncash impairment charge during 2007.

Equatorial Guinea impairment. During the fourth quarter of 2007, the Company recorded a noncash impairment charge of $10.3 million to write off the Company's remaining basis in Block H in Equatorial Guinea. The charge was recorded in connection with an arbitration action that was active among the parties participating in the Block H prospect.

NOTE T. Volumetric Production Payments

During 2005, the Company sold 27.8 million barrels-of-oil-equivalent ("MMBOE") of proved reserves by means of three VPP agreements for net proceeds of $892.6 million, including the assignment of the Company's obligations under certain derivative hedge agreements. Proceeds from the VPPs were used to reduce outstanding indebtedness. The first VPP sold 58 billion cubic feet ("Bcf") of gas volumes over a 59 month term from February 2005 through December 2009. The second VPP sold 10.8 MMBbls of oil volumes over an expected seven-year term that began in January 2006. The third VPP sold 6.0 Bcf of gas volumes over a 32-month term from May 2005 through December 2007, and 6.2 MMBbls of oil volumes over an expected five-year term that began in January 2006.

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

The Company (i) removed the proved reserves associated with the VPPs, (ii) recognized VPP proceeds as deferred revenue which are being amortized on a unit-of-production basis to oil and gas revenues over the term of each VPP, (iii) retained responsibility for 100 percent of the production costs and capital costs related to VPP interests and (iv) no longer recognizes production associated with the VPP volumes.

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

	Gas	Oil	Total
		(in thousands)	
Deferred revenue at December 31, 2008	$ 49,435	$ 275,706	$ 325,141
Less: 2009 amortization	(49,435)	(98,470)	(147,905)
Deferred revenue at December 31, 2009	$ —	$ 177,236	$ 177,236

The remaining deferred revenue amounts will be recognized in oil revenues in the consolidated statements of operations as noted below, assuming the related VPP production volumes are delivered as scheduled (in thousands):

2010	$ 90,215
2011	44,951
2012	42,070
	$ 177,236

NOTE U. Insurance Claims

As a result of Hurricane Rita in September 2005, the Company's East Cameron facility, located in the Gulf of Mexico shelf, was destroyed. As of December 31, 2009, the Company estimates that it will cost approximately $6 million to complete the reclamation and abandonment of the East Cameron facility. The operations to reclaim and abandon the East Cameron facilities began in January 2007. The estimate of the remaining costs to reclaim and abandon the East Cameron facility is based upon an estimate by the Company.

The Company has spent $199.0 million on the reclamation and abandonment of the East Cameron facility through December 31, 2009. During 2009, 2008 and 2007, the Company recorded noncash obligation charges to net hurricane activity in the consolidated statements of operations for changes in estimates to reclaim and abandon the East Cameron facility of $19.9 million, $9.0 million and $66.0 million, respectively.

The Company filed a claim with its insurance providers regarding the loss at East Cameron. Under the Company's insurance policies, the East Cameron facility had the following coverage limits: (a) $14 million of scheduled property value for the platform, which was received in 2005, (b) $4 million of scheduled business interruption insurance after a deductible waiting period, which was received in 2006, (c) $100 million of well restoration and safety, in total, for all assets per occurrence and (d) $400 million for debris removal coverage for all assets per occurrence.

For the year ended December 31, 2009, the Company has received $40.7 million from its insurance providers related to debris removal, which reduced the Company's recorded $35.0 million receivable (which was classified in other noncurrent assets in the accompanying consolidated balance sheet at December 31, 2008) and credited net hurricane activity by $5.7 million. At the present, no recoveries have been reflected related to certain costs associated with plugging and abandonment and the well restoration and safety coverages. In 2007, the Company commenced legal actions against its insurance carriers regarding policy coverage issues, primarily related to debris removal, certain costs associated with plugging and abandonment, and the well restoration and safety coverages. The Company continues to expect that a substantial portion of the loss will be recoverable from insurance.

NOTE V. Discontinued Operations

During 2009, 2008 and 2007, the Company sold its interests in the following significant oil and gas assets:

Country	Description of Assets	Date Divested	Net Proceeds	Gain
			(in millions)	
Canada	Canadian assets	November 2007	$ 525.7(a)	$ 101.3
United States	Mississippi assets	June 2009	$ 0.1	$ 0.3
United States	Gulf of Mexico shelf properties	August 2009	$ 23.5	$ 17.2

(a) In November 2007, $132.8 million of the proceeds were deposited in a Canadian escrow account pending receipt from the Canada Revenue Agency of appropriate tax certifications which were received in January 2008. See Note E for additional information regarding the Canadian escrow account.

The Company has reflected the results of operations of the above divestitures as discontinued operations, rather than as a component of continuing operations. The following table represents the components of the Company's discontinued operations for the years ended December 31, 2009, 2008 and 2007:

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Revenues and other income:			
Oil and gas	$ 13,730	$ 49,751	$ 181,395
Interest and other (a)	119,346	2,176	1,885
Gain (loss) on disposition of assets, net (b)	17,491	(392)	100,178
	150,567	51,535	283,458
Costs and expenses:			
Oil and gas production	5,180	8,047	65,848
Production and ad valorem taxes	(27)	204	409
Depletion, depreciation and amortization (b)	3,863	22,130	48,555
Impairment of oil and gas properties (c)	—	14,516	—
Exploration and abandonments (b)	288	8,030	15,095
General and administrative	188	727	12,153
Accretion of discount on asset retirement obligations (b)	555	797	2,680
Interest	—	31	389
Other	—	2,499	6,345
	10,047	56,981	151,474
Income from discontinued operations before income taxes	140,520	(5,446)	131,984
Income tax benefit (provision):			
Current	(1,300)	(300)	(4,915)
Deferred (a)	(49,140)	2,489	16,164
Income from discontinued operations	$ 90,080	$ (3,257)	$ 143,233

(a) By letter dated November 6, 2009, the United States Department of Interior Minerals Management Service ("MMS") notified the Company that royalty relief was available for certain payments made on qualifying deepwater leases in the Gulf of Mexico. The royalty relief relates to a federal court ruling that the MMS did not have the authority to insert price thresholds into deepwater Outer Continental Shelf (OCS) leases that were issued pursuant to the OCS Deep Water Royalty Relief Act of 1995. Associated therewith, the Company applied for a refund of $119.3 million of excess royalties paid during the period from 2003 through 2005. The properties that were the source of these royalties were sold by the Company during 2006. Accordingly, the income recognized for the recovery of the excess royalties is classified as discontinued operations. The Company expects to receive the excess royalty refund, for which it recorded a $119.3 million receivable in accounts receivable – trade in the accompanying consolidated balance sheet as of December 31, 2009, during the first half of 2010.

(b) Represents the significant noncash components of discontinued operations.

(c) During 2008, the Company recognized $14.5 million of impairment to reduce the carrying value of its Mississippi assets that were sold during 2009. See Note S for additional information regarding impairment of oil and gas properties and other assets.

NOTE W. Subsequent Events

In accordance with SFAS 165, the Company has evaluated subsequent events through February 25, 2010, the date of issuance of the consolidated financial statements.

On January 21, 2010, the Company announced that it would call for redemption in cash its $6.1 million principal amount of outstanding 5.875% Senior Notes due 2012. The redemption date for the notes will be March 15, 2010. The Company is not aware of any other reportable subsequent events through February 25, 2010, except as disclosed in Note J.

Capitalized Costs

	December 31, 2009	December 31, 2008
	(in thousands)	
Oil and gas properties:		
Proved	$ 10,276,244	$ 10,167,220
Unproved	236,660	204,183
Capitalized costs for oil and gas properties	10,512,904	10,371,403
Less accumulated depletion, depreciation and amortization	(2,946,048)	(2,511,401)
Net capitalized costs for oil and gas properties	$ 7,566,856	$ 7,860,002

Costs Incurred for Oil and Gas Producing Activities (a)

	Property Acquisition Costs		Exploration Costs	Development Costs	Total Costs Incurred
	Proved	Unproved			
			(in thousands)		
Year Ended December 31, 2009:					
United States	$ 8,770	$ 80,088	$ 90,737	$ 255,538	$ 435,133
South Africa	65	—	623	(1,448)	(760)
Tunisia	—	—	19,931	17,470	37,401
Other	—	—	724	—	724
Total	$ 8,835	$ 80,088	$ 112,015	$ 271,560	$ 472,498
Year Ended December 31, 2008:					
United States	$ 87,482	$ 50,126	$ 322,086	$ 860,754	$ 1,320,448
South Africa	—	—	145	7,062	7,207
Tunisia	—	—	104,343	28,902	133,245
Total	$ 87,482	$ 50,126	$ 426,574	$ 896,718	$ 1,460,900
Year Ended December 31, 2007:					
United States	$ 331,526	$ 200,767	$ 335,778	$ 1,058,259	$ 1,926,330
Canada	82	3,620	32,160	64,584	100,446
South Africa	—	—	276	111,178	111,454
Tunisia	—	718	104,585	9,785	115,088
Other (b)	—	—	23,905	—	23,905
Total	$ 331,608	$ 205,105	$ 496,704	$ 1,243,806	$ 2,277,223

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

	Year Ended December 31, 2009	2008	2007
		(in thousands)	
Proved property acquisition costs	$ —	$ 2,237	$ 4,751
Exploration costs	1,068	749	1,499
Development costs	19,859	22,515	26,879
Total	$ 20,927	$ 25,501	$ 33,129

(b) Other is primarily comprised of activities in Nigeria and Equatorial Guinea.

UNAUDITED SUPPLEMENTARY INFORMATION
December 31, 2009, 2008 and 2007

Information about the Company's results of operations for oil and gas producing activities by geographic operating segment is presented in Note R of the accompanying notes to consolidated financial statements.

Reserve Quantity Information

The estimates of the Company's proved reserves as of December 31, 2009, 2008 and 2007 which were located in the United States, South Africa and Tunisia, were based on evaluations prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. Proved reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements.

During 2009, the SEC issued the Reserve Ruling and the FASB issued ASU 2010-03. The Reserve Ruling and ASU 2010-03 are effective for Annual Reports on Form 10-K for fiscal years ending on or after December 31, 2009. ASU 2010-03 aligns the provisions of ASC Topic 932 with the Reserve Ruling. Therefore, references to Reserve Ruling provisions also encompass the provisions of ASU 2010-03 and ASC Topic 932. The key provisions of the Reserve Ruling and ASU 2010-03 are as follows:

- Expanding the definition of oil- and gas-producing activities to include the extraction of saleable hydrocarbons, in the solid, liquid or gaseous state, from oil sands, coalbeds or other nonrenewable natural resources that are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction;
- Amending the definition of proved oil and gas reserves to require the use of an average of the first-day-of-the-month commodity prices during the 12-month period ending on the balance sheet date rather than the period-end commodity prices;
- Adding to and amending other definitions used in estimating proved oil and gas reserves, such as "reliable technology" and "reasonable certainty;"
- Broadening the types of technology that a registrant may use to establish reserves estimates and categories; and,
- Changing disclosure requirements and providing formats for tabular reserve disclosures.

The adoption of the Reserve Ruling and ASU 2010-03 reduced the Company's proved reserves by approximately 10 percent from what they would have been as of December 31, 2009. This change increased the Company's fourth quarter 2009 DD&A expense by $16.5 million, increased loss from continuing operations and net loss attributable to common stockholders by $10.4 million and increased diluted net loss attributable to common stockholders by $0.09 per share.

The Company reports all reserves held under concessions utilizing the "economic interest" method, which excludes the host country's share of proved reserves. Estimated quantities reported under the "economic interest" method are subject to fluctuations in the commodity prices of and recoverable operating expenses and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. The reserve estimates as of December 31, 2009, 2008 and 2007 utilized respective oil prices of $59.49, $43.00 and $95.45 per Bbl (reflecting adjustments for oil quality), respective NGL prices of $28.41, $20.07 and $56.13 per Bbl, and respective gas prices of $3.19, $4.63 and $6.12 per Mcf (reflecting adjustments for Btu content, gas processing and shrinkage).

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

The following table provides a rollforward of proved reserves by geographic area and in total for the years ended December 31, 2009, 2008 and 2007, as well as proved developed and undeveloped reserves by geographic area and in total as of the beginning and end of each respective year. Oil and NGL volumes are expressed in MBbls, gas volumes are expressed in MMcf and total volumes are expressed in thousands of barrels of oil equivalent ("MBOE").

UNAUDITED SUPPLEMENTARY INFORMATION
December 31, 2009, 2008 and 2007

	Year Ended December 31,											
	2009				2008				2007			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)(a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)(a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)(a)	Total (MBOE)
Total Proved Reserves:												
UNITED STATES												
Balance, January 1	294,357	154,535	2,917,029	935,063	291,381	159,710	2,903,055	934,933	258,195	148,530	2,685,961	854,385
Revisions of previous estimates	21,910	8,263	(335,006)	(25,660)	(8,577)	(6,077)	(92,794)	(30,120)	11,759	3,812	35,542	21,495
Purchases of minerals-in-place	—	—	—	—	2,425	2,045	58,758	14,263	9,584	10,094	184,478	50,424
Extensions and discoveries	10,413	1,229	18,865	14,785	17,196	5,841	202,284	56,751	18,647	4,045	131,277	44,571
Production (b)	(9,315)	(7,193)	(147,473)	(41,088)	(8,068)	(6,984)	(154,274)	(40,764)	(6,804)	(6,771)	(132,840)	(35,715)
Sales of minerals-in-place	(1,772)	—	(3,284)	(2,319)	—	—	—	—	—	—	(1,363)	(227)
Balance, December 31 (c)	315,593	156,834	2,450,131	880,781	294,357	154,535	2,917,029	935,063	291,381	159,710	2,903,055	934,933
CANADA												
Balance, January 1	—	—	—	—	—	—	—	—	1,861	338	173,509	31,117
Revisions of previous estimates	—	—	—	—	—	—	—	—	(110)	29	(18,778)	(3,210)
Extensions and discoveries	—	—	—	—	—	—	—	—	283	95	62,263	10,755
Production (b)	—	—	—	—	—	—	—	—	(98)	(136)	(16,295)	(2,950)
Sales of minerals-in-place	—	—	—	—	—	—	—	—	(1,936)	(326)	(200,699)	(35,712)
Balance, December 31	—	—	—	—	—	—	—	—	—	—	—	—
SOUTH AFRICA												
Balance, January 1	471	—	38,624	6,909	757	—	40,565	7,520	3,070	—	60,511	13,156
Revisions of previous estimates	(117)	—	(3,513)	(703)	594	—	1,804	894	(1,334)	—	(18,909)	(4,485)
Production (b)	(137)	—	(9,321)	(1,690)	(880)	—	(3,745)	(1,505)	(979)	—	(1,037)	(1,151)
Balance, December 31	217	—	25,790	4,516	471	—	38,624	6,909	757	—	40,565	7,520
TUNISIA												
Balance, January 1	13,587	—	24,104	17,604	17,850	—	20,794	21,314	4,977	—	7,846	6,284
Revisions of previous estimates	(1,678)	—	(615)	(1,780)	(3,376)	—	4,176	(2,679)	1,570	—	13,861	3,880
Extensions and discoveries	—	—	—	—	2,026	—	—	2,026	24,477	—	4	24,478
Production (b)	(2,383)	—	(609)	(2,485)	(2,261)	—	(866)	(2,405)	(1,403)	—	(917)	(1,557)
Sales of minerals-in-place	—	—	—	—	(652)	—	—	(652)	(11,771)	—	—	(11,771)
Balance, December 31	9,526	—	22,880	13,339	13,587	—	24,104	17,604	17,850	—	20,794	21,314
TOTAL												
Balance, January 1	308,415	154,535	2,979,757	959,576	309,988	159,710	2,964,414	963,767	268,103	148,868	2,927,827	904,942
Revisions of previous estimates	20,115	8,263	(339,134)	(28,143)	(11,359)	(6,077)	(86,814)	(31,905)	11,885	3,841	11,716	17,680
Purchases of minerals-in-place	—	—	—	—	2,425	2,045	58,758	14,263	9,584	10,094	184,478	50,424
Extensions and discoveries	10,413	1,229	18,865	14,785	19,222	5,841	202,284	58,777	43,407	4,140	193,544	79,804
Production (b)	(11,835)	(7,193)	(157,403)	(45,263)	(11,209)	(6,984)	(158,885)	(44,674)	(9,284)	(6,907)	(151,089)	(41,373)
Sales of minerals-in-place	(1,772)	—	(3,284)	(2,319)	(652)	—	—	(652)	(13,707)	(326)	(202,062)	(47,710)
Balance, December 31 (d)	325,336	156,834	2,498,801	898,636	308,415	154,535	2,979,757	959,576	309,988	159,710	2,964,414	963,767

(a) The proved gas reserves as of December 31, 2009, 2008 and 2007 include 310,463 MMcf, 360,340 MMcf and 290,599 MMcf, respectively, of gas that will be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.

(b) Production for 2009, 2008 and 2007 includes approximately 18,027 MMcf, 18,771 MMcf and 17,347 MMcf of field fuel, respectively. Also, for 2009, 2008 and 2007, production includes 328 MBOE, 571 MBOE and 3,734 MBOE of production associated with discontinued operations. See Note V for additional information.

(c) As of December 31, 2009 and 2008, the portions of the Company's United States proved reserves attributable to noncontrolling interests in Pioneer Southwest were as follows:

	Year Ended December 31,							
	2009				2008			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)
Noncontrolling interest in total proved reserves	10,539	3,741	15,448	16,854	4,311	1,680	6,966	7,152

(d) The adoption of the Reserve Ruling reduced the Company's total proved, proved developed and proved undeveloped oil and gas reserves by ten percent, 11 percent and nine percent, respectively, as of December 31, 2009, from what they would have been estimated under the previous definition of proved reserves. The ten percent reduction in total proved reserves that resulted from the adoption of the Reserve Ruling occurred as a result of 101 MMBOE of negative reserve revisions, primarily attributable to first-of-the-month average commodity prices during 2009 (used to measure proved reserves under the Reserve Ruling) being less than commodity prices at the end of 2009 (used to measure proved reserves prior to the Reserve Ruling), partially offset by 2 MMBOE of discoveries and extensions recorded using reliable technology and reasonable certainty provisions of the Reserve Ruling. The Company has no non-traditional sources of oil and gas reserves or investments accounted for under the equity method of accounting.

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The following table provides the Company's proved developed and proved undeveloped reserves as of January 1 and December 31, 2009, 2008 and 2007:

	Year Ended December 31,											
	2009				2008				2007			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)
Proved Developed Reserves:												
United States	119,964	91,456	1,907,719	529,373	136,571	101,501	1,976,080	567,419	116,987	94,827	1,805,974	512,809
Canada	—	—	—	—	—	—	—	—	1,716	338	117,672	21,665
South Africa	471	—	38,624	6,909	757	—	40,565	7,520	1,822	—	—	1,822
Tunisia	13,587	—	24,104	17,604	17,850	—	20,794	21,314	4,977	—	7,846	6,284
Balance, January 1	134,022	91,456	1,970,447	553,886	155,178	101,501	2,037,439	596,253	125,502	95,165	1,931,492	542,580
United States	135,568	93,015	1,671,052	507,092	119,964	91,456	1,907,719	529,373	136,571	101,501	1,976,080	567,419
South Africa	217	—	25,790	4,516	471	—	38,624	6,909	757	—	40,565	7,520
Tunisia	8,478	—	22,880	12,291	13,587	—	24,104	17,604	17,850	—	20,794	21,314
Balance, December 31	144,263	93,015	1,719,722	523,899	134,022	91,456	1,970,447	553,886	155,178	101,501	2,037,439	596,253

	Year Ended December 31,											
	2009				2008				2007			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)
Proved Undeveloped Reserves:												
United States	174,393	63,079	1,009,310	405,690	154,810	58,209	926,975	367,514	141,208	53,703	879,987	341,576
Canada	—	—	—	—	—	—	—	—	145	—	55,837	9,452
South Africa	—	—	—	—	—	—	—	—	1,248	—	60,511	11,334
Balance, January 1	174,393	63,079	1,009,310	405,690	154,810	58,209	926,975	367,514	142,601	53,703	996,335	362,362
United States	180,025	63,819	779,079	373,689	174,393	63,079	1,009,310	405,690	154,810	58,209	926,975	367,514
Tunisia	1,048	—	—	1,048	—	—	—	—	—	—	—	—
Balance, December 31	181,073	63,819	779,079	374,737	174,393	63,079	1,009,310	405,690	154,810	58,209	926,975	367,514

(a) As of December 31, 2009, the Company has 4,582 proved undeveloped well locations (all of which are expected to be developed within the five years ended December 31, 2014), representing a decrease of 395 proved undeveloped well locations (eight percent) since December 31, 2008. The decrease in proved undeveloped well locations during 2009 is primarily attributable to decreases in Raton basin well locations due to gas price revisions that rendered certain locations uneconomic under proved reserve pricing guidelines and 114 undeveloped well locations that were drilled and completed as developed wells during 2009, at a net cost of $76.3 million. During 2008, the Company initiated cost reduction initiatives that included minimizing drilling activities until margins improved as a result of commodity price increases and/or well cost reductions. Associated therewith, the Company significantly curtailed development expenditures during the first nine months of 2009. As a result of the successes realized from the aforementioned cost reduction initiatives and increases in 2009 oil prices, the Company implemented a plan to resume oil- and liquids-rich-gas-focused drilling activities during 2010 and has targeted its 2010 capital budget at $800 million to $900 million, excluding acquisitions, effects of asset retirement obligations, capitalized interest and geological and geophysical administrative costs. The Company's proved undeveloped well locations as of December 31, 2009 include 1,675 well locations that have remained undeveloped for five years or more. Approximately 93 percent of the Company's proved undeveloped well locations that remain undeveloped for five years or more are comprised of locations in the Spraberry field of West Texas in the Permian Basin. The Company recorded four proved undeveloped well locations and 2 MMBOE of proved undeveloped reserves in the United States under the reliable technology and reasonable certainty provisions of the Reserve Ruling, which would not have been recorded under the rules existing prior to the Reserve Ruling.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows ("Standardized Measure") is computed by applying commodity prices used in determining proved reserves (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of ten percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity derivative contracts. Utilizing the average of the first-day-of-the-month commodity prices during the 12-month period ending on December 31, 2009, held constant over each derivative contract's term, the net present value of the Company's derivative contracts, less associated estimated income taxes and discounted at ten percent, was an asset of $560.1 million at December 31, 2009.

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

The following tables provide the Standardized Measure by geographic area and in total as of December 31, 2009, 2008 and 2007, as well as a roll forward in total for each respective year:

	December 31,		
	2009	2008	2007
		(in thousands)	
UNITED STATES			
Oil and gas producing activities:			
Future cash inflows	$ 29,884,670	$ 27,779,303	$ 52,649,378
Future production costs	(12,527,319)	(11,605,862)	(14,562,540)
Future development costs	(4,623,978)	(4,840,604)	(4,252,134)
Future income tax expense	(3,468,973)	(2,831,642)	(11,265,645)
	9,264,400	8,501,195	22,569,059
10% annual discount for estimated timing of cash flows	(6,193,552)	(5,530,053)	(14,303,502)
Standardized measure of discounted future cash flows (a)	$ 3,070,848	$ 2,971,142	$ 8,265,557
SOUTH AFRICA			
Oil and gas producing activities:			
Future cash inflows	$ 147,022	$ 140,031	$ 365,145
Future production costs	(11,130)	(18,594)	(36,934)
Future development costs	(41,445)	(46,516)	(44,263)
Future income tax expense	(21,830)	(9,431)	(31,584)
	72,617	65,490	252,364
10% annual discount for estimated timing of cash flows	(712)	(629)	(37,108)
Standardized measure of discounted future cash flows	$ 71,905	$ 64,861	$ 215,256
TUNISIA			
Oil and gas producing activities:			
Future cash inflows	$ 750,078	$ 574,417	$ 1,892,519
Future production costs	(193,420)	(214,566)	(165,668)
Future development costs	(75,083)	(58,335)	(45,831)
Future income tax expense	(213,847)	(102,187)	(860,342)
	267,728	199,329	820,678
10% annual discount for estimated timing of cash flows	(79,927)	(47,945)	(284,607)
Standardized measure of discounted future cash flows	$ 187,801	$ 151,384	$ 536,071
TOTAL			
Oil and gas producing activities:			
Future cash inflows (b)	$ 30,781,770	$ 28,493,751	$ 54,907,042
Future production costs (b)	(12,731,869)	(11,839,022)	(14,765,142)
Future development costs(b) (c)	(4,740,506)	(4,945,455)	(4,342,228)
Future income tax expense (b)	(3,704,650)	(2,943,260)	(12,157,571)
	9,604,745	8,766,014	23,642,101
10% annual discount for estimated timing of cash flows (b)	(6,274,191)	(5,578,627)	(14,625,217)
Standardized measure of discounted future cash flows (b)	$ 3,330,554	$ 3,187,387	$ 9,016,884

(a) Includes $99.6 million attributable to a 38 percent noncontrolling interest in Pioneer Southwest for 2009 and $38.5 million attributable to a 32 percent noncontrolling interest in Pioneer Southwest in 2008.

(b) The adoption of the Reserve Ruling reduced the Company's Standardized Measure as of December 31, 2009 by $3.4 billion (or 50 percent), as compared to what the Company's Standardized Measure would have been under the rules and standards that existed prior to the Reserve Ruling. The decrease in Standardized Measure determined under the Reserve Ruling provisions is comprised of (i) a 36 percent decrease in future cash inflows (primarily attributable to first-of-the-month average commodity prices during 2009 being less than commodity prices at the end of 2009), (ii) a 22 percent decrease in future production costs (due to only a portion of the Company's production costs being correlated with commodity prices), (iii) a four percent decrease in future development costs, (iv) a 57 percent decrease in future income tax expense (due to lower future earnings from proved properties computed under the Reserve Ruling provisions) and (v) a 44 percent decrease in discounting of future net cash flows from proved reserves.

(c) Includes $453.5 million, $443.0 million and $471.5 million of undiscounted future asset retirement expenditures estimated as of December 31, 2009, 2008 and 2007, respectively, using current estimates of future abandonment costs. See Note L for corresponding information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2009	2008	2007
		(in thousands)	
Oil and gas sales, net of production costs	$ (1,018,798)	$ (2,037,654)	$ (1,462,189)
Net changes in prices and production costs	1,006,250	(9,019,111)	4,700,608
Extensions and discoveries	82,431	867,528	1,889,282
Development costs incurred during the period	183,936	632,359	661,956
Sales of minerals-in-place	(22,006)	(64,384)	(970,215)
Purchases of minerals-in-place	—	243,412	585,924
Revisions of estimated future development costs	(151,029)	(915,265)	(897,587)
Revisions of previous quantity estimates	(229,369)	(175,159)	322,470
Accretion of discount	385,681	1,336,401	660,755
Changes in production rates, timing and other	281,326	(375,321)	1,240,959
Change in present value of future net revenues	518,422	(9,507,194)	6,731,963
Net change in present value of future income taxes	(375,255)	3,677,697	(2,404,068)
	143,167	(5,829,497)	4,327,895
Balance, beginning of year	3,187,387	9,016,884	4,688,989
Balance, end of year	$ 3,330,554	$ 3,187,387	$ 9,016,884

PIONEER NATURAL RESOURCES COMPANY

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Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2009 and 2008:

	Quarter			
	First	Second	Third	Fourth
	(In thousands, except per share data)			
Year ended December 31, 2009:				
Oil and gas revenues:				
As reported	$ 373,837	$ 370,692	$ 409,969	$ 461,472
Less discontinued operations	(5,986)	—	—	—
Adjusted	$ 367,851	$ 370,692	$ 409,969	$ 461,472
Total revenues:				
As reported	$ 484,245	$ 459,343	$ 410,087	$ 463,690
Less discontinued operations	(5,986)	—	—	—
Adjusted	$ 478,259	$ 459,343	$ 410,087	$ 463,690
Total costs and expenses:				
As reported	$ 496,321	$ 591,316	$ 425,567	$ 486,109
Less discontinued operations	(7,479)	—	—	—
Adjusted	$ 488,842	$ 591,316	$ 425,567	$ 486,109
Net income (loss) attributable to common stockholders	$ (14,606)	$ (86,995)	$ (7,165)	$ 56,660
Net income (loss) attributable to common stockholders per share:				
Basic	$ (0.13)	$ (0.76)	$ (0.06)	$ 0.48
Diluted	$ (0.13)	$ (0.76)	$ (0.06)	$ 0.48
Year ended December 31, 2008:				
Oil and gas revenues:				
As reported	$ 558,476	$ 653,309	$ 612,200	$ 453,365
Less discontinued operations	(16,433)	(18,186)	(11,787)	(3,363)
Adjusted	$ 542,043	$ 635,123	$ 600,413	$ 450,002
Total revenues:				
As reported	$ 584,178	$ 665,689	$ 615,779	$ 472,642
Derivative gains, net reclassification	1,027	(711)	(1,104)	2,250
Less retrospective adoption of FSP APB 14-1	—	—	—	(2,733)
Less discontinued operations	(16,433)	(18,186)	(11,787)	(3,363)
Adjusted	$ 568,772	$ 646,792	$ 602,888	$ 468,796
Total costs and expenses:				
As reported	$ 369,111	$ 381,898	$ 603,431	$ 557,393
Derivative gains, net reclassification	1,027	(711)	(1,104)	2,251
Plus retrospective adoption of FSP APB 14-1	2,825	3,389	3,487	3,507
Less retrospective adoption of SFAS 160	(738)	(6,227)	(8,422)	(6,248)
Less discontinued operations	(8,587)	(8,102)	(10,529)	(26,407)
Adjusted	$ 363,638	$ 370,247	$ 586,863	$ 530,496
Net income (loss) attributable to common stockholders	$ 129,740	$ 158,829	$ (3,038)	$ (65,467)
Less retrospective adoption of FSP APB 14-1	(1,780)	(2,135)	(2,197)	(3,932)
Adjusted	$ 127,960	$ 156,694	$ (5,235)	$ (69,399)
Net income (loss) attributable to common stockholders per share:				
Basic as reported	$ 1.10	$ 1.34	$ (0.03)	$ (0.57)
Less retrospective adoption of FSP APB 14-1	(0.02)	(0.02)	(0.01)	(0.03)
Retrospective adoption of FSP EITF 03-6-1	0.01	(0.02)	—	—
Adjusted	$ 1.09	$ 1.30	$ (0.04)	$ (0.60)
Diluted as reported	$ 1.09	$ 1.32	$ (0.03)	$ (0.57)
Less retrospective adoption of FSP APB 14-1	(0.01)	(0.02)	(0.01)	(0.03)
Less retrospective adoption of FSP EITF 03-6-1	—	(0.01)	—	—
Adjusted	$ 1.08	$ 1.29	$ (0.04)	$ (0.60)

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

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. The Company's management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Securities Exchange Act of 1934 ("the Exchange Act"), the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this Report. Based on that evaluation, the principal executive officer and principal financial officer concluded that the Company's disclosure controls and procedures were effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, including that such information is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There have been no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2009 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

The Company's management, with the participation of its principal executive officer and principal financial officer, assessed the effectiveness as of December 31, 2009, of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting at a reasonable assurance level as of December 31, 2009, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2009. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Pioneer Natural Resources Company's (the "Company") internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Pioneer Natural Resources Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, Pioneer Natural Resources Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Pioneer Natural Resources Company as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2009 and our report dated February 26, 2010 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Dallas, Texas
February 26, 2010

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2010 and is incorporated herein by reference.

Item 11. Executive Compensation

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2010 and is incorporated herein by reference.

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

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about the Company's equity compensation plans as of December 31, 2009:

	Number of Securities to be Issued Upon Exercise of Outstanding Options (a)	Weighted Average Exercise Price of Outstanding Options	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in First Column) (b)
Equity compensation plans approved by security holders (c):			
Pioneer Natural Resources Company:			
2006 Long-Term Incentive Plan(d)	—	—	4,213,433
Long-Term Incentive Plan	218,130	$ 25.02	—
Employee Stock Purchase Plan	—	—	234,266
Predecessor plans	26,068	$ 13.43	—
	244,198	$ 23.79	4,447,699

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

(b) In May 2006, the stockholders of the Company approved the Long-Term Incentive Plan, which provides for the issuance of up to 9.1 million shares of common stock pursuant to awards, after giving effect to an amendment approved by the shareholders of the Company during May 2009. Awards under the Long-Term Incentive Plan can be in the form of stock options, stock appreciation rights, performance units, restricted stock and restricted stock units. No additional awards may be made under the prior Long-Term Incentive Plan. The number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan is based on the original authorized issuance of 750,000 shares less 515,734 cumulative shares issued through December 31, 2009. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of each of the Company's equity compensation plans.

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

(d) Remaining securities reflect the deduction of the maximum number of shares that could be issued pursuant to grants of performance units outstanding at December 31, 2009.

The remaining information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2010 and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2010 and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

The information required in response to this item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2010 and is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Listing of Financial Statements

Financial Statements

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

- Report of Independent Registered Public Accounting Firm
- Consolidated Balance Sheets as of December 31, 2009 and 2008
- Consolidated Statements of Operations for the Years Ended December 31, 2009, 2008 and 2007
- Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2009, 2008 and 2007
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2009, 2008 and 2007
- Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2009, 2008 and 2007
- Notes to Consolidated Financial Statements
- Unaudited Supplementary Information

(b) Exhibits

The exhibits to this Report required to be filed pursuant to Item 15(b) are included in the Company's Form 10-K filed with the SEC on February 26, 2010.

(c) Financial Statement Schedules

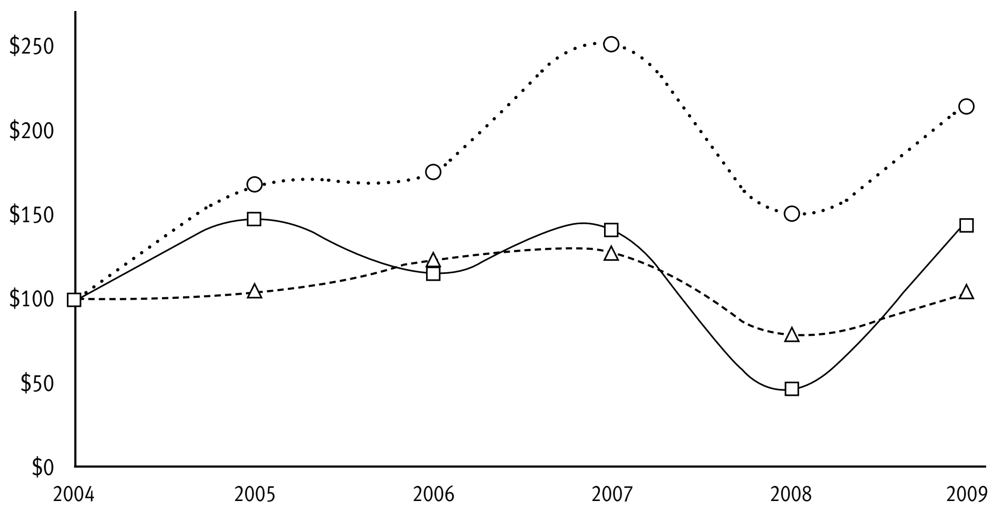
No financial statement schedules are required to be filed as part of this Report or they are inapplicable.

STOCK PERFORMANCE

The information included in the remainder of this document, including this "Stock Performance" section of the 2009 Annual Report, is not a part of Pioneer's Annual Report on Form 10-K for the fiscal year ended December 31, 2009, and shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission. Such information shall not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that Pioneer specifically incorporates such information.

The following graph and chart compare Pioneer's cumulative total stockholder return on common stock during the five-year period ended December 31, 2009, with cumulative total stockholder return during the same period for the Standard & Poor's 500 Index ("S&P 500 Index") and the Dow Jones U.S. Exploration and Production Index ("DJ E&P Index"), as prescribed by the SEC rules. The following graph and chart show the value, at December 31 in each of 2005, 2006, 2007, 2008 and 2009, of $100 invested at December 31, 2004, and assumes the reinvestment of all dividends:

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN AMONG PIONEER, THE S&P INDEX AND THE DJ E&P INDEX [(a)]



	Year ended December 31,					
	2004	2005	2006	2007	2008	2009
Pioneer Natural Resources Company	$100.00	$146.75	$114.30	$141.54	$ 47.16	$140.86
S&P 500 Index	$100.00	$104.91	$121.48	$128.16	$ 80.74	$102.11
DJ E&P Index	$100.00	$165.32	$174.20	$250.27	$149.86	$210.65

[(a)] Assumes $100 invested at December 31, 2004, in stock or index, including reinvestment of dividends.

SHAREHOLDER INFORMATION

STOCK EXCHANGE LISTING – COMMON STOCK
New York Stock Exchange: PXD

CORPORATE HEADQUARTERS
Pioneer Natural Resources Company
5205 N. O'Connor Blvd., Suite 200
Irving, TX 75039
(972) 444-9001
www.pxd.com

STOCK TRANSFER AGENT AND REGISTRAR
Communication concerning the transfer or exchange of shares, dividends, lost certificates or change of address should be directed to:

Continental Stock Transfer & Trust Company
17 Battery Place, 8th Floor
New York, NY 10004
(888) 509-5586
Internet Address: www.continentalstock.com
Email: pioneer@continentalstock.com

ANNUAL MEETING
The Annual Meeting of stockholders will be held at 5205 N. O'Connor Blvd, Suite 250, Irving, Texas 75039, on Friday, May 14, 2010, at 9:00 a.m. Central Time.

INFORMATION REQUESTS
To receive additional copies of the Annual Report on Form 10-K as filed with the SEC or to obtain other Pioneer publications, please contact:

Pioneer Natural Resources Company
Investor Relations
5205 N. O'Connor Blvd., Suite 200
Irving, TX 75039
(972) 969-3583
Email: ir@pxd.com

INVESTOR RELATIONS / MEDIA CONTACT
Shareholders, portfolio managers, brokers and securities analysts seeking information concerning Pioneer's operations or financial results are encouraged to contact Frank Hopkins, Vice President, Investor Relations at (972) 444-9001. Media inquiries should be directed to Susan Spratlen, Sr. Director, Corporate Communications and Public Affairs at (972) 444-9001.

CERTIFICATIONS
The CEO and CFO certifications required under Section 302 of the Sarbanes-Oxley Act were filed as exhibits to the most recently filed Form 10-K. In 2008, the Company submitted the CEO annual certification pursuant to Section 303A.12(a) of the NYSE Listed Company Manual.

OTHER OFFICE LOCATIONS

Pioneer Natural Resources UK Limited
David McManus, Executive Vice President, International Operations
1st Floor – Midas House
62 Goldsworth Rd.
Woking, Surrey GU21 6LQ
UK
Telephone: 44 1483 741710

Pioneer Natural Resources Alaska, Inc.
Kenneth H. Sheffield, Jr., President
700 G Street, Suite 600
Anchorage, AK 99501
USA
Telephone: (907) 277-2700

Pioneer Natural Resources South Africa (Pty) Limited
Marek Ranoszek, General Manager
21st Floor, #1 Thibault Square
1 Long Street
Cape Town 8001
RSA
Telephone: 27 21 425 5012

Pioneer Natural Resources Tunisia Ltd.
Edwin E. Hance, General Manager
Millenium
Rue du Lac de Côme
Les Berges du Lac
1053 – Tunis
Tunisia
Telephone: 216 71 168 800

BOARD OF DIRECTORS

Scott D. Sheffield
Chairman and
Chief Executive Officer

Thomas D. Arthur [2,4]
Former President and CEO
Havatampa Incorporated

Edison C. Buchanan [3,4]
Former Managing Director
Credit Suisse

Andrew F. Cates [3,4]
Managing Member
Value Acquisition Fund

R. Hartwell Gardner [2,4]
Retired Treasurer
Mobil Corporation

Andrew D. Lundquist [3,4]
Managing Partner
BlueWater Strategies LLC

Charles E. Ramsey, Jr. [1,3,4]
Retired Energy Industry Executive

Scott J. Reiman [3,4]
President
Hexagon Investments

Frank A. Risch [2,4]
Retired Vice President
and Treasurer
Exxon Mobil Corporation

Jim A. Watson [2,4]
Senior Counsel
Carrington, Coleman,
Sloman & Blumenthal, L.L.P.

Committee Membership:

[1] Lead Director
[2] Audit Committee
[3] Compensation and Management Development Committee
[4] Nominating and Corporate Governance Committee

OFFICERS

Scott D. Sheffield
Chairman and
Chief Executive Officer

Timothy L. Dove
President and
Chief Operating Officer

Mark S. Berg
Executive Vice President
and General Counsel

Chris J. Cheatwood
Executive Vice President,
Business Development
and Technology

Richard P. Dealy
Executive Vice President and
Chief Financial Officer

William F. Hannes
Executive Vice President,
South Texas Operations

Danny L. Kellum
Executive Vice President,
Permian Operations

David McManus
Executive Vice President,
International Operations

Jay P. Still
Executive Vice President,
Domestic Operations

Denny B. Bullard
Vice President,
Operations Services

Robert C. Hagens
Vice President, Land

Thomas C. Halbouty
Vice President,
Chief Information Officer and
Chief Technology Officer

Frank W. Hall
Vice President and
Chief Accounting Officer

Frank E. Hopkins
Vice President,
Investor Relations

Mark H. Kleinman
Vice President,
Corporate Secretary and
Chief Compliance Officer

Larry N. Paulsen
Vice President,
Administration and
Risk Management

Roger W. Wallace
Vice President,
Corporate Communications
and Government Affairs

PIONEER
NATURAL RESOURCES

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