PIONEER NATURAL RESOURCES CO
Form 10-K
February 27, 2014
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

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

For the fiscal year ended December 31, 2013

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, par value $.01	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 ý 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 ý

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 ý 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 ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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	ý	Accelerated filer	o
Non-accelerated filer	o (Do not check if a smaller reporting company)	Smaller reporting company	o

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

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	$19,865,703,072
Number of shares of Common Stock outstanding as of February 20, 2014	142,916,619

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the Definitive Proxy Statement for the Company's 2013 Annual Meeting of Shareholders to be held during May 2014 are incorporated into 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 six thousand cubic feet of gas to one 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.
- "Conway" means the daily average natural gas liquids components as priced in Oil Price Information Services ("OPIS") in the table "U.S. and Canada LP – Gas Weekly Averages" at Conway, Kansas.
- "DD&A" means depletion, depreciation and amortization.
- "Proved developed reserves" mean reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.
- "Field fuel" means gas consumed to operate field equipment (primarily compressors) prior to the gas being delivered to a sales point.
- "GAAP" means accounting principles that are generally accepted in the United States of America.
- "LIBOR" means London Interbank Offered Rate, which is a market rate of interest.
- "MBBL" means one thousand BBLs.
- "MBOE" means one thousand BOEs.
- "MCF" means one thousand cubic feet and is a measure of gas volume.
- "MMBBL" means one million BBLs.
- "MMBOE" means one million BOEs.
- "MMBTU" means one million BTUs.
- "MMCF" means one million cubic feet.
- "Mont Belvieu" means the daily average natural gas liquids components as priced in 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" mean 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 geoscience 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.

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(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 was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
(v) Existing economic 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.
- "Proved undeveloped reserves" means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
(iii) Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

- "U.S." means United States.
- "VPP" means volumetric production payment.
- "WTI" means West Texas intermediate, a light, sweet blend of oil produced from fields in western Texas.
- 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 (this "Report") contains forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "forecasts," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to the Company are intended to identify forward-looking statements, which are generally not historical in nature. 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 as and when made, 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.

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PIONEER NATURAL RESOURCES COMPANY

PART I

ITEM 1. BUSINESS

General

The Company is a large independent oil and gas exploration and production company with operations in the United States. Pioneer is a holding company whose assets consist of direct and indirect ownership interests in, and whose business is conducted substantially through, its subsidiaries. Pioneer's common stock is listed and traded on the NYSE under the ticker symbol "PXD."

The Company is a Delaware corporation formed in 1997. 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; and Midland, Texas. At December 31, 2013, the Company had 4,203 employees, 1,985 of whom were employed in other field and plant operations and 894 of whom were employed in vertical integration activities.

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 Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC.

Mission and Strategies

The Company's mission is to enhance shareholder investment returns through strategies that maximize Pioneer's long-term profitability and net asset value. The strategies employed to achieve this mission are predicated on maintaining financial flexibility, capital allocation discipline and enhancing net asset value through accretive drilling programs, joint ventures and acquisitions. These strategies are anchored by the Company's interests in the long-lived Spraberry/Wolfcamp oil field; the liquid-rich Eagle Ford Shale play; the Hugoton and West Panhandle fields; and the Raton gas field; which together have an estimated remaining productive life in excess of 40 years. Underlying these fields are 92 percent of the Company's total proved oil and gas reserves as of December 31, 2013.

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 and experienced personnel who make prudent capital investment decisions based on management direction, embrace technological innovation and are focused on price and cost management.

Petroleum industry. North American oil prices have been fairly consistent during the past three years despite the significant increase in United States oil production from unconventional shale plays. The growth in North American oil production has been offset by reduced oil imports, keeping supply and demand fairly balanced. Continued oil production growth in United States from unconventional shale plays is expected to outpace the decline in oil imports and increase oil price volatility. The growth of unconventional shale drilling has also substantially increased the supply of NGLs, resulting in a significant decline in NGL component prices as the supply of such products has grown. While more export facilities have been built and NGL exports are increasing, the overall United States demand for

NGL products has not kept pace with the remaining supply of such products; consequently, prices for NGL products have generally declined over the past three years. North American gas prices have remained

volatile and they trended lower from 2009 through 2012, but improved steadily throughout 2013. The decline in North American gas prices was primarily a result of significant discoveries of gas and associated gas reserves in United States gas, oil and liquid-rich shale plays, combined with the warmer than normal recent winters, which resulted in gas storage levels being at historically high levels, and minimal economic demand growth in the United States. The increases in gas prices during 2013 were primarily related to reduced drilling activity in gas shale plays and demand increases in the latter part of the year as a result of colder weather.

Oil prices continue to be primarily driven by world supply and demand fundamentals; however, recent increases in United States oil, NGL and gas production volumes from the Permian Basin, Eagle Ford, Bakken and Marcellus areas have been met with lower demand, higher storage levels and pipeline, gas plant and NGL fractionation infrastructure capacity limitations, which has led to a reduction in United States NYMEX oil, NGL and gas prices compared to international prices for similar commodities, including Brent oil prices.

Since 2010, the economies in the United States and certain other countries have continued to stabilize with resulting improvements in industrial demand and consumer confidence. However, other economies, such as those of certain European and Asian nations, continue to face economic struggles or slowing economic growth. While the outlook for a continued worldwide economic recovery remains cautiously optimistic, it is still uncertain; therefore, the sustainability of the recovery in worldwide demand for energy is difficult to predict. As a result, the Company believes it is likely that commodity prices will continue to be volatile during 2014.

Significant factors that will affect 2014 commodity prices include: the ongoing effect of economic stimulus initiatives; fiscal challenges facing the United States federal government and potential changes to the tax laws in the United States; continuing economic struggles in European and Asian nations; political and economic developments in North Africa and the Middle East; demand from 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; the capacity of United States refiners to absorb increasing domestic supplies of oil and condensate; potential export regulatory changes in the United States; the supply and demand fundamentals for NGLs in the United States and the pace at which export capacity grows; and overall North American gas supply and demand fundamentals, including refilling gas storage that is anticipated to be lower than normal at the end of the winter draw season.

Pioneer uses commodity derivative contracts to mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities and its net asset value. Although the Company has entered into commodity derivative contracts for a large portion of its forecasted production through 2015, 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 internal cash flows would be reduced for affected periods. 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 E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's open derivative positions as of December 31, 2013.

The Company. The Company's growth plan is primarily anchored by horizontal drilling in the Spraberry/Wolfcamp oil field located in West Texas and the liquid-rich Eagle Ford Shale field located in South Texas. Complementing these growth areas, the Company has oil and gas production activities and development opportunities in the Raton gas field located in southern Colorado, the Hugoton gas and liquid field located in southwest Kansas, the West Panhandle gas and liquid field located in the Texas Panhandle and the Edwards gas field located in South Texas. Combined, these assets create a portfolio of resources and opportunities that are well balanced and diversified among oil, NGL and gas, and that are also well balanced among long-lived, dependable production and lower-risk exploration and development opportunities. The Company has a team of dedicated employees who represent the professional disciplines and sciences that the Company believes are necessary to allow Pioneer to maximize the long-term profitability and net asset value inherent in its physical assets.

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. For the year ended December 31, 2013, the Company's production from continuing operations of 58.9 MMBOE, excluding field fuel usage, represented a 12 percent increase over production from continuing operations during 2012. Production, price and cost information with respect to the Company's properties for 2013, 2012 and 2011 is set forth in "Item 2. Properties — Selected Oil and Gas Information — Production, price and cost data."

Development activities. The Company seeks to increase its proved 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, 2013, the Company drilled 1,850 gross (1,655 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 $4.8 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, 2013 include proved undeveloped reserves and proved developed reserves that are behind pipe of 102.5 MMBBLs of oil, 41.9 MMBBLs of NGLs and 328.9 BCF of gas. The Company believes that its proved reserves represent a significant portfolio of development opportunities. 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 significant portfolio of lower-risk exploration opportunities that are expected to be evaluated and tested over the next decade and beyond. 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.
Integrated services. The Company continues to expand its integrated services to control drilling and operating costs and support the execution of its drilling program and operating activities. The Company has Company-owned fracture stimulation fleets totaling approximately 300,000 horsepower supporting drilling operations in the Spraberry/Wolfcamp and Eagle Ford Shale areas. The Company also owns other field service equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. In April 2012, Pioneer acquired a large U.S. industrial sands company, which was renamed Premier Silica (see Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the acquisition of Premier Silica). That acquisition secured a high-quality, low-cost and logistically advantaged brown sand supply for Pioneer to use for its growing fracture stimulation requirements in the Spraberry field.
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 provide future exploration/exploitation opportunities. During 2013, 2012 and 2011, the Company spent $76.0 million, $157.5 million and $131.9 million, respectively, to purchase primarily undeveloped acreage for future exploitation and exploration activities.
In addition, on December 17, 2013, the Company completed the acquisition of all of the outstanding common units of Pioneer Southwest not already owned by the Company, through a merger of a wholly-owned subsidiary of the Company into Pioneer Southwest, the result of which was that Pioneer Southwest became a wholly-owned subsidiary of the Company. The Pioneer Southwest merger was effected pursuant to an Agreement and Plan of Merger dated August 9, 2013, as amended on October 25, 2013 (as amended, the "Merger Agreement"), and was approved by the holders of the common units of Pioneer Southwest at a special meeting held on December 17, 2013. Pursuant to the Merger Agreement, all of the common units outstanding as of the closing of the merger were canceled and converted into the right to receive 0.2325 of a share of common stock of the Company per common unit. In December 2013 the Company issued an aggregate of 3.96 million shares of its common stock to Pioneer Southwest unitholders. The merger is expected to facilitate the Company's plans to fully and optimally develop the Company's Spraberry/Wolfcamp properties in the Midland Basin in West Texas utilizing horizontal drilling and is expected to enhance the Company's organizational, operational and administrative efficiencies.
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 and discontinued operations. 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.

During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer's Alaska subsidiary, representing all the Company's net assets in Alaska ("Pioneer Alaska"). The sale of Pioneer Alaska continues to be subject to ongoing negotiations and certain other conditions, such as governmental approvals and buyer's arrangement of financing. Associated with the planned sale of Pioneer Alaska, the Company recorded a noncash impairment charge of $539.8

million during December 2013 to reduce the carrying value of Pioneer Alaska to its estimated fair value less costs to sell of $350.6 million. The Company has classified Pioneer Alaska assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and has reported Pioneer Alaska's historical results of operations, and the related impairment loss, as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

During the fourth quarter of 2013, the Company also committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. The plan is expected to result in the sale of the Barnett Shale net assets during 2014. Associated with the plan to sell the Company's net assets in the Barnett Shale field, the Company recorded a noncash impairment charge of $189.5 million during December 2013 to reduce the carrying value of the Barnett Shale field net assets to their estimated fair value less costs to sell. The Company has classified Barnett Shale assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and has reported Barnett Shale historical results of operations, and the related impairment loss, as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

During December 2013, the Company committed to a plan to sell its majority interest in Sendero Drilling Company, LLC ("Sendero"), the Company's vertical drilling rig subsidiary, to Sendero's minority interest owner for $31.0 million, subject to negotiating a definitive sales agreement and the buyer completing its financing arrangements. Associated with the planned sale of Sendero, the Company recorded a noncash loss of $25.5 million during December 2013 to reduce the carrying value of Sendero's net assets to their estimated fair value. As part of the sales negotiations, the Company plans to commit to lease 12 Sendero rigs through December 31, 2015 and to lease eight Sendero rigs in 2016. The Company has classified Sendero assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013.

The Company's plans to sell Pioneer Alaska, the Barnett Shale net assets and Sendero are in various stages of marketing or negotiation. No assurance can be given that the sales will be completed in accordance with the Company's plans.

In January 2013, the Company signed an agreement with Sinochem Petroleum USA LLC ("Sinochem"), a U.S. subsidiary of the Sinochem Group, an unaffiliated third party, to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field for consideration of $1.8 billion. In May 2013, the Company completed the sale to Sinochem for net cash proceeds of $623.8 million, resulting in a gain of $181.3 million related to the unproved property interests conveyed to Sinochem. Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play.

During December 2011, the Company committed to a plan to exit South Africa and initiated a process to divest its net assets in South Africa ("Pioneer South Africa"). During the first quarter of 2012, the Company agreed to sell Pioneer South Africa to an unaffiliated third party, effective January 1, 2012, for $60.0 million of cash proceeds before normal closing and other adjustments, and the buyer's assumption of certain liabilities of the Company's South Africa subsidiaries. In August 2012, the Company completed the sale of Pioneer South Africa for net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a gain of $28.6 million. The Company classified Pioneer South Africa's results of operations as discontinued operations, net of tax in the accompanying consolidated statements of operations.

In February 2011, the Company sold 100 percent of the Company's share holdings in Pioneer Natural Resources Tunisia Ltd. and Pioneer Natural Resources Anaguid Ltd. (referred to in the aggregate as "Pioneer Tunisia") to an unaffiliated third party for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a gain of $645.2 million. The Company classified the results of operations of Pioneer Tunisia as discontinued operations, net of tax in the accompanying consolidated statements of operations.

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. See Note C 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. Also see "Item1A. Risk Factors - The Company's ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond its control, and in certain cases the Company may be required to retain liabilities for certain matters" for discussion of risk factors associated with the completion of divestitures.

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 an index or spot price, price regulations, distance from the well to the pipeline, commodity quality and prevailing supply and demand

conditions. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional discussion of operations and price risk.

Significant purchasers. During 2013, the Company's significant purchasers of oil, NGLs and gas were Plains Marketing LP (26 percent), Enterprise Products Partners L.P. (12 percent) and Occidental Energy Marketing Inc. (12 percent). The Company believes that the loss of a significant purchaser or an inability to secure adequate pipeline, gas plant and NGL fractionation infrastructure in its key producing areas could have a material adverse effect on its ability to sell its oil, NGL and gas production. See "Item 1A. Risk Factors" and Note L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about significant customer and infrastructure capacity risks.

Derivative risk management activities. The Company primarily 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 or consumes, (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. The Company accounts 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 E 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 gains and losses during 2013, 2012 and 2011, as well as the Company's open commodity derivative positions at December 31, 2013.

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 acquiring 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. Some 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 would have an adverse effect on the market price and liquidity of the Company's common stock. Compliance with some of these rules and regulations is costly, and regulations are subject to change or reinterpretation.

Environmental and occupational health and safety matters. The Company's operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, worker health and safety,

and the discharge of materials into the environment. Numerous governmental entities, including the U.S. Environmental Protection Agency (the "EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions to achieve and maintain compliance and imposing sanctions, including administrative, civil and criminal penalties, for any failure to comply.

These laws and regulations may, among other things:

- require the acquisition of various permits before drilling or other regulated activity commences;
- enjoin some or all of the operations of facilities deemed in noncompliance 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;
- impose specific criteria addressing worker protection;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and
- impose substantial liabilities for pollution resulting from operations.

These laws 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 U.S. Congress, state legislatures and federal and state regulatory agencies frequently revise environmental laws and regulations, and the 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 drilling, completion, construction or water management activities, or waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant effect on the Company's capital and operating costs.

The following is a summary of some of the more significant laws and regulations to which the Company's business operations are or may be subject.

Waste handling. The federal 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 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. In the course of its operations, the Company 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. 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, with respect to NORM, the treatment, storage and disposal of NORM waste, the management of waste piles, containers and tanks containing NORM and restrictions on the uses of land with NORM contamination.

Comprehensive Environmental Response, Compensation, and Liability Act. The federal Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, and analogous state laws impose 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. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. 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 petroleum 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 recycling or disposal. In addition, some of the Company's properties have been operated by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company's control. Certain of these properties have had historical petroleum spills or releases. All of such 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. If a surface spill or release were to occur, the Company expects that it would be controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions and by using the Company's spill prevention, control and countermeasure ("SPCC") plans or other spill or emergency contingency plans that it maintains in accordance with EPA requirements.

Water discharges and use. The federal Water Pollution Control Act, also known as 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 and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the 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. SPCC planning 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 noncompliance 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. If an oil spill subject to the requirements of OPA were to occur at a Company property, the Company expects that it would be controlled, contained and remediated in accordance with the applicable requirements of OPA and by using the Company's OPA spill response plan together with the assistance of trained first responders and any oil spill response contractor that the Company would have engaged pursuant to OPA to address such oil spills.

Operations associated with the Company's properties also produce wastewaters that are disposed by injection in underground wells. These injection wells are regulated by the federal 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 substantially 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. For example, in some areas of Texas, there has been concern that certain formations into which disposal wells are injecting produced waters could become over-pressured after many years of injection, and the governing Texas regulatory agency is reviewing the data to determine whether any action is necessary to address this issue. If the Texas state agency were to decline to issue permits for new injection wells into the formations currently utilized by the Company, the Company may be required to seek alternative methods of disposing of produced waters, including injecting into deeper formations, which could increase its costs. In addition, in response to recent seismic events near underground injection wells used for the disposal of wastewaters, some federal and state agencies have been investigating whether such wells have caused increased seismic activity. It is possible that federal or state agencies will seek to regulate more stringently the underground injection of oil and gas wastewaters as a result of these events. Nevertheless, the Company is not aware of any imminent actions by federal or state agencies that would affect its use or operation of underground injection wells due to the concern about seismic activity.

The Company also uses hydraulic fracturing techniques in virtually all of its drilling and completion programs and development of its properties is dependent on the Company's ability to hydraulically fracture the producing formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions, but, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the SDWA Underground Injection Control Program and published final permitting guidance in February 2014 addressing the performance of such activities. In 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and in its Semi-annual Regulatory Agenda published in July 2013, the agency continues to project the future issuance of an Advance Notice of Proposed Rulemaking that would seek public input on the design and scope

of such disclosure regulations. The EPA published final rules under the federal Clean Air Act ("CAA") that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 and performing reduced emission completions, also known as "green completions," with or without combustion devices, on or after January 1, 2015. Also, in May 2013, the federal Bureau of Land Management (the "BLM") published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. In addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process.

Certain states in which the Company operates, including Colorado and Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure and well-construction requirements on

hydraulic fracturing operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. The Company believes that it follows applicable standard industry practices and legal requirements for groundwater protection in its hydraulic fracturing activities. Nonetheless, in the event federal, state or local restrictions are adopted in areas where the Company is currently conducting, or in the future plans to conduct operations, the Company may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development or production activities, and be limited or precluded in the drilling of wells or in the amounts that the Company is ultimately able to produce from its reserves.

Certain governmental reviews were recently conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and a draft report is expected to be available for public comments and peer review in 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and is expected to propose these standards in 2014. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

The water produced by the Company's CBM operations also may be subject to the state laws and regulations of 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. Nevertheless, in 2009, the Colorado Supreme Court affirmed a state court holding 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 Colorado legislature and state agency adopted laws and regulations in response to this ruling. These and other resulting changes in the regulation of water produced from CBM operations may have an adverse effect on the costs of doing business and the ability to expand operations by the Company or other CBM producers.

Air emissions. 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 may impose their own air emissions limitations, which may be more stringent than the federal standards imposed by the EPA. Federal and state regulatory agencies can also impose administrative, civil and criminal penalties for noncompliance with air permits or other requirements of the CAA and associated state laws and regulations. The adoption of laws, regulations, orders or other legally enforceable mandates governing oil and gas drilling and operating activities in the areas where the Company conducts business that result in more stringent drilling or operating conditions or limit or prohibit the drilling of new wells for any extended period of time could increase the Company's costs or reduce its production, which could have a material adverse effect on the Company's results of operations and cash flows.

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 oil and gas exploration and production operations. For example, in 2012, the EPA published final rules under the CAA that subject oil and gas production, processing, transmission and storage operations to regulation under the New

Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. With regard to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flowback emissions to a gathering line or capture and combust flowback emissions using a combustion device, such as a flare. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, on or after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, beginning as early as October 15, 2013. Compliance with these requirements could increase the Company's costs of development and production, which costs could be significant.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of the Company's operations are conducted in areas where protected species or their habitats are known to exist. In these areas, the Company may be obligated to develop and implement plans to avoid potential adverse effects to protected species and their habitats, and the Company may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when the Company's operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where the Company performs activities could result in increased costs or limitations on the Company's ability to perform operations and thus have an adverse effect on the Company's business.

Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on the potential listing of numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where the Company operates could cause the Company to incur increased costs arising from species protection measures or could result in limitations on the Company's drilling and production activities that could have an adverse effect on the Company's ability to develop and produce its proved reserves.

Activities on Federal Lands. Oil and gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, the Company has minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay or limit, or increase the cost of, the development of oil and gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects.

Occupational health and safety. The Company's operations are subject to the requirements of OSHA and comparable state statutes. These laws and the related regulations strictly govern the protection of the health and safety of employees. The OSHA 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. In addition, the Company's sand mining operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. The Company believes that it is in substantial compliance with these applicable standards and with OSHA and comparable requirements.

Climate change. In 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public 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. Based on these findings, the EPA has adopted regulations under the CAA establishing Title V and Prevention of Significant Deterioration ("PSD") permitting requirements for large sources of GHGs. The Company could become subject to these permitting requirements and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that the Company may seek to construct in the future if they would otherwise emit large volumes of GHGs. The EPA has also adopted rules requiring the reporting of GHG emissions on an annual basis from specified GHG emission sources in the United States, including certain oil and gas production facilities, which includes certain of the Company's facilities. The Company is monitoring GHG emissions

from its operations in accordance with these GHG emissions reporting rules and believes its monitoring activities are in substantial compliance with applicable reporting obligations.

While the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the United States, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If the U.S. Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on the Company's operations.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would affect the Company's business, any such future laws and regulations could require the Company to incur increased

operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. Any such legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for the oil and gas the Company produces. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Company's business, financial condition and results of operations.

Some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on the Company's financial condition and results of operations.

Other regulation of the oil and gas industry. The oil and gas industry is regulated by numerous 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 federal and state departments and agencies 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 production, the Company believes that 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.

Development and production. Development and production operations are subject to various types of regulation at 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 method and ability to fracture stimulate 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 development 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 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. Federal and state regulations govern the price and terms for access to gas pipeline transportation. Intrastate gas pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies. The interstate transportation and sale 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"). FERC endeavors to make gas transportation more accessible to gas buyers and sellers on an open-access and non-discriminatory basis.

Pursuant to the Energy Policy Act of 2005 ("EPAct 2005") it is unlawful for "any entity," including producers such as the Company, that are otherwise not subject to FERC's jurisdiction under the Natural Gas Act (the "NGA"), 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 FERC, in contravention of rules prescribed by FERC. FERC's rules implementing this provision make it unlawful, in connection with the purchase or sale of gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of 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 FERC authority to impose civil penalties of up to $1.0 million per day for each violation of the NGA or the Natural Gas Policy

Act of 1978. The anti-manipulation rule applies to activities of entities not otherwise subject to FERC's jurisdiction 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, FERC issued a final rule on the annual gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, 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 of physical gas in the previous calendar year must annually report such sales and purchases to FERC on Form No. 552 on May 1 of each year. Form No. 552 contains aggregate volumes of gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state regulatory bodies and the courts. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on its operations. The Company does not believe that it will be affected by any action taken in a materially different way than other gas producers, gatherers and marketers with which it competes.

Natural gas processing. The Company's gas processing operations are not subject to FERC or state regulation. There can be no assurance that the Company's processing operations will continue to be exempt from regulation in the future. However, although the processing facilities may not be directly related, other laws and regulations may affect the availability of gas for processing, such as state regulation of production rates and maximum daily production allowable from gas wells, which could impact the Company's processing business.

Gas gathering. Section 1(b) of the NGA exempts gas gathering facilities from FERC's jurisdiction. The Company believes that its gathering facilities meet the traditional tests FERC has used to establish a pipeline system's status as a non-jurisdictional gatherer. There is, however, no bright-line test for determining the jurisdictional status of pipeline facilities. Moreover, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of litigation from time to time, so the classification and regulation of some of the Company's gathering facilities may be subject to change based on future determinations by FERC and the courts. Thus, the Company cannot guarantee that the jurisdictional status of its gas gathering facilities will remain unchanged.

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 affected by the rates charged by these third parties for gathering services. To the extent that changes in federal or state regulation affect the rates charged for gathering services, the Company also may be affected by these changes. Accordingly, the Company does not anticipate that the Company would be affected any differently than similarly situated gas producers.

Regulation of transportation and sale of oil and NGLs. The liquids industry is also extensively regulated by numerous federal, state and local authorities. In a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act (the "ICA"). The Company does not believe these regulations affect it any differently than other producers.

The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable." Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

Rates of interstate liquids pipelines are currently regulated by FERC primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by FERC. For the five-year period beginning in 2010, FERC established an annual index adjustment equal to the

change in the producer price index for finished goods plus 2.65 percent. This adjustment is subject to review every five years. Under FERC's regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows for the Company.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to the

Company. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that the Company relies upon for liquids transportation could have a material adverse effect on its business, financial condition, results of operations and cash flows. However, the Company believes that access to liquids pipeline transportation services generally will be available to it to the same extent as to its similarly-situated competitors. Intrastate liquids pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate liquids pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate liquids pipeline rates, varies from state to state. The Company believes that the regulation of liquids pipeline transportation rates will not affect its operations in any way that is materially different from the effects on its similarly-situated competitors.

In November 2009, the Federal Trade Commission ("FTC") issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1.0 million per violation per day. In July 2010, the U.S. Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission ("CFTC") to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FERC with respect to anti-manipulation in the gas industry and the FTC with respect to oil purchases and sales, as described above. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1.0 million or triple the monetary gain to the person for each violation.

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

Transportation of hazardous materials. The federal Department of Transportation has adopted regulations requiring that certain entities transporting designated hazardous materials develop plans to address security risks related to the transportation of hazardous materials. The Company does not believe that these requirements will have an adverse effect on the Company or its operations. The Company cannot provide any assurance that the security plans required under these regulations would protect against all security risks and prevent an attack or other incident related to the Company's transportation of hazardous materials.

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," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" 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 the Company's ability to implement business plans or complete development activities 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;
- inventory levels at Cushing, Oklahoma, the benchmark for WTI oil prices;
- oil, NGL and gas inventory levels in the United States;

- the capacity of U.S. refiners to absorb increasing domestic supplies of oil and condensate;
- weather conditions;
- overall domestic and global political and economic conditions, including laws, regulations and administrative policies that restrict the export of the Company's products;
- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- the effect of liquefied natural gas deliveries to and exports from the United States;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations and taxation;

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- 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, during 2013, oil prices fluctuated from a low of $86.68 per BBL in April to a high of $110.53 per BBL in September, while gas prices fluctuated from a low of $3.11 per MCF in January to a high of $4.46 per MCF in December. During 2012, oil prices fluctuated from a high of $109.77 per BBL in February to a low of $77.69 per BBL in June, while gas prices fluctuated from a low of $1.91 per MCF in April to a high of $3.90 per MCF in November.

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 noncancelable 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. These 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. 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. 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 scheduled and on budget. This impact may be magnified to the extent that the Company's ability to participate in the commodity price increases is limited by its derivative risk management activities.

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

To mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities, support the Company's annual capital budgeting and expenditure plans and reduce commodity price risk associated with certain capital projects, 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 MTM accounting treatment, and the changes in fair market value of the contracts are reported in the Company's statements of operations each quarter, which may result in significant noncash 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 liquidity when prices decline.

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, or become costlier, as a result of a variety of factors, including:

- unexpected drilling conditions;

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- unexpected pressure or irregularities in formations;
- equipment failures or accidents;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- restricted access to land for drilling or laying pipelines; and
- access to, and the cost and availability of, the equipment, services, resources and personnel required to complete the Company's drilling, completion and operating activities.

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 2014.

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

Declines in commodity prices may result in the Company having to make substantial downward adjustments to its 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 would be required to reduce the carrying value of the proved properties to their fair value. For example, during 2013, 2012 and 2011, the Company recognized impairment charges of $1.5 billion, $532.6 million and $354.4 million, respectively, due to the impairment of the Company's Raton field, Barnett Shale field, and Edwards and Austin Chalk gas fields in South Texas, respectively, due to declines in long-term 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, 2013, the Company carried unproved oil and gas property costs of $123.4 million. GAAP requires periodic evaluation of these costs on a project-by-project basis. These evaluations are affected by the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of the leases, and 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 periodically evaluates its goodwill for impairment and could be required to recognize noncash charges in the earnings of future periods.

At December 31, 2013, the Company carried goodwill of $274.3 million. Goodwill is assessed for impairment annually during the third quarter and whenever facts or circumstances indicate that the carrying value of the Company's goodwill may be impaired, which may require an estimate of the fair values of the reporting unit's assets and liabilities. Those assessments may be affected by (a) additional reserve adjustments both positive and negative, (b) results of drilling activities, (c) management's outlook for 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 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 from time to time contributed to 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:

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- 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 effect 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's ability to complete dispositions of assets, or interests in assets, may be subject to factors beyond its control, and in certain cases the Company may be required to retain liabilities for certain matters.

From time to time, the Company sells an interest in a strategic asset for the purpose of assisting or accelerating the asset's development. In addition, 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 such interests or nonstrategic assets or complete announced dispositions, including the receipt of approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the interests or purchase the nonstrategic assets on terms and 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 divestiture, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

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

As of December 31, 2013, the Company owned interests in six gas processing plants and nine treating facilities. The Company is the operator of two of the gas processing plants and all nine 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 improper operation 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 unforeseen interruptions to the Company's operations and substantial losses to the Company for which the Company may not be adequately insured.

The Company's operations, including well stimulation and completion activities, such as hydraulic fracturing, 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 and vessel ruptures, encountering NORM, and unauthorized discharges of toxic gases, brine, well stimulation and completion fluids or other pollutants into the surface and subsurface environment;
- high costs, shortages or delivery delays of equipment, labor or other services or water for hydraulic fracturing;
- 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.

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The Company's overall exposure to operational risks may increase as its drilling activity expands and as it seeks to directly provide drilling, fracture stimulation and other services internally. 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.

Part of the Company's strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

The Company's operations involve utilizing some of the latest drilling and completion techniques as developed by it and its service providers. Risks that the Company faces while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that the Company faces while completing wells include, but are not limited to, the following:

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

The results of drilling in emerging areas are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. New discoveries and emerging formations have limited or no production history and, consequently, the Company is more limited in assessing future drilling results in these areas. If the Company's drilling results are worse than anticipated, the return on investment for a particular project may not be as attractive as anticipated and the Company may recognize noncash impairment charges to reduce the carrying value of its unproved properties.

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 activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. For example, the Company's proved reserves as of December 31, 2013 include proved undeveloped reserves and proved developed reserves that are behind pipe of 102.5 MMBBLs of oil, 41.9 MMBBLs of NGLs and 328.9 BCF of gas. 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, access to and availability of equipment, services, resources and personnel and drilling results. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. 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 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 on commercially reasonable terms or otherwise to pipelines and storage facilities, gas gathering systems and other transportation, processing, fractionation and refining facilities to

market its oil, NGL and gas production; the Company relies on a limited number of purchasers for a majority of its products.
The marketing of oil, NGL 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, fractionation and refining facilities, as well as the existence of adequate markets. If there were insufficient capacity available on these systems, if these systems were unavailable to the Company, or if access to these systems were to become commercially unreasonable, 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 or awaits the availability of third party facilities. The Company also relies (and expects to rely in the future) on facilities developed and owned by third parties in order to store, process, transport, fractionate and sell its oil, NGL 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 transportation, storage or processing and fractionation facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist.

For example, following Hurricanes Gustav and Ike in 2008, certain Permian Basin gas processors were forced to shut down their plants due to the shutdown of the Texas Gulf Coast NGL fractionators. The Company was able to produce its oil wells and vent or flare the associated gas; however, there is no certainty the Company will be able to vent or flare gas in the future due to potential changes in regulations. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. The Company has periodically experienced high line pressure at its tank batteries, which has occasionally led to the flaring of gas due to the inability of the gas gathering systems in the areas to support the increased gas production. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, the Company may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

To the extent that the Company enters into transportation contracts with gas pipelines that are subject to FERC regulation, the Company is subject to FERC requirements related to use of such capacity. Any failure on the Company's part to comply with FERC's regulations and policies or with an interstate pipeline's tariff could result in the imposition of civil and criminal penalties.

A limited number of companies purchase a majority of the Company's oil, NGLs and gas. The loss of a significant purchaser could have a material adverse effect on the Company's ability to sell its production.

The Company is growing production in areas of high industry activity, which may affect its ability to obtain the personnel, equipment, services, resources and facilities access needed to complete its development activities as planned or result in increased costs.

The Company's operations and drilling activity are concentrated in areas in which industry activity has increased rapidly, particularly in the Spraberry field in West Texas and the Eagle Ford Shale play in South Texas. As a result, demand for personnel, equipment, power, services and resources, as well as access to transportation, processing and refining facilities in these areas, has increased, as have the costs for those items. In addition, hydraulic fracturing and other operations require significant quantities of water, which supply may be affected by drought conditions. Any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for the Company to complete its planned development activities, including the result of any changes in laws or regulations applicable to the Company's operations relating to water usage, could result in oil and gas production volumes being below the Company's forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on the Company's cash flow and profitability.

The refining industry may be unable to absorb rising U.S. oil and condensate production; in such a case, the resulting surplus could depress prices and restrict the availability of markets.

Under U.S. law and regulations, the export of oil and certain condensates is restricted. Absent a change in this law or an expansion of U.S. refining capacity, rising U.S. production of oil and condensate could result in a surplus of these products, which would likely cause prices for these commodities to fall and markets to constrict. In such circumstances, the returns on the Company’s capital projects would decline, possibly to levels that would make execution of the Company’s drilling plans uneconomical, and a lack of market for the Company's products could require that the Company shut in some portion of its production. If this were to occur, the Company’s production and cash flow could decrease, or could increase less than forecasted, which could have a material adverse effect on the Company's cash flow and profitability.

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

The oil and gas business involves the production, handling, sale and disposal of environmentally sensitive materials and is subject to environmental hazards, such as oil spills, produced water spills, gas leaks, pipeline and vessel ruptures and unauthorized discharges of substances or gases, that could expose the Company to substantial liability due to pollution and other environmental damage. Pollution and similar environmental risks generally are not fully insurable either because such insurance is not available or because of the high premium costs and deductible associated with obtaining such insurance. A variety of federal, state and local laws and regulations govern the environmental aspects of the oil and gas business. Noncompliance with these laws and regulations may subject the Company to administrative, civil or criminal penalties, remedial cleanups, and natural resource damages or other liabilities, and compliance with these laws and regulations may increase the cost of the Company's operations. Such laws and

regulations may also affect the costs of acquisitions. See "Item 1. Business — Competition, Markets and Regulations — Environmental and occupational health and safety matters" above for additional discussion related to environmental risks.

Environmental laws and regulations are subject to amendment or replacement by more stringent laws and regulations and no assurance can be given that continued compliance with existing or future environmental laws and regulations 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.

The Company could incur significant costs and liabilities in responding to contamination that occurs at its properties or as a result of its operations.

There is inherent risk of incurring significant environmental costs and liabilities in operations upon the Company's properties due to its handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and as a result of historical operations and waste disposal practices by prior owners and operators. The Company currently owns, leases or operates properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes have been released on or under such properties and could be released during future operations. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons and wastes on, under or from the Company's properties. Private parties, including lessors of properties on which the Company operates and the owners or operators of properties adjacent to the Company's operations and facilities where the Company's petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or property damage. The Company may not be able to recover some or any of these costs from insurance or other sources of contractual indemnity.

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 and a credit facility. The terms of the Company's borrowings 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 G 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, 2013 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.

The Company faces significant competition, and some 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 evaluate, operate and develop properties.

Some 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 and local laws and regulations. For instance, in connection with the Company's CBM operations in the Raton Basin in Colorado, the Colorado Supreme Court

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. As another example, the underground injection well program under the SDWA requires permits from the EPA or an 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. In some areas of Texas, there has been concern that certain formations into which disposal wells are injecting produced waters could become over-pressured after many years of injection, and the governing Texas regulatory agency is reviewing the data to determine whether any action is necessary to address this issue. If the Texas state

agency were to decline to issue permits for new injection wells into the formations currently utilized by the Company, the Company may be required to seek alternative methods of disposing of produced waters, including injecting into deeper formations, which could increase its costs. 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 sales of oil, gas, NGLs or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks.

FERC, the FTC and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets relevant to the Company's business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to the Company's physical sales of oil, gas, NGLs or other energy commodities, and any derivative activities related to these energy commodities, the Company is required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect the Company's business results of operations and financial condition.

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 estimates 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 proved reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating proved reserves:

- the quantities of oil and gas that are ultimately recovered;
- the production costs incurred to recover the reserves;
- 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.

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. Risk Factors" 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's business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, the Company faces various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of the Company's facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected the Company's operations to increased risks that could have a material adverse effect on the Company's business. In particular, the Company's implementation of various procedures and controls to monitor and mitigate security threats and to increase security for the Company's information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to the Company's operations and could have a material adverse effect on the Company's reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage the Company's reputation and lead to financial losses from remedial actions, loss of business or potential liability.

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.

The Company relies on a limited number of purchasers to purchase a majority of its products. To the extent that purchasers of the Company's production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to the Company if such purchasers were unable to access the credit or equity markets for an extended period of time. 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.

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

The worldwide economic outlook has been improving steadily since 2010, but if there are renewed concerns about global economic growth or government debt in Europe or the United States, there could be a significant adverse effect on global financial markets and commodity prices. If the economic climate in the United States or abroad were to

deteriorate, demand for petroleum products could diminish, which could depress the prices at which the Company could 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.

In recent years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas companies. Such tax legislation 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. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could have an adverse effect on the Company's financial position, results of operations and cash flows.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, NGLs and gas the Company produces.

In 2009, the EPA officially published its findings that emissions of GHGs present an endangerment to public 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. Based on these findings, the EPA adopted regulations under the CAA establishing Title V and PSD permitting requirements for large sources of GHGs. The Company could become subject to these permitting requirements and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that the Company may seek to construct in the future if they would otherwise emit large volumes of GHGs. The EPA has also adopted rules requiring the reporting of GHG emissions on an annual basis from specified GHG emission sources in the United States, including certain oil and gas production facilities, which include certain of the Company's facilities. While the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation in the United States, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If the U.S. Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on the Company's operations. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would affect the Company's business, any such future laws and regulations could require the Company to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, including the imposition of a carbon tax. Any such legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and gas, which could reduce the demand for the oil and gas the Company produces. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Company's business, financial condition and results of operations. See "Item 1. Business - Competition, Markets and Regulations - Environmental and occupational health and safety matters - Climate change" for additional discussion relating to climate change.

The enactment of derivatives legislation could have an adverse effect on the Company's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations for its implementation. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Colombia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide derivative transactions. As these new position limit rules are not yet final, the impact of those provisions on the Company is uncertain at this time. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require the Company, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although the Company believes it qualifies for the end-user exception from the mandatory clearing requirements for swaps entered to mitigate its commercial risks, the application of the mandatory clearing and trade

execution requirements to other market participants, such as swap dealers, may change the cost and availability of the Company's derivatives. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished or what the effect of any such regulations will be on the Company. For example, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to the Company for capital expenditures, therefore reducing its ability to execute derivatives to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to the Company is uncertain at this time. The Dodd-Frank Act also may require the counterparties to the Company's derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The full impact of the Dodd-Frank Act and related regulatory requirements upon the Company's business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially

alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters, reduce the Company's ability to monetize or restructure its existing derivative contracts, and increase the Company's exposure to less creditworthy counterparties. If the Company reduces its use of derivatives as a result of the Dodd-Frank Act and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and gas. The Company's revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Company, its financial condition and its results of operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions or delays and adversely affect the Company's production.

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The Company routinely utilizes hydraulic fracturing techniques in the majority of its drilling and completion programs. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions, but the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the SDWA's Underground Injection Control Program and published final permitting guidance in February 2014 addressing the performance of such activities. In 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and in its Semi-annual Regulatory agenda published in July 2013, the agency continues to project the future issuance of an Advance Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. The EPA has published final rules under the CAA that, among other things, require producers to reduce volatile organic compound emissions from certain subcategories of fractured and refractured gas wells for which well completion operations are being conducted by routing flowback emissions to a gathering line or capturing and combusting flowback emissions using a combustion device, such as a flare, until January 1, 2015 and performing green completions, with or without combustion devices, on or after January 1, 2015. Also, in May 2013, the BLM published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface.

In addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. Certain states in which the Company operates, including Colorado and Texas have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and well-construction requirements on hydraulic-fracturing operations. In addition, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. In the event federal, state or local restrictions are adopted in areas where the Company is currently conducting, or in the future plan to conduct operations, the Company may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps be limited or precluded in the drilling of wells or in the amounts that the Company is ultimately able to produce from its reserves.

Certain governmental reviews were recently conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and a draft report is expected to be available for public comment and peer review in 2014. Moreover, the EPA is developing effluent limitations for the

treatment and discharge of wastewater resulting from hydraulic fracturing activities and is expected to propose these standards in 2014. These studies, or future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. See "Item 1. Business - Competition, Markets and Regulations - Environmental and occupational health and safety matters" for additional discussion related to environmental risks associated with the Company's hydraulic fracturing activities.

Laws and regulations pertaining to threatened and endangered species could delay or restrict the Company's operations and cause it to incur substantial costs.

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitats, migratory birds, wetlands and natural resources. These statutes include the ESA, the Migratory Bird Treaty Act, the CWA and CERCLA. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are

necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or oil and gas development. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in limitations on its development and production activities that could have an adverse effect on the Company's ability to develop and produce reserves.

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. 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.

The Company's sand mining operations are subject to operating risks that are often beyond the Company's control, and such risks may not be covered by insurance.

Ownership of industrial sand mining operations are subject to risks, many of which are beyond the Company's control. These risks include:

- unusual or unexpected geological formations or pressures;
- cave-ins, pit wall failures or rock falls;
- unanticipated ground, grade or water conditions;
- inclement or hazardous weather conditions, including flooding, and the physical impacts of climate change;
- environmental hazards, such as unauthorized spills, releases and discharges of wastes, vessel ruptures and emission of unpermitted levels of pollutants;
- changes in laws and regulations;
- inability to acquire or maintain necessary permits or mining or water rights;
- restrictions on blasting operations;
- inability to obtain necessary production equipment or replacement parts;
- reduction in the amount of water available for processing;
- technical difficulties or failures;
- labor disputes;
- late delivery of supplies;
- fires, explosions or other accidents; and
- facility interruptions or shutdowns in response to environmental regulatory actions.

Any of these risks could result in damage to, or destruction of, the Company's mining properties or production facilities, personal injury, environmental damage, delays in mining or processing, losses or possible legal liability. Not all of these risks are insurable, and the Company's insurance coverage contains limits, deductibles, exclusions and endorsements. The Company's insurance coverage may not be sufficient to meet its needs in the event of loss and any such loss may have a material adverse effect on the Company.

The Company's estimates of sand reserves and resource deposits are imprecise and actual reserves could be less than estimated.

The Company bases its sand reserve and resource estimates on engineering, economic and geological data assembled and analyzed by engineers and geologists, which are periodically reviewed by outside firms. However, commercial sand reserve estimates are necessarily imprecise and depend to some extent on statistical inferences drawn from available drilling data, which may prove unreliable. There are numerous uncertainties inherent in estimating quantities and qualities of commercial sand reserves and costs to mine recoverable reserves, including many factors beyond the Company's control. Estimates of economically recoverable commercial sand reserves necessarily depend on a number of factors and assumptions, all of which may vary considerably from actual results, such as:

- geological and mining conditions or effects from prior mining that may not be fully identified by available data or that may differ from experience;
- assumptions concerning future prices of commercial sand products, operating costs, mining technology improvements, development costs and reclamation costs; and
- assumptions concerning future effects of regulation, including the issuance of required permits and taxes by governmental agencies.

The Company's sand mining operations are subject to extensive environmental and occupational health and safety regulations that impose significant costs and potential liabilities.

The Company's sand mining operations are subject to a variety of federal, state and local environmental requirements affecting the mining and mineral processing industry, including, among others, those relating to employee health and safety, environmental permitting and licensing, air emissions and water discharges, GHG emissions, water pollution, waste management and disposal, remediation of soil and groundwater contamination, land use restrictions, reclamation and restoration of properties, hazardous materials and natural resources. Some environmental laws impose substantial penalties for noncompliance, and others, such as the CERCLA, impose strict, retroactive and joint and several liability for the remediation of releases of hazardous substances. Failure to properly handle, transport, store or dispose of hazardous materials or otherwise conduct the Company's sand mining operations in compliance with environmental laws could expose the Company to liability for governmental penalties, cleanup costs and civil or criminal liability associated with releases of such materials into the environment, damages to property or natural resources and other damages, as well as potentially impair the Company's ability to conduct its sand mining operations. In addition, environmental laws and regulations are subject to amendment, replacement or interpretation by more stringent and comprehensive legal requirements. The Company's continued compliance with existing or future laws and regulations could restrict the Company's ability to expand its facilities or extract mineral deposits or could require the Company to acquire costly equipment or to incur other significant expenses in connection with its sand mining operations, which restrictions or costs could have a material adverse effect on the Company's sand mining operations.

Any failure by the Company to comply with applicable environmental laws and regulations in connection with its sand mining operations may cause governmental authorities to take actions that could adversely affect the Company, including:

- issuance of administrative, civil and criminal penalties;
- denial, modification or revocation of permits or other authorizations;
- imposition of injunctive obligations or other limitations on the Company's operations, including interruptions or cessation of operations; and
- requirements to perform site investigatory, remedial or other corrective actions.

In addition to environmental regulation, the Company's sand mining operations are subject to laws and regulations relating to worker health and safety, including such matters as human exposure to crystalline silica dust. Several federal and state regulatory authorities, including the U.S. Mining Safety and Health Administration, may continue to propose changes in their regulations regarding workplace exposure to crystalline silica, such as permissible exposure limits and required controls and personal protective equipment.

The Company's sand mining operations are subject to the Federal Mine Safety and Health Act of 1977, which imposes stringent health and safety standards on numerous aspects of the Company's sand mining operations.

The Company's sand mining operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures, operating equipment and other matters. The Company's failure to comply with such standards, or changes in such standards or the interpretation or enforcement thereof, could have a material adverse effect on the Company's sand mining operations or otherwise impose significant restrictions on the Company's ability to conduct mineral extraction and processing operations.

The Company's sand mining operations are subject to extensive other regulations that impose significant costs and liabilities.

In addition to the environmental and occupational health and safety regulation discussed above, the Company's sand mining operations are also subject to extensive governmental regulation on matters such as permitting and licensing requirements, reclamation and restoration of mining properties after mining is completed, and the effects that mining have on groundwater quality and availability. Also, the Company's sand mining operations require numerous governmental, environmental, mining and other permits, water rights and approvals authorizing operations at each sand mining facility.

In order to obtain permits and renewals of permits in the future for its sand mining operations, the Company may be required to prepare and present data to governmental authorities pertaining to the effect that any such activities may have on the environment.

Obtaining or renewing required permits may be delayed or prevented due to opposition by neighboring property owners, members of the public or other third parties and other factors beyond the Company's control. A decision by a governmental agency or other third party to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on the Company's sand mining operations at the affected facility. Current or future regulations could have a material adverse effect on the Company's sand mining operations and the Company may not be able to renew or obtain permits in the future.

The Company's sand mining operations entail silica-related health issues and litigation that could have a material adverse effect on the Company.

The inhalation of respirable crystalline silica dust is associated with the lung disease silicosis. There is evidence of an association between crystalline silica exposure or silicosis and lung cancer and a possible association with other diseases, including immune system disorders, such as scleroderma. These health risks have been, and may continue to be, a significant issue confronting the commercial sand industry. The actual or perceived health risks of mining, processing and handling sand could materially and adversely affect the Company through the threat of product liability or employee lawsuits and increased scrutiny by federal, state and local regulatory authorities.

Premier Silica is named as a defendant, usually among many defendants, in numerous products liability lawsuits brought by or on behalf of current or former employees of Premier Silica's customers alleging damages caused by silica exposure. As of December 31, 2013, Premier Silica was the subject of approximately 2,200 silica exposure claims, the great majority of which have been inactive for many years due to the plaintiffs' failure to meet specific legal requirements to advance their claims. Almost all of the claims pending against Premier Silica arise out of the alleged use of Premier Silica's sand products in foundries or as an abrasive blast media and have been filed in the states of Texas, Florida and Missouri, although some cases have been brought in many other jurisdictions over the years.

It is possible that Premier Silica will continue to have silica-related products liability claims filed against it, including claims that allege silica exposure for periods for which there is not insurance coverage. Any pending or future claims or inadequacies of insurance coverage or indemnification from the seller could have a material adverse effect on the Company's results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Reserve Estimation Procedures and Audits

The information included in this Report about the Company's proved reserves as of December 31, 2013, 2012 and 2011 is based on evaluations prepared by the Company's engineers and (i) audited by Netherland, Sewell & Associates, Inc. ("NSAI"), with respect to the Company's major properties included in its continuing operations for all periods, and (ii) with respect to the Company's Oooguruk field properties in Alaska, audited by Ryder Scott Company, L.P. ("RSC"), as of December 31, 2012. 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 Corporate Reserves Group ("Corporate Reserves"), and annual external audits of substantial portions of the Company's proved reserves by NSAI.

Individual asset teams are responsible for the day-to-day management of the oil and gas activities in each of the Company's Permian Basin, Rockies, Mid-Continent, South Texas, Barnett Shale and Alaska asset areas (the "Asset Teams"). The Company's Asset Teams are each staffed with reservoir engineers and geoscientists who prepare reserve estimates at the end of each calendar quarter for the assets that they manage, using reservoir engineering information technology. There is shared oversight of the Asset Teams' reservoir engineers by the Asset Teams' managers and the Vice President of Corporate Reserves, each of whom is in turn subject to direct or indirect oversight by the Company's

management committee ("MC"). The Company's MC is comprised of its Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and other Executive Vice Presidents. The Asset Teams' reserve estimates are reviewed by the Asset Team reservoir engineers before being submitted to Corporate Reserves for further review. The reserve estimates are summarized in reserve reconciliations that quantify reserve changes since the previous year end as revisions of previous estimates, purchases of minerals-in-place, improved recovery, 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 Corporate Reserves, in consultation with the Company's accounting and financial management personnel. Annually, the MC reviews the reserve estimates and any differences with the reserve auditors (for the portion of the reserves audited by NSAI or RSC) on a consolidated basis before these estimates are approved. The engineers and geoscientists who participate in the reserve estimation and disclosure process periodically attend training provided by external consultants and/or through internal Pioneer programs. Additionally, Corporate Reserves has prepared and maintains written policies and guidelines 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 proved reserve audits performed by NSAI for 2013, 2012 and 2011, and by RSC for 2012, in the aggregate represented 94 percent, 95 percent and 90 percent of the Company's 2013, 2012 and 2011 proved reserves, respectively; and 92 percent, 99 percent and 91 percent of the Company's 2013, 2012 and 2011 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 (the "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 the 2007 SPE publication entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information."
- The estimation of 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.

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 interpretations, or making its own interpretations. 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 evaluations 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 values of such reserves discounted at ten percent. NSAI reviewed its audit differences with the Company, and, in a number of cases, held meetings with the Company to review additional reserves work performed by the Company's technical teams and any updated performance data related to the proved reserve differences. Such data was incorporated, as appropriate, by both parties into the proved 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 the reserve auditors and some were less than the estimates of the

reserve auditors. When such differences do not exceed ten percent in the aggregate and NSAI is satisfied that the proved reserves and pre-tax present values 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 the reserve auditors. 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 present values discounted at ten percent are, in the aggregate, reasonable and have been prepared in accordance with the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the SPE.

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. Corporate Reserves is staffed by petroleum engineers with extensive industry experience and is managed by the Vice President of Corporate Reserves, 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 SPE. The qualifications of the Vice President of Corporate Reserves include 36 years of experience as a petroleum engineer, with 29 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 Charterholder.

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-2699. 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 35 years of practical experience in petroleum engineering, including over 33 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 directors of the SPE.

RSC provides worldwide petroleum property analysis services for energy clients, financial organizations and government agencies. RSC was founded in 1937 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-1580. The technical person primarily responsible for auditing the Company's Alaska reserves estimates in 2012 was a practicing consulting petroleum engineer at RSC since 2000 with over 29 years of practical experience in petroleum engineering. He graduated with a Bachelor of Science degree in Petroleum Engineering and a Master of Business Administration degree and at the time of the reserves audit he met or exceeded 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 directors of the SPE.

Technologies used in reserves estimates. Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped proved reserves only if an ability and intent has been established to drill the reserves within five years, unless specific circumstances justify a longer time period.

In the context of reserves estimations, reasonable certainty means a high degree of confidence that the quantities will be recovered and reliable technology means a grouping of one or more technologies (including computational methods) that has been field-tested and has been demonstrated to provide reasonable certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In estimating proved reserves, the Company uses several different traditional methods such as performance-based methods, volumetric-based methods and analogy with similar properties. In addition, the Company utilizes additional technical analysis such as seismic interpretation, wireline formation tests, geophysical logs and core data to provide incremental support for more complex reservoirs. Information from this incremental support is combined with the traditional technologies outlined above to enhance the certainty of the Company's proved reserve estimates.

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Proved Reserves
As of December 31, 2013 and 2012, the Company's oil and gas proved reserves are located entirely in the United States. The Company's proved reserves as of December 31, 2011 were almost exclusively located in the United States, except for less than one percent that were associated with discontinued operations in South Africa. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional details of the Company's discontinued operations. The following table provides information regarding the Company's proved reserves as of December 31, 2013, 2012 and 2011:

	Summary of Oil and Gas Reserves as of Fiscal Year-End Based on Average Fiscal-Year Prices Reserve Volumes					
	Oil (MBBLs)	NGLs (MBBLs)	Gas (MMCF) (a)	Total (MBOE)	%	
December 31, 2013:						
Developed	256,638	148,161	1,703,667	688,743	81	%
Undeveloped	85,467	37,261	202,674	156,507	19	%
Total proved reserves	342,105	185,422	1,906,341	845,250	100	%
Less proved reserves associated with discontinued operations	24,128	10,210	80,113	47,690	6	%
Total proved reserves associated with continuing operations	317,977	175,212	1,826,228	797,560	94	%
December 31, 2012:						
Developed	230,700	134,637	1,605,209	632,872	58	%
Undeveloped	256,138	97,939	592,271	452,789	42	%
Total proved reserves	486,838	232,576	2,197,480	1,085,661	100	%
Less proved reserves associated with discontinued operations	48,274	24,137	158,307	98,796	9	%
Total proved reserves associated with continuing operations	438,564	208,439	2,039,173	986,865	91	%
December 31, 2011:						
Developed	190,206	120,405	1,853,363	619,506	58	%
Undeveloped	239,799	90,630	677,675	443,375	42	%
Total proved reserves	430,005	211,035	2,531,038	1,062,881	100	%
Less proved reserves associated with discontinued operations	32,301	13,011	117,299	64,862	6	%
Total proved reserves associated with continuing operations	397,704	198,024	2,413,739	998,019	94	%

(a) Total proved gas reserves contain 240,093 MMCF, 280,344 MMCF and 301,123 MMCF of gas that the Company expected to be produced and used as field fuel (primarily for compressors) before the gas is delivered to a sales point, as of December 31, 2013, 2012 and 2011, respectively.

The Company's Standardized Measure of total proved reserves as of December 31, 2013 was $7.3 billion, including $6.3 billion and $1.0 billion of proved developed and proved undeveloped, respectively. The Company's Standardized Measure of total proved reserves as of December 31, 2012 was $6.4 billion, including $5.0 billion and $1.4 billion of

proved developed and proved undeveloped, respectively. The Company's Standardized Measure of total proved reserves as of December 31, 2011 was $7.8 billion, including $5.5 billion and $2.3 billion of proved developed and proved undeveloped, respectively.

See the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" for additional details of the estimated quantities of the Company's proved reserves, including explanations for material changes in proved developed and proved undeveloped reserves.

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Description of Properties
The following tables summarize the Company's development and exploration/extension drilling activities during 2013:

	Development Drilling				
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	136	311	387	1	59
South Texas—Eagle Ford Shale	11	45	40	—	16
Mid-Continent	—	11	11	—	—
Total continuing operations	147	367	438	1	75
Barnett Shale	—	4	3	—	1
Alaska	4	3	3	—	4
Total including discontinued operations	151	374	444	1	80

	Exploration/Extension Drilling					
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Wells Sold	Ending Wells In Progress
Permian Basin	17	128	114	—	—	31
South Texas—Eagle Ford Shale	21	95	92	—	—	24
South Texas—Edwards and Austin Chalk	—	1	1	—	—	—
Other	—	5	—	2	—	3
Total continuing operations	38	229	207	2	—	58
Barnett Shale	9	52	37	6	1	17
Alaska	2	1	—	1	—	2
Total including discontinued operations	49	282	244	9	1	77

The following table summarizes the Company's average daily oil, NGL, gas and total production by asset area during 2013:

	Oil (BBLs)	NGLs (BBLs)	Gas (MCF) (a)	Total (BOE)
Permian Basin	52,596	15,196	70,766	79,586
South Texas—Eagle Ford Shale	13,737	10,421	80,458	37,568
Raton Basin	—	—	134,591	22,432
Mid-Continent	3,020	6,801	40,475	16,567
South Texas—Edwards and Austin Chalk	171	2	30,685	5,287
Other	3	2	69	16
Total continuing operations	69,527	32,422	357,044	161,456
Barnett Shale	1,492	3,193	23,443	8,592
Alaska	4,201	—	—	4,201
Total including discontinued operations	75,220	35,615	380,487	174,249

(a) Gas production excludes gas produced and used as field fuel.

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The following table summarizes the Company's costs incurred by asset area during 2013:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
	(in thousands)					
Permian Basin	$3,550	$50,082	$677,528	$1,043,600	$28,921	$1,803,681
Mid-Continent	18	218	2,633	17,561	983	21,413
Raton Basin	—	—	5,119	7,582	(15,847)	(3,146)
South Texas—Eagle Ford Shale	35	1,711	372,065	208,507	589	582,907
South Texas—Edwards and Austin Chalk	(32)	(17)	3,171	3,892	3,032	10,046
Other	10	3,527	23,351	1	74	26,963
Total continuing operations	$3,581	$55,521	$1,083,867	$1,281,143	$17,752	$2,441,864
Barnett Shale	9,280	7,641	135,441	49,664	(109)	201,917
Alaska	—	—	68,604	140,557 (a)	(5,129)	204,032
Total including discontinued operations	$12,861	$63,162	$1,287,912	$1,471,364	$12,514	$2,847,813

(a) Includes $7.1 million of capitalized interest associated with the Oooguruk development project.

Permian Basin

Spraberry field. The Spraberry field was discovered in 1949, encompasses eight counties in West Texas and the Company believes it is the 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 six formations, the upper and lower Spraberry, the Dean, the Wolfcamp, the Strawn and the Atoka, at depths ranging from 6,700 feet to 11,300 feet. The Company believes the Spraberry and Wolfcamp formations offer excellent horizontal drilling opportunities to grow oil and gas production because of the significant resource in place and numerous undeveloped drilling locations. The Company expects to improve the incremental recovery rates in the Spraberry field through horizontal, infill and deeper formation drilling while containing operating expenses and drilling costs through economies of scale and vertical integration of field services.

During 2013, the Company drilled 502 wells in the Spraberry field and its total acreage position now approximates 823,000 gross acres (717,000 net acres). The Company currently has 29 rigs operating in the Spraberry field, of which 11 are drilling vertical wells and 18 are drilling horizontal wells, and has plans to add an additional six horizontal drilling rigs by the end of the first quarter of 2014. During 2014, the Company expects to drill approximately 200 vertical wells and 255 horizontal wells, with the horizontal wells being principally drilled in the Wolfcamp Shale horizon. The Company expects to spend $2.4 billion of drilling capital in the Spraberry field during 2014.

The Company believes it has significant resource potential within its acreage based on its extensive geologic data covering the Spraberry and Wolfcamp A, B, C and D intervals and its drilling results to-date. During 2013, the Company completed 21 wells in the northern portion of the play and 100 horizontal wells in the southern portion of the play. In 2014, the Company expects to drill 140 horizontal wells in the northern portion of the play and 115 horizontal wells in the southern portion of the play.

During 2013, the Company initiated horizontal Wolfcamp Shale drilling activities in the northern portion of its Spraberry acreage position to delineate the area. Wells drilled in the northern portion of the play were expected to benefit from greater original oil in place and higher reservoir pressures associated with deeper drilling depths. During 2013, the Company placed on production nine Wolfcamp B interval wells, four Wolfcamp D interval wells, five Lower Spraberry Shale interval wells, two Jo Mill Shale interval wells and one Wolfcamp A interval well with

encouraging results. The Company's drilling is currently focused in Midland, Martin, Glasscock and Andrews counties. The wells in these areas are expected to be drilled on three-well pads to gain efficiencies; therefore, the wells will not be completed until after the last well on each pad is drilled and, accordingly, production from these wells is not expected until all wells on the pad are ready to produce. With the addition of drilling rigs during the first quarter of 2014, combined with the effects of pad drilling, the Company expects production growth to be weighted towards the second half of 2014.

The Company continues to drill vertically to deeper intervals in the Spraberry field below the Wolfcamp interval, including the Strawn and Atoka intervals. The 2013 drilling program reflected 90 percent of the vertical wells being deepened below the Wolfcamp interval. The Company expects to drill approximately 200 vertical wells targeting deeper intervals during 2014. These wells are also being drilled to meet continuous drilling obligations.

In January 2013, the Company signed an agreement with Sinochem, an unaffiliated third party, to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field for consideration of $1.8 billion. In May 2013, the Company completed the sale to Sinochem for net cash proceeds of $623.8 million, resulting in a 2013 gain of $181.3 million related to the unproved property interests conveyed to Sinochem. Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play. Associated with the closing of the joint venture transaction, the Company conveyed a 40 percent interest in the producing horizontal Wolfcamp Shale wells in the joint venture area.

The Company plans to drill 115 horizontal wells during 2014 in the joint interest area. The Company drilled 100 horizontal Wolfcamp Shale wells during 2013 and had capital expenditures of $454.1 million in 2013. The 2014 drilling program will be focused on drilling in the higher return areas in northern Upton and Reagan counties, with approximately two-thirds of the wells being completed in the Wolfcamp B interval and the remainder being a mix of Wolfcamp A, C and D interval wells.

Sinochem also elected to participate in certain vertical wells that were drilled in the joint interest area after the December 1, 2012 effective date and received its share of production and costs from the Wolfcamp and deeper horizons based on the reserve contribution from the Wolfcamp and deeper intervals relative to reserves from all completed intervals. Pioneer's and Sinochem's participation in vertical wells is based on each party's interest without any drilling carry applied. Pioneer retained 100 percent of its vertical production in the joint interest area for wells drilled before the December 1, 2012 effective date. Pioneer also retained its current working interests in all horizons shallower than the Wolfcamp horizon and continues as operator of the properties in the joint interest area.

The Company continues to benefit from its integrated services to control drilling and operating costs and support the execution of its drilling and production activities in the Spraberry field. The Company owns 15 vertical drilling rigs and is currently utilizing seven Company-owned fracture stimulation fleets totaling approximately 170,000 horsepower in the Spraberry field (see Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's plan to sell its vertical drilling rig business). To support its growing operations, the Company also owns other field service equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. In addition, Premier Silica (the Company's wholly-owned sand mining subsidiary) is supplying brown sand for proppant, which is being used to fracture stimulate vertical and horizontal wells in the Spraberry and Wolfcamp Shale intervals.

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 Hugoton properties are located on 268,000 gross acres (235,000 net acres), covering approximately 400 square miles. The Company has working interests in approximately 1,200 wells in the Hugoton field, approximately 1,000 of which it operates.

The Company operates substantially all of the gathering and processing facilities, including the Satanta plant, which processes the production from the Hugoton field. In January 2011, the Company sold a 49 percent interest in the Satanta plant to an unaffiliated third party for the third party's commitment to dedicate gas volumes to the Satanta plant. This agreement has increased the Satanta plant's processing volumes and is expected to increase its economic longevity. The Company is also exploring opportunities to process other gas production in the Hugoton area at the Satanta plant. By maintaining operatorship of the gathering and processing facilities, the Company is able to control the production, gathering, processing and sale of its Hugoton field gas and NGL production.

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 has an average energy content of 1,365 BTU and is produced from approximately 700 wells on more than 246,000 gross acres (239,000 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 characterized by very low reservoir pressure, Pioneer continually works to improve compressor and gathering system efficiency.

Raton Basin

The Raton Basin properties are located in the southeast portion of Colorado. The Company owns 198,000 gross acres (178,000 net acres) in the center of the Raton Basin and produces CBM gas from the coal seams in the Vermejo and Raton formations from approximately 2,300 wells. 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 ensure availability. See Note D of Notes to Consolidated Financial

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Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the impairment charge recorded during 2013 to reduce the carrying value of the Company's gas properties in the Raton field.

South Texas Eagle Ford Shale

The Company's drilling activities in the South Texas area during 2013 continued to be primarily focused on delineation and development of Pioneer's substantial acreage position in the Eagle Ford Shale play. The 2013 drilling program was focused on liquids-rich drilling, with no wells drilled in dry gas acreage.

The Company completed 132 horizontal Eagle Ford Shale wells during 2013, all of which were successful, with average lateral lengths of 5,300 feet and, on average, 15-stage fracture stimulations. Additionally, the Company completed its first successful Upper Eagle Ford Shale well and estimates that approximately 25 percent of the Company's acreage is prospective for this interval in the Eagle Ford Shale play. The Company plans to spend $545 million of drilling capital in 2014 to drill approximately 110 Eagle Ford Shale wells. The Company has been using two Pioneer-owned fracture stimulation fleets during 2013 in the Eagle Ford Shale area and plans to continue that usage in 2014.

The Company's drilling operations in the Eagle Ford Shale continue to focus on improving drilling efficiencies. The Company has added approximately 300 drilling locations in the liquids-rich area of the play as a result of downspacing from 1,000 feet between wells (120-acre spacing) to 500 feet (60-acre spacing) between wells. Further downspacing and staggered testing to 175 feet between wells is underway in the liquids-rich areas where the 500-foot spacing was successful. Some areas will include testing of the Lower Eagle Ford Shale interval only, while others will include a combination of the Lower and Upper intervals. Early results from the initial 300-foot downspacing and staggered test in the Lower Eagle Ford Shale continue to be encouraging with five downspaced wells performing consistently with offset 500-foot spaced wells. The number of wells drilled from pads, as opposed to single-well locations, increased from about 45 percent of the Eagle Ford Shale wells during 2012 to about 80 percent in 2013, reflecting that most of the Company's acreage is now held by production. Pad drilling saves the Company a significant amount of capital costs per well, as compared to single-well location drilling. Pad sizes generally range from two wells to six wells. In 2014, most Eagle Ford Shale wells will be drilled utilizing three-well and four-well pads. None of the wells are completed until all of the wells on a pad are drilled. Therefore, the time between when the first well on a pad is spud and when the pad is placed on production is dependent on how many wells are drilled from the pad.

Over the past two years, the Company has been testing the use of lower-cost white sand instead of ceramic proppant to fracture stimulate wells drilled in shallower areas of the field. The Company is expanding the use of white sand proppant to deeper areas of the field to further define its performance limits. Early well performance has been similar to direct offset ceramic-stimulated wells. The Company fracture stimulated 100 wells with white sand proppant during 2013, with significant capital savings per well. The Company is continuing to monitor the performance of these wells and expects that the majority of its 2014 drilling program in the Eagle Ford Shale area will use lower-cost white sand proppant.

During June 2010, the Company entered into an Eagle Ford Shale joint venture transaction. Pursuant to the transaction, the Company entered into a purchase and sale agreement to sell 45 percent of its Eagle Ford Shale proved and unproved oil and gas properties to an unaffiliated third party for $212.0 million of cash proceeds. Under the terms of the transaction, the purchaser also paid a 75 percent carry obligation of $886.8 million to cover a portion of the Company's share of exploration, drilling and completion costs attributable to the Eagle Ford Shale assets during the period from June 2010 through December 2012. As of December 31, 2012, the purchaser's carry obligation was satisfied.

The Company owns a 50.1 percent member interest in EFS Midstream LLC ("EFS Midstream"), an entity formed by the Company to own and operate gas and liquids gathering, treating and transportation assets in the Eagle Ford Shale play. The Company does not have control of EFS Midstream and accounts for its investment in EFS Midstream under the equity method of accounting for investments in unconsolidated affiliates. EFS Midstream is obligated to construct midstream assets in the Eagle Ford Shale area. The majority of the construction of the midstream assets has been completed. Eleven of the 13 planned central gathering plants were completed as of December 31, 2013. EFS

Midstream is providing gathering, treating and transportation services for the Company during a 20-year contractual term. During 2011, EFS Midstream entered into a $300 million, five-year revolving credit facility that is available to fund infrastructure investments, distributions or working capital needs to the extent such uses exceed EFS Midstream's operating cash flows.

Barnett Shale

During the fourth quarter of 2013, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. The plan is expected to result in the sale of the Barnett Shale net assets during 2014. The Company classified the Barnett Shale field assets and liabilities as held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2013. Associated with the plan to sell the Barnett Shale field, the Company recorded a noncash impairment charge of $189.5 million during December 2013 to reduce the carrying value of the Barnett Shale net assets to their estimated fair value less costs

to sell. Historical results of operations from the Company's Barnett Shale field, and the related impairment loss, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's plan to sell its Barnett Shale assets.

Alaska

During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer Alaska, representing all the Company's net assets in Alaska including the Company's 70 percent working interest in the Oooguruk project. The sale of Pioneer Alaska continues to be subject to ongoing negotiations and certain other conditions, such as governmental approvals and buyer's arrangement of financing. The assets and liabilities of Pioneer Alaska are classified as held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2013. Associated with the planned sale of Pioneer Alaska, the Company recorded a noncash impairment charge of $539.8 million during December 2013 to reduce the carrying value of the Pioneer Alaska assets to their estimated fair value less costs to sell of $350.6 million. Pioneer Alaska's historical results of operations, and the related impairment loss, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

See Notes C and F of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's planned divestiture and exploration projects in Alaska, respectively.

The Company's plans to sell the Barnett Shale net assets and Pioneer Alaska are in differing stages of marketing and negotiation. No assurance can be given that the sales will be completed in accordance with the Company's plans.

International

During August 2012 and February 2011, the Company completed the sales of Pioneer South Africa and Pioneer Tunisia, respectively, to different unaffiliated third parties. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the sale of Pioneer South Africa and Pioneer Tunisia. As a result of these sales, the Company no longer has operations outside the United States.

Selected Oil and Gas Information

The following tables set forth selected oil and gas information for the Company as of and for each of the years ended December 31, 2013, 2012 and 2011. 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 price that the Company receives for the oil and gas it produces is largely a function of market supply and demand. Demand is affected by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or gas can result in substantial price volatility. Historically, commodity prices have been volatile and the Company expects that volatility to continue in the future. A substantial or extended decline in oil or gas prices or poor drilling results could have a material adverse effect on the Company's financial position, results of operations, cash flows, quantities of oil and gas reserves that may be economically produced and the Company's ability to access capital markets.

The following tables set forth production, price and cost data with respect to the Company's properties for 2013, 2012 and 2011. These amounts represent the Company's historical results from operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. The production amounts will not match the proved reserve volume tables in the "Unaudited Supplementary Information" section included in "Item 8. Financial Statements and Supplementary Data" because field fuel volumes are included in the proved reserve volume tables.

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PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2013					
	Included in Continuing Operations				Included in Discontinued Operations	Total
	Spraberry Field	Eagle Ford Shale Field	Raton Field	Total Company Fields	United States	
Production information:						
Annual sales volumes:						
Oil (MBBLs)	19,176	5,014	—	25,377	2,078	27,455
NGLs (MBBLs)	5,410	3,804	—	11,834	1,165	12,999
Gas (MMCF)	24,679	29,367	49,126	130,321	8,557	138,878
Total (MBOE)	28,699	13,712	8,188	58,931	4,669	63,601
Average daily sales volumes:						
Oil (BBLs)	52,537	13,737	—	69,527	5,693	75,220
NGLs (BBLs)	14,822	10,421	—	32,422	3,193	35,615
Gas (MCF)	67,614	80,458	134,591	357,044	23,443	380,487
Total (BOE)	78,627	37,568	22,432	161,456	12,793	174,249
Average prices:						
Oil (per BBL)	$93.30	$91.74	$—	$92.62	$98.81	$93.09
NGL (per BBL)	$30.34	$26.72	$—	$30.24	$25.31	$29.79
Gas (per MCF)	$3.23	$3.63	$3.27	$3.43	$3.00	$3.41
Revenue (per BOE)	$70.84	$48.73	$19.61	$53.55	$55.79	$53.71
Average costs (per BOE):						
Production costs:						
Lease operating	$11.38	$3.23	$6.25	$8.00	$15.93	$8.58
Third-party transportation charges	0.24	3.86	3.02	1.56	1.67	1.57
Net natural gas plant/gathering	(1.11)	0.01	1.90	0.10	(0.95)	0.02
Workover	1.45	0.20	—	0.77	2.70	0.91
Total	$11.96	$7.30	$11.17	$10.43	$19.35	$11.08
Production and ad valorem taxes:						
Ad valorem	$1.70	$0.65	$0.42	$1.22	$1.68	$1.25
Production	3.45	1.31	0.35	2.20	0.50	2.07
Total	$5.15	$1.96	$0.77	$3.42	$2.18	$3.32
Depletion expense	$18.47	$8.80	$18.97	$14.70	$21.49	$15.20

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PRODUCTION, PRICE AND COST DATA - (Continued)

	Year Ended December 31, 2012						
	Included in Continuing Operations				Included in Discontinued Operations		
	Spraberry Field	Eagle Ford Shale Field	Raton Field	Total Company Fields	United States	South Africa	Total
Production information:							
Annual sales volumes:							
Oil (MBBLs)	16,096	3,613	—	20,922	2,006	157	23,085
NGLs (MBBLs)	4,451	2,683	—	9,904	1,009	—	10,913
Gas (MMCF)	21,345	23,182	54,822	131,132	7,351	3,784	142,267
Total (MBOE)	24,104	10,160	9,137	52,682	4,239	787	57,708
Average daily sales volumes:							
Oil (BBLs)	43,978	9,871	—	57,165	5,480	428	63,073
NGLs (BBLs)	12,160	7,332	—	27,060	2,756	—	29,816
Gas (MCF)	58,319	63,338	149,787	358,284	20,085	10,340	388,709
Total (BOE)	65,858	27,759	24,965	143,939	11,583	2,151	157,673
Average prices, including hedge results and amortization of deferred VPP revenue (a):							
Oil (per BBL)	$90.57	$93.84	$—	$90.67	$93.20	$108.62	$91.01
NGL (per BBL)	$32.23	$31.81	$—	$34.04	$30.86	$—	$33.75
Gas (per MCF)	$2.58	$2.81	$2.41	$2.60	$2.49	$8.50	$2.75
Revenue (per BOE)	$68.72	$48.18	$14.48	$48.88	$55.75	$62.48	$49.57
Average prices, excluding hedge results and amortization of deferred VPP revenue (a):							
Oil (per BBL)	$87.95	$93.84	$—	$88.81	$93.20	$108.62	$89.32
NGL (per BBL)	$32.23	$31.81	$—	$34.04	$30.86	$—	$33.75
Gas (per MCF)	$2.58	$2.81	$2.41	$2.60	$2.49	$8.50	$2.75
Revenue (per BOE)	$66.97	$48.18	$14.48	$48.15	$55.75	$62.48	$48.90
Average costs (per BOE):							
Production costs:							
Lease operating	$11.33	$3.21	$6.47	$7.91	$16.28	$2.86	$8.46
Third-party transportation charges	0.17	3.00	3.12	1.31	1.33	—	1.29
Net natural gas plant/gathering	(0.49)	—	1.82	0.54	(0.40)	—	0.47
Workover	1.71	0.08	—	0.83	1.10	—	0.84
Total	$12.72	$6.29	$11.41	$10.59	$18.31	$2.86	$11.06
Production and ad valorem taxes:							
Ad valorem	$1.78	$0.71	$0.17	$1.22	$1.69	$—	$1.24
Production	3.47	2.00	0.11	2.17	0.44	—	2.01
Total	$5.25	$2.71	$0.28	$3.39	$2.13	$—	$3.25
Depletion expense	$15.58	$5.51	$19.52	$12.82	$23.37	$—	$13.42

(a) The Company records the amortization of deferred VPP revenue at a field level but does not record the results of its hedging activities at a field level. As of December 31, 2012, the Company had no further obligation to deliver oil under the VPP and did not have any hedging activities.

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PRODUCTION, PRICE AND COST DATA - (Continued)

	Year Ended December 31, 2011							
	Included in Continuing Operations				Included in Discontinued Operations			
	Spraberry Field	Eagle Ford Shale Field	Raton Field	Total Company Fields	United States	South Africa	Tunisia	Total
Production information:								
Annual sales volumes:								
Oil (MBBLs)	10,011	1,600	—	12,989	1,836	193	201	15,219
NGLs (MBBLs)	3,844	1,088	—	7,708	500	—	—	8,208
Gas (MMCF)	15,899	10,227	58,601	121,496	4,020	7,508	181	133,205
Total (MBOE)	16,505	4,393	9,767	40,947	3,006	1,445	229	45,627
Average daily sales volumes:								
Oil (BBLs)	27,428	4,383	—	35,587	5,031	530	547	41,695
NGLs (BBLs)	10,530	2,982	—	21,119	1,368	—	—	22,487
Gas (MCF)	43,559	28,020	160,550	332,866	11,013	20,570	496	364,945
Total (BOE)	45,218	12,035	26,758	112,184	8,234	3,958	630	125,006
Average prices, including hedge results and amortization of deferred VPP revenue (a):								
Oil (per BBL)	$95.93	$89.02	$—	$ 96.60	$96.58	$108.14	$99.03	$96.78
NGL (per BBL)	$42.38	$48.21	$—	$ 46.31	$45.64	$—	$—	$46.27
Gas (per MCF)	$3.44	$3.93	$3.81	$ 3.86	$3.41	$7.62	$13.04	$4.07
Revenue (per BOE)	$71.37	$53.51	$22.86	$ 50.80	$71.15	$54.09	$96.29	$52.48
Average prices, excluding hedge results and amortization of deferred VPP revenue (a):								
Oil (per BBL)	$91.44	$89.02	$—	$ 90.61	$96.58	$108.14	$99.03	$91.67
NGL (per BBL)	$42.38	$48.21	$—	$ 46.31	$45.64	$—	$—	$46.27
Gas (per MCF)	$3.44	$3.93	$3.81	$ 3.86	$3.41	$7.62	$13.04	$4.07
Revenue (per BOE)	$68.65	$53.51	$22.86	$ 48.90	$71.15	$54.09	$96.29	$50.77
Average costs (per BOE):								
Production costs:								
Lease operating	$10.40	$5.45	$6.49	$ 7.59	$14.75	$2.35	$7.61	$7.90
Third-party transportation charges	—	2.77	3.01	1.14	0.86	—	1.91	1.22
Net natural gas plant/gathering	(1.45)	—	2.15	0.16	—	—	—	0.14
Workover	1.74	0.02	—	0.80	1.08	—	(0.27)	0.78
Total	$10.69	$8.24	$11.65	$ 9.69	$16.69	$2.35	$9.25	$10.04
Production and ad valorem taxes:								
Ad valorem	$1.73	$0.27	$0.41	$ 1.17	$2.22	$—	$—	$1.20
Production	3.87	2.64	0.31	2.23	0.52	—	—	2.04
Total	$5.60	$2.91	$0.72	$ 3.40	$2.74	$—	$—	$3.24
Depletion expense	$11.41	$6.40	$14.46	$ 11.33	$29.15	$29.00	$—	$13.01

(a) The Company records the amortization of deferred VPP revenue at a field level but does not record the results of its hedging activities at a field level.

Productive wells. Productive wells consist of producing wells and wells capable of production, including shut-in wells and gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. One or more completions in the same well bore are counted as one well. Any well in which one of the multiple completions is an oil completion is classified as an oil well.

The following table sets forth the number of productive oil and gas wells attributable to the Company's properties as of December 31, 2013:

PRODUCTIVE WELLS

	Gross Productive Wells			Net Productive Wells		
	Oil	Gas	Total	Oil	Gas	Total
Continuing operations	6,928	4,989	11,917	6,146	4,430	10,576
Discontinued operations	28	125	153	20	119	139
Total	6,956	5,114	12,070	6,166	4,549	10,715

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2013:

LEASEHOLD ACREAGE

	Developed Acreage		Undeveloped Acreage		Royalty
	Gross Acres	Net Acres	Gross Acres	Net Acres	Acreage
Continuing operations	1,612,060	1,376,615	1,144,877	773,134	298,443
Discontinued operations	79,953	64,558	48,854	39,494	10,497
Total	1,692,013	1,441,173	1,193,731	812,628	308,940

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2013:

	Acres Expiring (a)	
	Gross	Net
2014	147,435	104,929
2015	107,383	72,453
2016	764,845	500,980
2017	112,794	77,613
2018	36,966	34,562
Thereafter	24,308	22,091
Total	1,193,731	812,628

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

Drilling and other exploratory and development activities. The following table sets forth the number of gross and net wells drilled by the Company during 2013, 2012 and 2011 that were productive or dry holes. 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 Year Ended December 31,			Net Wells Year Ended December 31,		
	2013	2012	2011	2013	2012	2011
Productive wells:						
Development	444	659	725	382	595	661
Exploratory	244	223	167	164	144	115
Dry holes:						
Development	1	10	11	1	6	10
Exploratory	9	6	1	6	6	1
Total	698	898	904	553	751	787
Success ratio (a)	99 %	98 %	99 %	99 %	98 %	99 %

(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.

Present activities. The following table sets forth information about the Company's wells that were in process of being drilled as of December 31, 2013:

	Gross Wells	Net Wells
Development	80	62
Exploratory	77	55
Total	157	117

ITEM 3. LEGAL PROCEEDINGS

The Company is party to various 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 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. See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding legal proceedings involving the Company.

ITEM 4. MINE SAFETY DISCLOSURES

The Company's sand mines are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K is included in Exhibit 95.1 to this Annual Report filed on Form 10-K.

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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 Company's board of directors (the "Board") declared dividends to the holders of the Company's common stock of $0.04 per share during each of the first and third quarters of the years ended December 31, 2013 and 2012. The Board intends to consider the payment of dividends to the holders of the Company's common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the Board and will depend on, among other things, the Company's earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that the Board deems relevant.

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, 2013 and 2012:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2013			
Fourth quarter	$227.42	$172.60	$—
Third quarter	$190.15	$146.19	$0.04
Second quarter	$157.81	$109.19	$—
First quarter	$133.68	$107.29	$0.04
Year ended December 31, 2012			
Fourth quarter	$110.67	$99.75	$—
Third quarter	$115.69	$82.18	$0.04
Second quarter	$117.05	$77.41	$—
First quarter	$119.19	$90.26	$0.04

On February 20, 2014, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $189.60 per share.

As of February 20, 2014, the Company's common stock was held by 13,527 holders of record.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table summarizes the Company's purchases of its common stock during the three months ended December 31, 2013:

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 2013	243	$201.35	—	—
November 2013	—	$—	—	—
December 2013	—	$—	—	—
Total	243	$201.35	—	$ —

(a) Consists of shares purchased from employees in order for the employees to satisfy tax withholding payments related to share-based awards that vested during the period.

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ITEM 6. SELECTED FINANCIAL DATA

The following selected consolidated financial data of the Company as of and for each of the five years ended December 31, 2013 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,				
	2013	2012	2011	2010	2009
	(in millions, except per share data)				
Statements of Operations Data:					
Oil and gas revenues	$3,155.7	$2,575.3	$2,080.2	$1,528.0	$1,283.5
Total revenues and other income	$3,719.5	$3,072.5	$2,513.2	$2,143.7	$1,076.4
Total costs and expenses (a)	$4,281.2	$2,235.0	$1,917.2	$1,329.4	$1,354.5
Income (loss) from continuing operations	$(349.9)	$547.0	$407.8	$545.2	$(178.6)
Income (loss) from discontinued operations, net of tax (b)	$(449.6)	$(304.2)	$474.1	$100.8	$136.3
Net income (loss) attributable to common stockholders	$(838.4)	$192.3	$834.5	$605.2	$(52.1)
Income (loss) from continuing operations attributable to common stockholders per share:					
Basic	$(2.86)	$4.02	$3.03	$4.29	$(1.65)
Diluted	$(2.86)	$3.91	$2.97	$4.24	$(1.65)
Net income (loss) attributable to common stockholders per share:					
Basic	$(6.16)	$1.54	$7.01	$5.14	$(0.46)
Diluted	$(6.16)	$1.50	$6.88	$5.08	$(0.46)
Dividends declared per share	$0.08	$0.08	$0.08	$0.08	$0.08
Balance Sheet Data (as of December 31):					
Total assets	$12,292.8	$13,069.0	$11,447.2	$9,679.1	$8,867.3
Long-term obligations	$4,427.9	$6,166.9	$4,726.5	$4,683.9	$4,653.0
Total stockholders' equity	$6,614.8	$5,867.3	$5,651.1	$4,226.0	$3,643.0

(a) During 2013 and 2011, the Company recognized impairment charges of $1.5 billion related to dry gas properties in the Raton field and $354.4 million related to its Edwards and Austin Chalk net assets in South Texas, respectively. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's impairment charges.

(b) During 2013, the Company committed to separate plans to divest of Pioneer Alaska and its assets in the Barnett Shale field. The Company recorded noncash impairment charges of $729.3 million during 2013 associated with the planned sales and $532.6 million during 2012 related to dry gas properties in the Barnett Shale field. During December 2011, the Company committed to a plan to divest Pioneer South Africa. During December 2010, the Company committed to a plan to sell Pioneer Tunisia and in February 2011 completed the sale of the Company's share holdings in Pioneer Tunisia, resulting in a gain of $645.2 million. During 2009, the Company recorded $119.3 million of income for the recovery of the excess royalties related to its Gulf of Mexico shelf properties, which were sold in 2006. The results of these operations which are in the process of being sold or were sold during the periods presented are classified as discontinued operations in accordance with GAAP. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's discontinued operations.

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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 2013 included the following highlights:

- Net loss attributable to common stockholders was $838.4 million ($6.16 per diluted share) for the year ended December 31, 2013, as compared to net income attributable to common stockholders of $192.3 million ($1.50 per diluted share) in 2012. The $1.0 billion decrease in net income attributable to common stockholders is primarily comprised of an $897.0 million decrease in income from continuing operations and a $145.4 million increase in loss from discontinued operations, net of tax.

The primary components of the decrease in net income from continuing operations include:

- a $1.5 billion impairment charge to reduce the carrying value of the Company's Raton gas field assets based on reductions in management's long-term gas price outlook (see Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and "Results of Operations" below);
- a $326.2 million decrease in net derivative gains, primarily as a result of changes in forward commodity prices and changes in the Company's portfolio of derivatives;
- a $79.1 million increase in total oil and gas production costs and production and ad valorem taxes, primarily due to a 12 percent increase in sales volumes;
- a $198.8 million increase in DD&A expense, primarily attributable to the aforementioned increase in sales volumes coupled with a decrease in Spraberry field proved undeveloped reserves as a result of removing vertical well locations that are no longer expected to be drilled as the Company shifts its capital resources to higher-rate-of-return horizontal drilling (see Supplementary Information included in "Item 8. Financial Statements and Supplementary Data");
- a $51.7 million increase in general and administrative expenses primarily due to growth in employee headcount in support of the Company's capital expansion initiatives, performance-related compensation expense and higher stock-based compensation expense associated with cash-settled restricted stock awards, which are classified as liabilities, as a result of increases in the market value of the Company's common stock; and
- a $23.2 million increase in other expense, primarily due to increases in impairment of inventory and other assets; partially offset by
- a $580.4 million increase in oil and gas revenues as a result of a 12 percent increase in total sales volumes and a 10 percent increase in average commodity prices received per BOE;
- a $502.3 million decrease in income tax provision due to the decline in income from continuing operations before income taxes;
- a $163.1 million increase in gain on disposition of assets, primarily due to the gain recorded on the Company's sale of a 40 percent interest in the Company's horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas to Sinochem; and
- a $20.5 million decrease in interest expense, primarily due to a decline in outstanding borrowings.

The primary components of the increase in the loss from discontinued operations, net of tax, include:

- a $196.7 million increase in impairment provisions associated with the planned sales of Pioneer Alaska and the Company's Barnett Shale field assets ($729.3 million) as compared to the 2012 impairment of Barnett Shale field assets included in discontinued operations ($532.6 million); and
- a $32.0 million decrease in net gains on sales of portions of the Company's discontinued operations in the Barnett Shale, Alaska and South Africa assets; partially offset by
- a $68.4 million increase in income tax benefit.

During December 2013, the Company committed to a plan to sell Pioneer Alaska and the Company's Barnett Shale field assets. In accordance with GAAP, the Company has classified Pioneer Alaska and the Barnett Shale field assets and liabilities as discontinued operations held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2013, and has recast Pioneer Alaska and the Barnett Shale field asset's results of operations as loss from discontinued operations, net of associated income taxes, in the accompanying consolidated statements of

operations included in "Item 8. Financial Statements and Supplementary Data." Loss from discontinued operations, net of tax for the year ended December 31, 2013 includes (i) recognized noncash impairment charges totaling $729.3 million representing adjustments to reduce the carrying values of Pioneer Alaska and the Company's Barnett Shale field assets to their estimated fair values, partially offset by (ii) the results of discontinued operations (see Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's discontinued operations);

- Daily sales volumes from continuing operations increased on a BOE basis by 12 percent to 161,456 BOEPD during 2013, as compared to 143,939 BOEPD during 2012, primarily due to the success of the Company's drilling programs;
- Average reported oil and gas prices from continuing operations increased during 2013 to $92.62 per BBL and $3.43 per MCF, respectively, as compared to respective average reported prices of $90.67 per BBL and $2.60 per MCF during 2012. Average reported NGL prices from continuing operations decreased during 2013 to $30.24 per BBL, as compared to an average reported price of $34.04 per BBL during 2012;
- Average oil and gas production costs per BOE from continuing operations decreased during 2013 to $10.43 as compared to per BOE costs of $10.59 during 2012, primarily due to a decrease in net natural gas plant charges as a result of higher gas prices being realized on third-party volumes that are retained as processing fees in Company-owned facilities, partially offset by higher third-party transportation charges incurred on increasing sales volumes in the Eagle Ford Shale field. See "Results of Operations" below for more information about changes in production costs;
- Net cash provided by operating activities increased by $307.7 million, or 17 percent, to $2.1 billion for 2013, as compared to $1.8 billion during 2012, primarily due to the increases in oil and gas sales volumes and prices, partially offset by a $227.6 million decrease in cash receipts on settled derivative instruments; and
- As of December 31, 2013, the Company's net debt to book capitalization declined to 25 percent, as compared to 37 percent as of December 31, 2012, primarily due to (i) the February 2013 issuance of 10.35 million shares of the Company's common stock for $1.3 billion of cash proceeds, net of associated underwriting and offering expenses, and (ii) the May 2013 completion of the sale of a 40 percent interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas for $623.8 million of cash proceeds. The Company utilized a portion of the proceeds from these items to reduce long-term debt by $1.1 billion during 2013 and increase cash and cash equivalents by $163.3 million. The long-term debt reduction during 2013 included (i) the conversion of the Company's 2.875% Convertible Senior Notes (the "Convertible Senior Notes"), (ii) the repayment and termination of Pioneer Southwest's credit facility and (iii) the repayment of all amounts outstanding on the Company's credit facility.

First Quarter 2014 Outlook

Based on current estimates, the Company expects that first quarter 2014 production will average 166,000 to 171,000 BOEPD.

First quarter production costs (including production and ad valorem taxes and transportation costs) are expected to average $13.50 to $15.50 per BOE, based on current NYMEX strip prices for oil and gas. DD&A expense is expected to average $13.50 to $15.50 per BOE.

Total exploration and abandonment expense for the quarter is expected to be $25 million to $35 million. General and administrative expense is expected to be $70 million to $75 million. Interest expense is expected to be $44 million to $49 million, and other expense is expected to be $25 million to $35 million. Accretion of discount on asset retirement obligations is expected to be $3 million to $5 million.

The Company's first quarter effective income tax rate is expected to range from 35 percent to 40 percent, assuming current capital spending plans and no significant derivative MTM changes in the Company's derivative position. Cash income taxes are expected to be $5 million to $10 million and are primarily attributable to federal alternative minimum tax and state taxes.

2014 Capital Budget

Pioneer's capital program for 2014 totals $3.3 billion, consisting of $3.0 billion for drilling operations, including budgeted land capital for existing assets, and $285 million for other property and equipment. The 2014 budget excludes acquisitions, asset retirement obligations, capitalized interest, geological and geophysical general and administrative expense and capital expenditures associated with Pioneer Alaska and Barnett Shale field assets prior to their sale.

The 2014 drilling capital of $3.0 billion continues to be focused on oil- and liquids-rich drilling, with 97 percent of the capital allocated to the Spraberry field and the Eagle Ford Shale play. Following is a breakdown of the forecasted spending by asset area:

- Spraberry field - $2.4 billion, including (i) $205 million for drilling and facilities capital in the southern Wolfcamp joint interest area and (ii) $2.2 billion of capital in the northern Spraberry/Wolfcamp acreage, which includes $1.2 billion of horizontal drilling capital, $440 million of vertical drilling capital, $400 million for infrastructure, land and science and $100 million for gas processing facilities;

- Eagle Ford Shale – $545 million, including $480 million of horizontal drilling capital and $65 million for infrastructure and land; and
- Other spending – $100 million for other existing assets.

Pioneer's budgeted expenditures for other property and equipment in 2014 include:

- Buildings and other facilities – $160 million;
- Vertical integration capital – $100 million; and
- Vehicles and other equipment – $25 million.

The 2014 capital budget is expected to be funded from a combination of cash and cash equivalents, operating cash flow, proceeds from the sale of assets held for sale or from the sale of other nonstrategic assets and, if necessary, borrowings under the Company's credit facility.

Acquisitions

During 2013, 2012 and 2011, the Company spent $76.0 million, $157.5 million and $131.9 million, respectively, to acquire primarily undeveloped acreage for future exploitation and exploration activities. The 2013 and 2012 acquisitions primarily increased the Company's acreage positions in the West Texas Spraberry field. The 2011 acquisitions primarily increased the Company's acreage positions in the South Texas Eagle Ford Shale play, Barnett Shale play and West Texas Spraberry field. During 2013, the Company completed the acquisition of all of the outstanding common units of Pioneer Southwest not already owned by the Company in exchange for 0.2325 of a share of common stock of the Company per Pioneer Southwest common unit. Additionally, in 2012, the Company acquired Premier Silica for $297.1 million. See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's acquisitions.

Divestitures and Discontinued Operations

Alaska. During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer Alaska. The sale of Pioneer Alaska continues to be subject to ongoing negotiations and certain other conditions, such as governmental approvals and buyer's arrangement of financing. Associated with the planned sale of Pioneer Alaska, the Company recorded a noncash impairment charge of $539.8 million in discontinued operations during December 2013 to reduce the carrying value of Pioneer Alaska to its estimated fair value less costs to sell of $350.6 million. The Company has classified Pioneer Alaska assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and has reported Pioneer Alaska's historical results of operations, and the related impairment loss, as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

Barnett Shale. During the fourth quarter of 2013, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. The plan is expected to result in the sale of the Company's Barnett Shale net assets during 2014. The Company has classified its Barnett Shale field assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and has reported the Company's Barnett Shale field historical results of operations, and the related impairment loss, as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

Associated with the plan to sell its net assets in the Barnett Shale field, the Company recorded a noncash impairment charge of $189.5 million in discontinued operations during December 2013 to reduce the carrying value of its net assets in the Barnett Shale to their estimated fair value less costs to sell. Also included in discontinued operations in 2013 is the sale of the Company's interest in certain proved and unproved oil and gas properties in the Barnett Shale field for net cash proceeds of $33.8 million, which resulted in a gain of $8.7 million on the unproved properties sold.

Sendero. During December 2013, the Company committed to a plan to sell its majority interest in Sendero (the Company's vertical drilling rig subsidiary) to Sendero's minority interest owner for $31.0 million, subject to negotiating a definitive sales agreement and the buyer completing its financing arrangements. The Company classified these assets and liabilities as held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2013.

The Company's plans to sell Pioneer Alaska, the Barnett Shale net assets and Sendero are in various stages of marketing or negotiation. No assurance can be given that the sales will be completed in accordance with the Company's plans.

Southern Wolfcamp. In January 2013, the Company signed an agreement with Sinochem to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field for total consideration of $1.8 billion. In May 2013, the Company completed the sale to Sinochem for net cash proceeds of $623.8 million, resulting in a gain of $181.3 million. Sinochem is paying the remaining $1.2 billion of the transaction price by

carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play.

Pioneer South Africa. During December 2011, the Company committed to a plan to sell Pioneer South Africa. During the first quarter of 2012, the Company agreed to sell Pioneer South Africa to an unaffiliated third party, effective January 1, 2012, for $60.0 million of cash proceeds before normal closing and other adjustments, and the buyer's assumption of certain liabilities of the Company's South Africa subsidiaries. In August 2012, the Company completed the sale of Pioneer South Africa for net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a gain of $28.6 million. Pioneer South Africa's historical results of operations, and the related gain recorded on the disposition of Pioneer South Africa, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

Pioneer Tunisia. During December 2010, the Company committed to a plan to sell Pioneer Tunisia. In February 2011, the Company sold its share holdings in Pioneer Tunisia for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a gain of $645.2 million. Pioneer Tunisia's historical results of operations, and the related gain recorded on the disposition of Pioneer Tunisia, are reported as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's divestitures and discontinued operations.

Results of Operations

Oil and gas revenues. Oil and gas revenues from continuing operations totaled $3.2 billion, $2.6 billion and $2.1 billion during 2013, 2012 and 2011, respectively.

The increase in 2013 oil and gas revenues relative to 2012 is reflective of 22 percent and 20 percent increases in oil and NGL sales volumes, respectively, and two percent and 32 percent increases in average reported oil and gas prices, respectively. Partially offsetting the effects of these increases was a decline of 11 percent in average reported NGL prices.

The increase in 2012 oil and gas revenues relative to 2011 is reflective of 61 percent, 28 percent and 8 percent increases in oil, NGL, and gas sales volumes, respectively. Partially offsetting the effects of these production increases were declines of six percent, 26 percent and 33 percent in average reported oil, NGL and gas prices, respectively.

The following table provides average daily sales volumes from continuing operations for 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Oil (BBLs)	69,527	57,165	35,587
NGLs (BBLs)	32,422	27,060	21,119
Gas (MCF)	357,044	358,284	332,866
Total (BOE)	161,456	143,939	112,184

Average daily BOE sales volumes from continuing operations in 2013 and 2012 increased by 12 percent and 28 percent, respectively, as compared to the daily sales volumes in the respective prior years, principally due to the Company's successful drilling programs. In 2012, the increase in average daily BOE sales was also attributable to declines in scheduled VPP deliveries. All VPP production volumes were delivered as of December 31, 2012 and there are no further obligations under the VPP contracts.

Production for the year ended December 31, 2013 was negatively impacted by (i) gas processing capacity limitations in the Spraberry field as a result of wet gas production for the Company and other industry participants growing faster than anticipated and (ii) severe winter weather during the fourth quarter. New Spraberry field gas processing facilities were completed and began processing gas in mid-April 2013. The gas processing capacity limitations negatively impacted sales volumes by approximately 600 BOEPD for the year ended December 31, 2013. Additionally, 2013 production was reduced by approximately 1,500 BOEPD, related to heavy icing and low temperatures during the

fourth quarter primarily across Pioneer's leasehold position in the Spraberry/Wolfcamp area that resulted in extensive power outages, facility freeze-ups, trucking curtailments and limited access to production and drilling facilities. All of the affected wells have since been returned to production.

Production growth for 2012, as compared to 2011, was negatively impacted by gas processing capacity limitations in the Spraberry field as a result of wet gas production for the Company and other industry participants growing faster than anticipated. The gas processing capacity limitations negatively impacted average 2012 sales volumes by approximately 1,450 BOEPD.

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The following table provides average daily sales volumes from discontinued operations by geographic area and in total during 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Oil (BBLs):			
United States	5,693	5,480	5,031
South Africa	—	428	530
Tunisia	—	—	547
Worldwide	5,693	5,908	6,108
NGL (BBLs):			
United States	3,193	2,756	1,368
Worldwide	3,193	2,756	1,368
Gas (MCF):			
United States	23,443	20,085	11,013
South Africa	—	10,340	20,570
Tunisia	—	—	496
Worldwide	23,443	30,425	32,079
Total (BOE):			
United States	12,793	11,583	8,234
South Africa	—	2,151	3,958
Tunisia	—	—	630
Worldwide	12,793	13,734	12,822

The oil, NGL and gas prices that the Company reports are based on the market prices received for the commodities. The following table provides the Company's average prices from continuing operations for 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012 (a)	2011 (a)
Oil (per BBL)	$92.62	$90.67	$96.60
NGL (per BBL)	$30.24	$34.04	$46.31
Gas (per MCF)	$3.43	$2.60	$3.86
Total (per BOE)	$53.55	$48.88	$50.80

(a) For the years ended December 31, 2012 and 2011, the Company's average realized oil prices per BBL were $88.81 and $90.61, respectively, and the average realized prices per BOE for the years ended December 31, 2012 and 2011 were $48.15 and $48.90, respectively. The average realized prices do not include the impact of transfers of the Company's deferred hedge gains and losses from Accumulated Other Comprehensive Income ("AOCI-Hedging") and the amortization of deferred VPP revenue. During the year ended December 31, 2012 and 2011, the Company transferred $3.2 million of deferred oil hedge losses and $32.9 million of deferred oil hedge gains, respectively, from AOCI-Hedging to oil revenue. The 2012 transfer represented all of the remaining AOCI-Hedging transfers to earnings. Amortization of deferred VPP revenue increased oil revenues by $42.1 million and $45.0 million during the years ended December 31, 2012 and 2011, respectively. As of December 31, 2012, all VPP production volumes had been delivered and there are no further obligations under VPP contracts.

Sales of purchased oil and gas. The Company periodically enters into pipeline capacity commitments in order to secure available oil and gas transportation capacity from the Company’s areas of production. The Company enters into oil and gas purchase transactions with third parties and separate sale transactions with third parties to satisfy unused

pipeline capacity commitments and to diversify a portion of the Company's WTI oil sales to a Gulf Coast oil price. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming the risk and rewards of ownership, including credit risk, of the oil and gas purchased and assuming responsibility to deliver the oil and gas volumes sold. Deficiency payments on excess pipeline capacity are included in other expense in the accompanying consolidated statements of operations. See Note N of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for further information on transportation commitment charges.

Interest and other income. The Company's interest and other income from continuing operations was $17.0 million and $29.4 million during 2013 and 2011, respectively, and a loss of $1.0 million in 2012. The $18.0 million increase during 2013, as compared to 2012, is primarily attributable to a $7.1 million reduction in losses from vertical integration services, a $5.1 million increase in equity in earnings of EFS Midstream and $4.1 million of gains on deferred compensation plan assets. The $30.4 million decrease during 2012, as compared to 2011, is primarily attributable to a $27.9 million decrease in income from vertical integration services. See Note M of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's interest and other income.

Derivative gains (losses), net. 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, sells or consumes, (ii) support the Company's annual capital budgeting and expenditure plans and (iii) reduce commodity price risk associated with certain capital projects. In 2009, the Company discontinued hedge accounting on all of its then-existing derivative contracts. Changes in the fair value of effective cash flow hedges prior to the Company's discontinuance of hedge accounting were recorded as a component of AOCI – Hedging in the equity section of the Company's consolidated balance sheets, and were transferred to earnings during the same periods in which the hedged transactions were recognized in the Company's earnings. Since 2009, the Company has recognized all changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which they occur. All deferred oil hedge losses were transferred from AOCI-Hedging to earnings during the year ended December 31, 2012. Transfers of deferred hedge gains and losses associated with oil cash flow hedges from AOCI – Hedging to oil revenues for the years ended December 31, 2012 and 2011 resulted in a decrease of $3.2 million and an increase of $32.9 million, respectively, to oil revenue.

The following table summarizes the Company's net derivative gains or losses for the years ending December 31, 2013, 2012 and 2011 (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Noncash changes in fair value:			
Oil derivative gains (losses)	$(18,855)	$217,765	$68,376
NGL derivative gains (losses)	(616)	1,209	10,243
Gas derivative gains (losses)	(153,993)	(290,058)	179,787
Diesel derivative gains (losses)	—	(270)	270
Marketing derivative gains (losses)	22	(22)	—
Interest rate derivative gains (losses)	9,321	5,930	(33,206)
Total noncash derivative gains (losses), net	(164,121)	(65,446)	225,470
Net cash receipts (payments) on settled derivative instruments:			
Oil derivative receipts (payments)	11,579	4,139	(36,664)
NGL derivative receipts (payments)	1,224	13,403	(15,418)
Gas derivative receipts	155,014	402,981	183,010
Diesel derivative receipts	—	3,497	67
Marketing derivative receipts (payments)	(168)	36	(17)
Interest rate derivative receipts (payments)	482	(28,359)	36,304
Total cash receipts on settled derivative instruments, net	168,131	395,697	167,282
Total derivative gains, net	$4,010	$330,251	$392,752

The Company's open derivative contracts are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's derivative contracts.

Gain (loss) on disposition of assets. The Company recorded net gains of $209.0 million and $45.9 million during 2013 and 2012, respectively, and a net loss on the disposition of assets of $3.6 million during 2011.

During 2013, the Company's primary gains on disposition of assets included a $181.3 million gain on the sale of a 40 percent interest in the Company's horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas to Sinochem and a gain of $22.4 million on the sale of the Company's interest in unproved oil and gas properties adjacent to the Company's West Panhandle field operations. During 2012, the Company recorded a $42.6 million gain on the sale of a portion of its interest

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in an unproved oil and gas property in the Eagle Ford Shale field. During 2011, the net loss was primarily associated with losses on the sales of excess materials and supplies inventory, partially offset by gains on the sale of certain unproved properties.

Oil and gas production costs. The Company's oil and gas production costs from continuing operations totaled $614.7 million, $558.0 million and $397.0 million during 2013, 2012 and 2011, 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 oil and gas production costs per BOE for the year ended December 31, 2013 decreased by two percent as compared to 2012. The decrease in production costs per BOE during 2013 is primarily reflective of a $0.44 per BOE decrease in net natural gas plant charges as a result of higher gas prices being realized on third-party volumes that are retained as processing fees in Company-owned facilities. Partially offsetting the decrease in per BOE net natural gas plant charges was a $0.25 per BOE increase in third-party transportation charges, primarily associated with increasing Eagle Ford Shale sales volumes.

During 2012, total production costs per BOE increased by nine percent as compared to 2011. The increase in production costs per BOE during 2012 is primarily reflective of increases in lease operating expenses, third-party transportation charges and net natural gas plant/gathering charges. Lease operating costs increased by $0.32 per BOE during 2012 primarily due to an increase in salt water disposal costs (principally comprised of water hauling fees). The $0.17 per BOE increase in third-party transportation charges during 2012 is primarily due to gathering, treating and transportation costs associated with increasing sales volumes from the Company's successful drilling program in the Eagle Ford Shale field. Net natural gas plant charges increased by $0.38 per BOE during 2012 primarily due to a reduction in third-party revenues from processing third-party gas volumes in Company-owned facilities as a result of lower gas and NGL prices being realized on the volumes retained as a processing fee.

The following table provides the components of the Company's total production costs per BOE for 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Lease operating expenses	$8.00	$7.91	$7.59
Third-party transportation charges	1.56	1.31	1.14
Net natural gas plant/gathering charges	0.10	0.54	0.16
Workover costs	0.77	0.83	0.80
Total production costs	$10.43	$10.59	$9.69

Production and ad valorem taxes. The Company recorded production and ad valorem taxes of $201.2 million during 2013, as compared to $178.7 million and $139.4 million for 2012 and 2011, respectively. 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. Production and ad valorem taxes on a per BOE basis have been relatively stable since 2011.

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 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Production taxes	$2.20	$2.17	$2.23
Ad valorem taxes	1.22	1.22	1.17
Total ad valorem and production taxes	$3.42	$3.39	$3.40

Depletion, depreciation and amortization expense. The Company's total DD&A expense from continuing operations was $907.1 million ($15.39 per BOE), $708.3 million ($13.44 per BOE), and $489.6 million ($11.96 per BOE) for 2013, 2012 and 2011, respectively. Depletion expense on oil and gas properties, the largest component of DD&A expense, was $14.70, $12.82 and $11.33 per BOE during 2013, 2012 and 2011, respectively.

During 2013, the 15 percent increase in per BOE depletion expense, as compared to that of 2012, is primarily due to (i) capital expenditures to develop proved undeveloped locations, primarily in the Company's successful Spraberry and Eagle Ford Shale fields programs and (ii) a 22 percent decline in total proved reserves. The decline in total proved reserves is primarily

comprised of negative revisions of previous estimates to remove undeveloped vertical well locations that are no longer expected to be drilled as the Company shifts its planned capital expenditures to higher-rate-of-return horizontal drilling, partially offset by a nine percent increase in proved developed reserves.

During 2012, the 13 percent increase in per BOE depletion expense was primarily due to (i) increased drilling expenditures on proved undeveloped locations, primarily in the Spraberry field and (ii) declines in proved gas reserves due to lower first-day-of-the-month gas prices during the twelve month period ending on December 31, 2012, partially offset by (iii) the impairment effects of reducing carrying values of the South Texas Edwards Trend/Austin Chalk fields during 2012 and 2011, respectively (see the discussion below for more information on the Company's impairment charges).

Impairment of oil and gas properties and other long-lived assets. The Company recorded impairment expense in continuing operations to reduce the carrying values of oil and gas properties by $1.5 billion and $354.4 million during the years ended December 31, 2013 and 2011, respectively.

The Company performs assessments of its long-lived assets to be held and used, including oil and gas properties, whenever events or circumstances indicate that the carrying values of those assets may not be recoverable. In order to perform these assessments, management uses various observable and unobservable inputs, including management's outlooks for (i) commodity prices, (ii) production costs, (iii) capital expenditures and (iv) production, based upon current estimates of proved reserves and risk-adjusted probable reserves.

Management's commodity price outlooks represent longer-term outlooks that are developed based on third-party longer-term commodity futures price outlooks as of a measurement date ("Management's Price Outlooks"). During 2013, 2012 and 2011, declines in Management's Price Outlooks for gas provided indications of possible impairment of the Company's predominantly dry gas properties in the Raton field in southeastern Colorado, the Barnett Shale field in North Texas (classified as held for sale as of December 31, 2013) and the Edwards Trend and Austin Chalk fields in South Texas, respectively. During the years ended December 31, 2013 and 2012, Management's Price Outlook for gas declined by 10 percent and four percent, respectively, and Management's Price Outlook for oil declined by seven percent for both periods. The trend of Management's Price Outlooks by quarter during 2013 is as follows:

	December 31, 2013	September 30, 2013	June 30, 2013	March 31, 2013	December 31, 2012
Management's gas outlook	$4.43	$4.93	$5.43	$4.81	$4.92
Management's oil outlook	$80.40	$83.24	$80.65	$85.13	$86.40

As a result of management's assessments, during 2013, 2012 and 2011, the Company recognized noncash impairment charges of $1.5 billion, $532.6 million and $354.4 million to reduce the carrying values of the Company's Raton field assets, the Company's Barnett Shale field assets (which are now classified as discontinued operations in the accompanying statements of operations) and the Edwards Trend/Austin Chalk field assets, respectively, to their estimated fair values.

Declines in Management's Price Outlooks during 2013 also provided an indication that the Company's Hugoton field assets in southwest Kansas may have been impaired. The Company's estimates of undiscounted future net cash flows attributable to the Hugoton field assets indicated that on December 31, 2013 their carrying amounts are expected to be recovered, but continue to be at risk for impairment if estimates of future cash flows decline. For example, the Company estimates that the carrying value of the Hugoton field may become partially impaired if the average price in Management's Price Outlook for gas were to decline by approximately $0.30 to $0.50 per MCF. The Company estimates that if the Hugoton field were to become impaired in a future period, the Company would recognize noncash impairment charges in that period that could range from $200 million to $250 million.

It is reasonably possible that the estimate of undiscounted future net cash flows attributable to these or other properties may change in the future resulting in the need to impair their carrying values. The primary factors that may affect estimates of future cash flows are (i) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves (ii) results of future drilling activities, (iii) Management's Price Outlooks and (iv) increases or decreases in production and capital costs associated with these fields.

See Notes B and D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's impairment assessments.

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Exploration and abandonments expense. The following table provides the Company's geological and geophysical costs, exploratory dry holes expense and leasehold abandonments and other exploration expense from continuing operations for 2013, 2012 and 2011 (in thousands):

	Year Ended December 31,		
	2013	2012	2011
Geological and geophysical	$77,005	$66,908	$48,092
Exploratory dry holes	5,876	9,016	2,864
Leasehold abandonments and other	15,567	22,361	29,735
	$98,448	$98,285	$80,691

During 2013, the Company's exploration and abandonment expense was primarily attributable to $77.0 million of geological and geophysical costs, of which $58.0 million was geological and geophysical administrative costs; $5.9 million of dry hole provisions; and $15.5 million of leasehold abandonment expense, which included $14.3 million associated with the Company's unproved dry gas properties in the Eagle Ford Shale and other unproved property abandonments. During 2013, the Company completed and evaluated 253 exploration/extension wells, 244 of which were successfully completed as discoveries.

During 2012, the Company's exploration and abandonment expense was primarily attributable to $66.9 million of geological and geophysical costs, of which $42.0 million was geological and geophysical administrative costs; $9.0 million of dry hole provisions; and $22.2 million of leasehold abandonment expense. The significant components of the Company's 2012 leasehold abandonment expense included $9.5 million in the Eagle Ford Shale area, $4.8 million in the Rockies area and $4.7 million in the Permian Basin. During 2012, the Company completed and evaluated 229 exploration/extension wells, 223 of which were successfully completed as discoveries.

During 2011, the Company's exploration and abandonment expense was primarily attributable to $48.1 million of geological and geophysical costs, of which $32.0 million was geological and geophysical administrative costs, and $29.7 million of leasehold abandonment expense. The significant components of the Company's 2011 leasehold abandonment expense included dry gas unproved acreage abandonments of $9.3 million in the South Texas area and $9.1 million in the Rockies area. During 2011, the Company completed and evaluated 168 exploration/extension wells, 167 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense from continuing operations totaled $295.9 million, $244.2 million and $190.0 million during 2013, 2012 and 2011, respectively. The increase in 2013, as compared to 2012, is primarily due to increases of $42.7 million and $3.3 million in compensation and occupancy expenses, respectively, related to staffing increases in support of the Company's capital expansion and integrated services initiatives. The $42.7 million increase in compensation expense includes a $7.6 million increase in stock-based compensation expense associated with Liability Awards, primarily due to increases in the market value of the Company's common stock during 2013, and an $18.9 million increase in cash bonus expense payable to employees as a result of the accomplishments of the Company during 2013.

The increase in general and administrative expense during 2012, as compared to 2011, was also primarily due to increases of $45.7 million and $4.7 million in compensation and occupancy expenses, respectively, related to staffing increases in support of the Company's capital expansion and integrated services initiatives.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations from continuing operations was $11.9 million, $8.7 million and $7.5 million during 2013, 2012 and 2011, respectively. The 37 percent and 16 percent increases in accretion of discount on asset retirement obligations during 2013 and 2012, respectively, are primarily due to additional well completions resulting from the Company's drilling activities. 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 asset retirement obligations.

Interest expense. Interest expense was $183.8 million, $204.2 million and $181.6 million during 2013, 2012 and 2011, respectively. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2013 was 6.5 percent, as compared to 6.0 percent and 7.2 percent for the years ended December 31, 2012 and 2011,

respectively.

The decrease in interest expense during 2013, as compared to 2012, was primarily due to a decrease in debt as a result of the repayment of amounts outstanding under Pioneer Southwest's credit facility and conversions of Convertible Senior Notes, and a decrease of $18.3 million in noncash amortization of financing fees, debt issuance discounts and deferred hedge losses.

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The $22.6 million increase in interest expense during 2012, as compared to 2011, is primarily due to an $868.9 million increase in the Company's average outstanding indebtedness, partially offset the 1.2 percent decline in weighted average interest on indebtedness.

See Note G 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.

Other expenses. Other expenses from continuing operations were $137.4 million during 2013, as compared to $114.2 million during 2012 and $63.1 million during 2011. The $23.2 million increase in other expense during 2013, as compared to 2012, is primarily associated with (i) $25.5 million of impairment associated with the planned sale of the Company's majority interest in Sendero, (ii) a $30.6 million increase in inventory valuation allowances and (iii) an $8.8 million increase in contingency and environmental accrual adjustments, partially offset by (iv) a $23.4 million decrease in above market and idle drilling and well service equipment charges and (v) a $14.7 million decrease in terminated drilling rig contract charges.

The $51.1 million increase in other expense during 2012, as compared to 2011, is primarily due to $15.7 million of contract rig termination fees incurred during 2012, a $15.0 million increase in unused gas transportation commitment charges and a $13.0 million increase in above market and idle drilling and well service equipment charges, which are not chargeable to joint operations.

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

Income tax provision. The Company recognized an income tax benefit attributable to earnings from continuing operations of $211.8 million during 2013, as compared to income tax provisions of $290.5 million and $188.3 million during 2012 and 2011, respectively. The Company's effective tax rates on earnings from continuing operations, excluding income from noncontrolling interest, for 2013, 2012 and 2011 were 35 percent, 37 percent and 34 percent, respectively, as compared to the combined United States federal and state statutory rates of approximately 36 percent. See "Critical Accounting Estimates" below and Note O of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's income tax rates and attributes.

Income (loss) from discontinued operations, net of tax. The Company recognized a loss from discontinued operations, net of tax, of $449.6 million in 2013 as compared to a loss of $304.2 million for 2012 and income of $474.1 million for 2011. Income (loss) from discontinued operations, net of tax includes the operations of the following:

- Pioneer Alaska which was placed into assets held for sale and discontinued operation in December 2013,
- The Barnett Shale field assets which were placed into assets held for sale and discontinued operation in December 2013,
- Pioneer South Africa which was placed into assets held for sale and discontinued operation in December 2011; and
- Pioneer Tunisia which was placed into assets held for sale and discontinued operations in December 2010.

The $145.4 million increase in loss from discontinued operations, net of tax during 2013, as compared to 2012 is primarily attributable to the increase in impairments of net assets. In 2013, the Company had total impairments of Pioneer Alaska and Barnett Shale assets of $729.3 million, compared to impairment charges of $532.6 million on Barnett Shale assets in 2012. The $778.3 million decrease in income from discontinued operations, net of tax during 2012, as compared to 2011 is primarily attributable to the after tax gain on the sale of Pioneer Tunisia recorded in 2011 and the 2012 impairment of Barnett Shale field assets.

See Note C 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 attributable to noncontrolling interest. Net income attributable to noncontrolling interests was $38.9 million, $50.5 million and $47.4 million for the years ended December 31, 2013, 2012 and 2011, respectively. The Company's net income attributable to noncontrolling interest is primarily associated with the net income of Pioneer Southwest that was allocated to limited partners, through December 17, 2013, the date of the Pioneer Southwest merger. The $11.6 million decrease in net income attributable to noncontrolling interest in 2013, as compared to 2012,

is primarily due to decreases in Pioneer Southwest's noncash derivative gains, higher production costs and higher depletion expense, partially offset by increased revenues.

The $3.1 million increase in net income attributable to noncontrolling interest in 2012, as compared to 2011, is primarily due to a 10 percent increase in noncontrolling interest in Pioneer Southwest during November 2011 as a result of an offering by Pioneer Southwest of 4.4 million common units, representing limited partnership units, of which 1.8 million common units were

sold by the Company. Partially offsetting the increase in noncontrolling interest in Pioneer Southwest was a $15.3 million decline in Pioneer Southwest's net income during 2012, as compared to 2011. See Note B of Notes to Consolidated Financial Statements included in "Item 8. 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 properties and related vertical integration assets and facilities, payments of contractual obligations, dividends and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, cash and cash equivalents on hand, proceeds from the sale of nonstrategic assets or external financing sources as discussed in "Capital resources" below. During 2014, the Company expects that it will be able to fund its needs for cash (excluding acquisitions, if any) with a combination of internally generated cash flows, cash and cash equivalents on hand, proceeds from the divestiture of assets held for sale, proceeds from the sale of other nonstrategic assets and, if necessary, availability under the Company's credit facility. Although the Company expects that these sources of funding will be adequate to fund capital expenditures and dividend payments and 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.

During 2014, the Company plans to continue to focus its capital spending primarily on liquids-rich drilling activities. The Company's 2014 capital budget totals $3.3 billion (excluding acquisitions, asset retirement obligations, capitalized interest, geological and geophysical administrative costs and capital expenditures associated with Pioneer Alaska and Barnett Shale field assets prior to their sale), consisting of $3.0 billion for drilling operations and $285 million for buildings, vertical integration and other plant and equipment additions. Based on the Company's current Management Price Outlooks, Pioneer expects its net cash flows from operating activities, cash and cash equivalents on hand, proceeds from the divestiture of assets held for sale, proceeds from other nonstrategic assets sales and, if necessary, availability under the Company's credit facility to be sufficient to fund its planned capital expenditures and contractual obligations.

Investing activities. Net cash used in investing activities during 2013 was $2.1 billion, as compared to net cash used in investing activities of $3.3 billion and $1.6 billion during 2012 and 2011, respectively. The decrease in net cash flow used in investing activities during 2013, as compared to 2012, is primarily due to (i) a $615.5 million increase in proceeds from disposition of assets, which resulted from $623.8 million of net cash proceeds from the May 2013 sale to Sinochem of a 40 percent interest in the Company's horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas, (ii) a $297.1 million decrease in payments for acquisitions due to the acquisition of Premier Silica during 2012, (iii) a $119.3 million decrease in additions to oil and gas properties, partially due to the drilling carry being paid by Sinochem in the southern portion of the horizontal Wolfcamp Shale play, (iv) a $59.7 million decrease in additions to other assets and other property and equipment and (v) a $25.1 million distribution from EFS Midstream during December 2013. In addition to the aforementioned proceeds from disposition of assets, the Company's investing activities during the year ended December 31, 2013 were funded by net cash provided by operating activities.

The increase in net cash flow used in investing activities during 2012, as compared to 2011, was primarily due to (i) an $831.1 million increase in additions to oil and gas properties associated with the Company's capital programs, (ii) a $723.5 million decrease in proceeds from disposition of assets (primarily attributable to the 2011 sale of Pioneer Tunisia, partially offset by proceeds from the sales of Pioneer South Africa and a partial interest in certain Eagle Ford Shale unproved leaseholds during 2012) and (iii) the $297.1 million of cash used for the acquisition of Premier Silica, partially offset by (iv) an $89.6 million decrease in investments in EFS Midstream and (v) a $66.4 million decrease in additions to other assets and other property and equipment. See "Results of Operations" above and Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding asset divestitures.

Dividends/distributions. During each of the years ended December 31, 2013, 2012 and 2011, the Board declared semiannual dividends of $0.04 per common share. Associated therewith, the Company paid $11.1 million, $10.0 million and $9.6 million, respectively, of aggregate dividends. 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 of 2013, 2012 and 2011, the board of directors of the general partner of Pioneer Southwest declared quarterly distributions aggregating annually to $2.08, $2.07 and $2.03 per limited partner unit, respectively. Associated therewith, Pioneer Southwest paid aggregate distributions to noncontrolling unitholders of $35.3 million, $35.2 million and $25.6 million during the years ended December 31, 2013, 2012 and 2011, respectively.

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, 2013, the material

off-balance sheet arrangements and transactions that the Company has entered into include (i) operating lease agreements, (ii) drilling commitments (iii) firm transportation and fractionation commitments, (iv) open purchase commitments and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, fractionation and transportation commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. 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 and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" 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), capital funding obligations, derivative obligations, other liabilities (including postretirement benefit obligations), firm transportation and fractionation commitments and minimum annual gathering, treating and transportation commitments. Other joint owners in the properties operated by the Company will incur portions of the costs represented by these commitments.

The following table summarizes by period the payments due by the Company for contractual obligations estimated as of December 31, 2013:

	Payments Due by Year			
	2014	2015 and 2016	2017 and 2018	Thereafter
	(in thousands)			
Long-term debt (a)	$—	$455,385	$934,600	$1,300,000
Operating leases (b)	25,305	34,630	31,055	26,569
Drilling commitments (c)	189,987	172,846	—	—
Derivative obligations (d)	11,626	—	2,357	7,576
Open purchase commitments (e)	232,351	5,084	—	—
Other liabilities (f)	46,873	44,576	41,767	166,685
Firm gathering, processing and transportation commitments (g)	353,167	823,157	527,327	773,868
	$859,309	$1,535,678	$1,537,106	$2,274,698

(a) See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for information regarding estimated future interest payment obligations under long-term debt obligations. The amounts included in the table above represent principal maturities only.

(b) See Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the Company's operating leases.

(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, 2013.

(d) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity and interest rate derivatives that were valued as of December 31, 2013. The ultimate settlement amounts of the Company's derivative obligations are unknown because they are subject to continuing market risk. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and Note E 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, materials and other property and equipment ordered, but not received, as of December 31, 2013.

(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 J 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, asset retirement obligations and litigation and environmental contingencies, respectively.

(g) Gathering, processing and transportation commitments represent estimated fees on production throughput commitments and demand fees associated with volume delivery commitments of up to 50,000 BOEPD through August 2017 that are related to the Company's Permian Basin operations. The Company does not expect to be able to fulfill all of its short-term and long-term delivery obligations from projected production of available reserves; consequently, the Company plans to

purchase third party volumes to satisfy its commitments if it is economic to do so; otherwise, it will pay demand fees for commitment shortfalls. See "Item 2. Properties" and Note J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's gathering, processing and transportation commitments.

Capital resources. The Company's primary capital resources are cash and cash equivalents, net cash provided by operating activities, proceeds from sales of joint interests and nonstrategic assets and proceeds from financing activities (principally borrowings under the Company's credit facility or issuances of debt or equity securities). If internal cash flows and cash on hand do not meet the Company's expectations, the Company may reduce its level of capital expenditures, and/or fund a portion of its capital expenditures using availability under the Company's credit facility, issue debt or equity securities or obtain capital from other sources, such as through sales of nonstrategic assets.

Operating activities. Net cash provided by operating activities for the years ended December 31, 2013, 2012 and 2011 was $2.1 billion, $1.8 billion and $1.5 billion, respectively. The increase in net cash flow provided by operating activities in 2013 was primarily due to an increase in oil and gas sales, partially offset by a decrease in net cash receipts from derivative settlements. The increase in net cash flow provided by operating activities in 2012 was primarily due to increases in oil and gas sales and net cash receipts from derivative settlements.

Asset divestitures. During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer Alaska. The sale of Pioneer Alaska continues to be subject to ongoing negotiations and certain other conditions, such as governmental approvals and buyer's arrangement of financing. Associated with the planned sale of Pioneer Alaska, the Company recorded a noncash impairment charge of $539.8 million in discontinued operations during December 2013 to reduce the carrying value of the Pioneer Alaska assets to their estimated fair value less costs to sell of $350.6 million. The Company has classified Pioneer Alaska assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and has reported Pioneer Alaska's historical results of operations, and the related impairment loss, as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

During the fourth quarter of 2013, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. The plan is expected to result in the sale of the Barnett Shale net assets during 2014. The Company has classified Barnett Shale assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and has reported Barnett Shale historical results of operations, and the related impairment loss, as discontinued operations, net of tax in the Company's accompanying consolidated statements of operations.

Associated with the plan to sell its net assets in the Barnett Shale field, the Company recorded a noncash impairment charge of $189.5 million in discontinued operations during December 2013 to reduce the carrying value of its net assets in the Barnett Shale field to their estimated fair value less costs to sell. See Note D for more information about the impairment of the Company's Barnett Shale field net assets. Also included in discontinued operations in 2013 is the sale of the Company's interest in certain proved and unproved oil and gas properties in the Barnett Shale field for net cash proceeds of $33.8 million, which resulted in a gain of $8.7 million on the unproved properties sold.

During December 2013, the Company committed to a plan to sell its majority interest in Sendero (the Company's vertical drilling rig subsidiary) to Sendero's minority interest owner for $31.0 million, subject to negotiating a definitive sales agreement and the buyer completing its financing arrangements. The Company classified these assets and liabilities as held for sale in the Company's accompanying consolidated balance sheet as of December 31, 2013.

The Company's plans to sell Pioneer Alaska, the Barnett Shale net assets and Sendero are in various stages of marketing or negotiation. No assurance can be given that the sales will be completed in accordance with the Company's plans.

In January 2013, the Company signed an agreement with Sinochem to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field for consideration of $1.8 billion. In May 2013, the Company completed the sale to Sinochem for net cash proceeds of $623.8 million, resulting in a gain of $181.3 million related to the unproved property interests conveyed to Sinochem.

Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play.

During the first quarter of 2012, the Company agreed to sell Pioneer South Africa to an unaffiliated third party for $60.0 million of cash proceeds before normal closing and other adjustments, and the buyer's assumption of certain liabilities of the Company's South Africa subsidiaries. In August 2012, the Company completed the sale of Pioneer South Africa for net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a gain of $28.6 million. During 2011, the Company completed the sale of Pioneer Tunisia

to an unaffiliated party for cash proceeds of $802.5 million, excluding cash and cash equivalents sold, resulting in a gain of $645.2 million.

See Note C of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information regarding the Company's divestitures.

Financing activities. Net cash provided by financing activities during 2013 was $157.8 million, as compared to net cash provided by financing activities during 2012 and 2011 of $1.1 billion and $457.4 million, respectively. During 2013, the significant components of financing activities included $1.1 billion of net payments on long-term debt, the Company's completion of an offering of 10.35 million shares of its common stock in February 2013 at a per-share price, after underwriting and offering expenses, of $123.76 for a total of $1.3 billion of realized net proceeds and $47.2 million of dividend payments and distributions to noncontrolling interests. During 2012, the significant components of financing activities included $1.2 billion of net borrowings on long-term debt and $45.9 million of dividend payments and distributions to noncontrolling interests. During 2011, significant components of financing activities included $484.2 million of net proceeds received from the offering of 5.5 million shares of the Company's common stock and $123.0 million of net proceeds received from the sale of 4.4 million common units representing limited partner interests in Pioneer Southwest, partially offset by $98.3 million of net principal payments on long-term debt and $36.3 million of dividend payments and distributions to noncontrolling interests.

The following provides a description of the Company's significant financing activities during 2013, 2012 and 2011:

- During December 2012 and March 2013, respectively, the Company's stock price met the price threshold that caused the Convertible Senior Notes to be convertible during the six months ended June 30, 2013 at the option of the holders into a combination of cash and the Company's common stock based on a formula set forth in the indenture supplement pursuant to which the Convertible Senior Notes were issued. On April 15, 2013, the Company announced that it would exercise its option to redeem all Convertible Senior Notes that had not been converted by the holders before May 16, 2013. Holders of $479.1 million principal amount of the Convertible Senior Notes exercised their right to convert their Convertible Senior Notes into cash and shares of the Company's common stock. The Company paid the tendering holders $479.1 million of cash and issued to the tendering holders 4.4 million shares of the Company's common stock in accordance with the terms of the Convertible Senior Notes indenture agreement. On May 16, 2013, the Company paid $845 thousand in principal and interest to redeem all Convertible Senior Notes that remained outstanding.
- During February 2013, the Company completed the sale of 10.35 million shares of its common stock for $1.3 billion of net cash proceeds.
- During December 2012, the Company amended its credit facility with a syndicate of financial institutions to increase the aggregate loan commitments to $1.5 billion from $1.25 billion and extend its maturity to December 2017;
- During June 2012, the Company issued $600 million of 3.95% Senior Notes due 2022 and received proceeds, net of $8.5 million of offering discounts and costs, of $591.5 million;
- During December 2011, Pioneer Southwest completed the public offering of 4.4 million common units of Pioneer Southwest, representing limited partnership interests, at a per-unit price of $29.20, before offering costs. Of the 4.4 million common units, Pioneer sold 1.8 million of its Pioneer Southwest common unit holdings for net proceeds of $50.5 million and Pioneer Southwest issued 2.6 million new common units for net proceeds of $72.5 million, including offering costs. Pioneer Southwest used its net proceeds to reduce its credit facility borrowings; and
- During November 2011, the Company completed the sale of 5.5 million shares of its common stock for $484.2 million of net proceeds.

See Note G 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 as 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 sources of short-term liquidity are cash and cash equivalents and unused borrowing capacity under the Company's credit facility. As of December 31, 2013, the Company had no outstanding borrowings under the credit facility, leaving $1.5 billion of unused borrowing capacity. The Company was in compliance with all of its debt covenants. The Company's credit facility contains certain financial covenants, which include the maintenance of a ratio of total debt to book capitalization, subject to certain adjustments, not to exceed .60 to 1.0, which is above the Company's December 31, 2013 ratio of .24 to 1.0. If internal cash flows and cash on hand 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 the Company's credit facility, issuances of debt or equity securities or other sources, such as sales of joint interests or nonstrategic assets. 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 the combination of internal operating cash flows, cash and cash equivalents on hand, proceeds from the divestiture of assets held for sale, proceeds from the sales of other nonstrategic assets and, if necessary, available capacity under the Company's credit facility will be adequate to fund 2014 capital expenditures and dividend payments and 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.

Debt ratings. The Company is rated as investment grade by three credit rating agencies. The Company receives debt credit ratings from several of the major ratings agencies, which are subject to regular reviews. The Company believes that each of the rating agencies considers many factors in determining the Company's ratings, including: production growth opportunities, liquidity, debt levels, asset composition and proved reserve mix. A reduction in the Company's debt ratings could increase the interest rates that the Company incurs on credit facility borrowings and 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, 2013 was $8.9 billion, consisting of $392.6 million of cash and cash equivalents, debt of $2.7 billion and stockholders' equity of $6.6 billion. The Company's debt to book capitalization decreased to 25 percent at December 31, 2013 from 37 percent at December 31, 2012, primarily due to an increase in cash and cash equivalents of $163.3 million and a decrease in long-term debt of $1.1 billion, partially offset by a net loss of $799.5 million during 2013. The Company's ratio of current assets to current liabilities increased to 1.38 to 1.00 at December 31, 2013, as compared to 1.02 to 1.00 at December 31, 2012, primarily due to the reclassification of long-term assets to assets held for sale.

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 at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells. 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, 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 I 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 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, particularly during periods of active exploration. 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 2013, 2012 and 2011, the Company recognized exploration, abandonment, geological and geophysical expense from continuing operations of $98.4 million, $98.3 million and $80.7 million, respectively. During 2013, 2012 and 2011, the Company recognized exploration, abandonment, geological and geophysical expense from discontinued operations of $52.7 million, $108.1 million and $44.9 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, 2013, 2012 and 2011 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, proved 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, 2013 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the 2013 Standardized Measure on a twelve 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," "Item 2. Properties" and Supplementary Information included in "Item 8. Financial Statements and Supplementary Data" 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 commodity 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, Management's Price Outlooks, 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 Notes B and D 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, 2013, the Company carried unproved property costs of $123.4 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, Management's Price Outlooks and 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 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.

(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 project and economics associated with making a determination

on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves to sanction the project or is noncommercial and is impaired. See Note F 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.

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, if any, 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.

Goodwill impairment. The Company reviews its goodwill for impairment at least annually. During the third and fourth quarters of 2013, the Company performed qualitative assessments of goodwill to assess whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether it is necessary to perform the two-step goodwill impairment test. The Company determined that it was not likely that the Company's goodwill was impaired.

For assessments prior to 2012, the Company was required 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 Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding goodwill and assessments of goodwill for impairment.

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. A liability is recorded for these types of contingencies if the Company determines the loss to be both probable and reasonably estimable. 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 commitments and contingencies.

Valuation of stock-based compensation. 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, (c) the closing stock price at the balance sheet date for restricted stock awards that are expected to be settled wholly or partially in cash on their vesting date, (d) the Monte Carlo simulation method for the fair value of performance unit awards and (e) a probability forecasted fair value method for Series B unit awards issued by Sendero. See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's stock-based compensation.

Valuation of other assets and liabilities at fair value. 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 discloses certain financial assets and liabilities at fair value, such as 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 D 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."

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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, 2013, and from which the Company may incur future gains or losses from changes in commodity prices or interest rates.

The fair values of the Company's long-term debt and derivative contracts are determined based on observable inputs and utilizing the Company's valuation models and applications. As of December 31, 2013, the Company was a party to commodity swap contracts, interest rate swap contracts, commodity collar contracts and commodity collar contracts with short put options. See Notes D and E of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the Company's fair value measurements and derivative contracts. The following table reconciles the changes that occurred in the fair values of the Company's open derivative contracts during 2013:

	Derivative Contract Net Assets (Liabilities)		
	Commodities	Interest Rate	Total
	(in thousands)		
Fair value of contracts outstanding as of December 31, 2012	$ 318,377	$ (9,724)	$ 308,653
Changes in contract fair values (a)	(5,793)	9,803	4,010
Contract maturities	(167,164)	—	(167,164)
Contract terminations	(485)	(482)	(967)
Fair value of contracts outstanding as of December 31, 2013	$ 144,935	$ (403)	$ 144,532

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

Quantitative Disclosures

Interest rate sensitivity. See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" and Capital Commitments, Capital Resources and Liquidity included in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for information regarding the Company's outstanding debt and debt transactions.

The following table provides information about financial instruments to which the Company was a party as of December 31, 2013 and that are sensitive to changes in interest rates. The table presents debt 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 aggregate estimated fair value of the Company's outstanding debt. For fixed rate debt, the weighted average interest rates represent the contractual fixed rates that the Company was obligated to periodically pay on the debt as of December 31, 2013. The Company had no outstanding variable rate debt as of December 31, 2013, but presents for the readers' information the average variable contractual rates for its credit facility projected forward proportionate to the forward yield curve for LIBOR on February 20, 2014.

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PIONEER NATURAL RESOURCES COMPANY

INTEREST RATE SENSITIVITY
DEBT OBLIGATIONS AND DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2013

	Year Ending December 31,							Liability Fair Value at December 31, 2013
	2014	2015	2016	2017	2018	Thereafter	Total	
Total Debt:	(in thousands, except percentages)							
Fixed rate principal maturities (a)	$—	$—	$455,385	$485,100	$449,500	$1,300,000	$2,689,985	$ 3,018,830
Weighted average fixed interest rate	6.15%	6.15%	6.17%	6.11%	5.91%	5.81%		
Weighted average variable interest rate	1.77%	2.19%	3.15%	4.17%	—%	—%		
Interest Rate Swaps:								
Notional debt amount	$400,000	$400,000	$400,000	$400,000	$400,000	$354,167		$ 403
Fixed rate payable (%)	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%		
Variable rate receivable (%)	1.39%	1.80%	2.76%	3.79%	4.60%	5.60%		

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

Commodity derivative instruments and price sensitivity. The following table provides information about the Company's oil, NGL and gas derivative financial instruments that were sensitive to changes in commodity prices as of December 31, 2013. Although the cash flow effects are mitigated by the Company's derivative instruments, declines in oil, NGL and gas prices reduce the Company's sales revenues.

The Company manages commodity price risk with derivative contracts, such as swaps, collar contracts and collar contracts with short put options. Swap contracts provide a fixed price for a notional amount of sales volumes. Collar contracts provide minimum ("floor" or "long put") and maximum ("ceiling" or "short call") prices 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 floor-to-short put price differential.

See Notes B, D and E 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.

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PIONEER NATURAL RESOURCES COMPANY

DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2013

	Year Ending December 31,			Asset (Liability) Fair Value at December 31, 2013 (a) (in thousands)
	2014	2015	2016	
Oil Derivatives: (b)				
Average daily notional BBL volumes:				
Swap contracts	10,000	—	—	$ (6,283)
Weighted average fixed price per BBL	$93.87	$—	$—	
Collar contracts with short puts	69,000	85,000	25,000	$ 136,697
Weighted average ceiling price per BBL	$114.05	$98.98	$93.30	
Weighted average floor price per BBL	$93.70	$88.06	$85.00	
Weighted average short put price per BBL	$77.61	$73.06	$70.00	
Average forward NYMEX oil prices (c)	$99.28	$90.13	$84.10	
NGL Derivatives: (d)				
Average daily notional BBL volumes:				
Collar contracts with short puts (e)	1,000	—	—	$ 1,010
Weighted average ceiling price per BBL	$109.50	$—	$—	
Weighted average floor price per BBL	$95.00	$—	$—	
Weighted average short put price per BBL	$80.00	$—	$—	
Average forward NGL prices (f)	$86.99	$—	$—	
Collar contracts (g)	3,000	—	—	$ 270
Weighted average ceiling price per BBL	$13.72	$—	$—	
Weighted average floor price per BBL	$10.78	$—	$—	
Average forward NGL prices (f)	$13.31	$—	$—	
Gas Derivatives:				
Average daily notional MMBTU volumes:				
Swap contracts	195,000	20,000	—	$ (9,105)
Weighted average fixed price per MMBTU	$4.04	$4.31	$—	
Collar contracts with short puts	115,000	285,000	20,000	$ 18,098
Weighted average ceiling price per MMBTU	$4.70	$5.07	$5.36	
Weighted average floor price per MMBTU	$4.00	$4.00	$4.00	
Weighted average short put price per MMBTU	$3.00	$3.00	$3.00	
Average forward NYMEX gas prices (h)	$4.85	$4.22	$4.10	
Basis swap contracts (i)	85,082	30,000	—	$ 4,248
Weighted average fixed price per MMBTU	$(0.20)	$(0.18)	$—	
Average forward basis differential prices (j)	$(0.22)	$(0.32)	$—	

(a) In accordance with Financial Accounting Standards Board Accounting Standards Codification ("ASC") 210-20 and ASC 815-10, 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, as the case may be. The net asset and liability amounts shown above have been provided on a commodity contract-type basis, which may differ from their master netting arrangements classifications.

(b) Subsequent to December 31, 2013, the Company entered into rollfactor swap contracts for 5,000 BBLs per day of the Company's March through December 2014 production with a NYMEX roll price of $0.82 per BBL and 5,000 BBLs per day of the Company's 2015 production with a NYMEX roll price of $0.60 per BBL. Rollfactor swap

contracts fix the difference between (i) each day's price per BBL of WTI for the first nearby month less (ii) the price per BBL of WTI for the second nearby NYMEX month, multiplied by .6667; plus (iii) each day's price per BBL of WTI for the first nearby month less (iv) the price per BBL of WTI for the third nearby NYMEX month, multiplied by .3333.

(c) The average forward NYMEX oil prices are based on February 20, 2014 market quotes.

(d) Subsequent to December 31, 2013, the Company entered into propane swap contracts for 1,000 BBLs per day of March through December 2014 production with a price of $47.57 per BBL and 2,000 BBLs per day of April through October 2014 production with a price of $48.51 per BBL.

(e) Represent collar contracts with short puts that reduce the price volatility of natural gasoline forecasted for sale by the Company at Mont Belvieu, Texas-posted prices.

(f) Forward component NGL prices are derived from respective active-market NGL component price quotes on February 20, 2014.

(g) Represent collar contracts that reduce the price volatility of ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices.

(h) The average forward NYMEX gas prices are based on February 20, 2014 market quotes.

(i) Subsequent to December 31, 2013, the Company entered into additional basis swap contracts for 35,000 MMBTU per day of April through December 2014 production with a negative price differential of $0.27 per MMBTU between the relevant index price and the NYMEX price.

(j) The average forward basis differential prices are based on February 20, 2014 market quotes for basis differentials between the relevant index prices and NYMEX-quoted forward prices.

Marketing and basis transfer derivatives. The Company enters into buy and sell marketing arrangements to fulfill firm pipeline transportation commitments. Associated with these marketing arrangements, the Company may enter into index swaps to mitigate price risk. As of December 31, 2013, the Company had no open marketing derivative positions. Subsequent to December 31, 2013, the Company entered into marketing gas index swap contracts for 20,000 MMBTU per day of March 2014 volumes with a price differential of $0.34 per MMBTU, 10,000 MMBTU per day of April through October 2014 volumes with a price differential of $0.36 per MMBTU and 30,000 MMBTU per day of April through December 2014 volumes with a price differential of $0.30 per MMBTU.

Qualitative Disclosures

The Company's primary market risk exposures are to changes in commodity prices and interest rates. These risks did not change materially from December 31, 2012 to December 31, 2013.

Non-derivative financial instruments. The Company is a borrower under fixed rate debt instruments and, from time to time, under a variable rate debt instrument that gives 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. The Company also enters into oil and gas purchase and sale transactions with third parties to satisfy unused pipeline capacity commitments and to diversify a portion of the Company's WTI oil sales to a Gulf Coast oil price. See Note G 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 and interest rate derivative contracts to mitigate commodity price and interest 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.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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, 2013 and 2012, and the related consolidated statements of operations, comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

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, 2013, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 26, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Dallas, Texas
February 26, 2014

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PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in thousands)

	December 31, 2013	2012
ASSETS		
Current assets:		
Cash and cash equivalents	$392,646	$229,396
Accounts receivable:		
Trade, net	430,732	316,854
Due from affiliates	2,753	3,299
Income taxes receivable	4,784	7,447
Inventories	220,125	197,056
Prepaid expenses	15,852	13,438
Assets held for sale	583,750	—
Other current assets:		
Derivatives	75,237	279,119
Other	2,555	3,746
Total current assets	1,728,434	1,050,355
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	13,406,135	14,259,708
Unproved properties	123,382	231,555
Accumulated depletion, depreciation and amortization	(4,903,122)	(4,412,913)
Total property, plant and equipment	8,626,395	10,078,350
Goodwill	274,329	298,142
Other property and equipment, net	1,224,153	1,217,694
Other assets:		
Investment in unconsolidated affiliate	224,850	204,129
Derivatives	90,854	55,257
Other, net	123,773	165,103
	$12,292,788	$13,069,030

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

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PIONEER NATURAL RESOURCES COMPANY

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

	December 31, 2013	2012
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$910,393	$729,942
Due to affiliates	150,164	96,935
Interest payable	62,374	68,083
Income taxes payable	165	208
Deferred income taxes	19,169	86,481
Liabilities held for sale	38,562	—
Other current liabilities:		
Derivatives	11,626	13,416
Other	57,653	39,725
Total current liabilities	1,250,106	1,034,790
Long-term debt	2,653,059	3,721,193
Derivatives	9,933	12,307
Deferred income taxes	1,472,717	2,140,416
Other liabilities	292,215	293,016
Equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 145,833,707 and 134,966,740 shares issued at December 31, 2013 and 2012, respectively	1,458	1,350
Additional paid-in capital	5,079,821	3,683,934
Treasury stock, at cost: 3,206,054 and 11,611,093 shares at December 31, 2013 and 2012, respectively	(144,776)	(510,570)
Retained earnings	1,665,081	2,514,640
Total equity attributable to common stockholders	6,601,584	5,689,354
Noncontrolling interest in consolidating subsidiaries	13,174	177,954
Total equity	6,614,758	5,867,308
Commitments and contingencies		
	$12,292,788	$13,069,030

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

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PIONEER NATURAL RESOURCES COMPANY

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

	Year Ended December 31,		
	2013	2012	2011
Revenues and other income:			
Oil and gas	$3,155,696	$2,575,311	$2,080,215
Sales of purchased oil and gas	333,822	122,093	14,542
Interest and other	16,961	(1,032)	29,382
Derivative gains, net	4,010	330,251	392,752
Gain (loss) on disposition of assets, net	209,021	45,898	(3,644)
	3,719,510	3,072,521	2,513,247
Costs and expenses:			
Oil and gas production	614,676	558,045	396,961
Production and ad valorem taxes	201,186	178,723	139,425
Depletion, depreciation and amortization	907,077	708,270	489,579
Purchased oil and gas	335,734	120,408	13,949
Impairment of oil and gas properties	1,495,242	—	354,408
Exploration and abandonments	98,448	98,285	80,691
General and administrative	295,868	244,196	189,985
Accretion of discount on asset retirement obligations	11,862	8,677	7,506
Interest	183,750	204,222	181,604
Other	137,386	114,175	63,071
	4,281,229	2,235,001	1,917,179
Income (loss) from continuing operations before income taxes	(561,719)	837,520	596,068
Income tax benefit (provision)	211,775	(290,488)	(188,278)
Income (loss) from continuing operations	(349,944)	547,032	407,790
Income (loss) from discontinued operations, net of tax	(449,605)	(304,210)	474,124
Net income (loss)	(799,549)	242,822	881,914
Net income attributable to noncontrolling interests	(38,865)	(50,537)	(47,425)
Net income (loss) attributable to common stockholders	$(838,414)	$192,285	$834,489
Basic earnings per share attributable to common stockholders:			
Income (loss) from continuing operations	$(2.86)	$4.02	$3.03
Income (loss) from discontinued operations	(3.30)	(2.48)	3.98
Net income (loss)	$(6.16)	$1.54	$7.01
Diluted earnings per share attributable to common stockholders:			
Income (loss) from continuing operations	$(2.86)	$3.91	$2.97
Income (loss) from discontinued operations	(3.30)	(2.41)	3.91
Net income (loss)	$(6.16)	$1.50	$6.88
Weighted average shares outstanding:			
Basic	136,130	122,966	116,904
Diluted	136,130	126,320	119,215
Amounts attributable to common stockholders:			
Income (loss) from continuing operations	$(388,809)	$496,495	$360,365
Income (loss) from discontinued operations, net of tax	(449,605)	(304,210)	474,124
Net income (loss)	$(838,414)	$192,285	$834,489

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

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PIONEER NATURAL RESOURCES COMPANY

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

	Year Ended December 31,		
	2013	2012	2011
Net income (loss)	$(799,549)	$242,822	$881,914
Other comprehensive activity:			
Net hedge (gains) losses included in continuing operations	—	4,855	(32,636)
Income tax (benefit) provision	—	(1,725)	8,407
Other comprehensive activity	—	3,130	(24,229)
Comprehensive income (loss)	(799,549)	245,952	857,685
Comprehensive income attributable to the noncontrolling interests	(38,865)	(50,537)	(33,687)
Comprehensive income (loss) attributable to common stockholders	$(838,414)	$195,415	$823,998

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

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PIONEER NATURAL RESOURCES COMPANY

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

	Equity Attributable to Common Stockholders							
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
Balance as of December 31, 2010	115,309	$1,262	$3,022,768	$(421,235)	$1,510,427	$ 7,361	$ 105,442	$4,226,025
Issuance of common stock	5,500	55	484,105	—	—	—	—	484,160
Sale of Pioneer Southwest common units, net of tax	—	—	26,915	—	—	—	8,176	35,091
Issuance of Pioneer Southwest common units, net of tax	—	—	8,104	—	—	—	40,688	48,792
Dividends declared ($0.08 per share)	—	—	—	—	(9,498)	—	—	(9,498)
Exercise of long-term incentive plan stock options and employee stock purchases	76	—	951	3,097	(352)	—	—	3,696
Purchase of treasury stock	(439)	—	—	(40,157)	—	—	(198)	(40,355)
Conversion of 2.875% convertible senior notes	—	—	(20)	14	—	—	—	(6)
Tax benefits related to stock-based compensation	—	—	31,087	—	—	—	—	31,087
Disposition of subsidiary	—	—	(510)	—	—	—	—	(510)
Compensation costs:								
Vested compensation awards, net	1,410	14	(14)	—	—	—	—	—
Compensation costs included in net income	—	—	40,422	—	—	—	1,251	41,673
Cash distributions to noncontrolling interests	—	—	—	—	—	—	(26,702)	(26,702)
Net income	—	—	—	—	834,489	—	47,425	881,914
Net hedge gains included in	—	—	—	—	—	(10,491)	(13,738)	(24,229)

continuing operations								
Balance as of December 31, 2011	121,856	$1,331	$3,613,808	$(458,281)	$2,335,066	$ (3,130)	$ 162,344	$5,651,138
Dividends declared ($0.08 per share)	—	—	—	—	(9,989)	—	—	(9,989)
Exercise of long-term incentive plan stock options and employee stock purchases	195	—	(849)	10,842	(2,722)	—	—	7,271
Purchase of treasury stock	(542)	—	—	(63,136)	—	—	(189)	(63,325)
Conversion of 2.875% convertible senior notes	—	—	(5)	5	—	—	—	—
Tax benefits related to stock-based compensation	—	—	58,486	—	—	—	—	58,486
Deferred tax provision attributable to 2008 Pioneer Southwest initial public offering	—	—	(49,072)	—	—	—	—	(49,072)
Compensation costs:								
Vested compensation awards, net	1,847	19	(19)	—	—	—	—	—
Compensation costs included in net income	—	—	61,585	—	—	—	1,165	62,750
Cash distributions to noncontrolling interests	—	—	—	—	—	—	(35,903)	(35,903)
Net income	—	—	—	—	192,285	—	50,537	242,822
Net hedge losses included in continuing operations	—	—	—	—	—	3,130	—	3,130
Balance as of December 31, 2012	123,356	$1,350	$3,683,934	$(510,570)	$2,514,640	$ —	$ 177,954	$5,867,308

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

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PIONEER NATURAL RESOURCES COMPANY

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

	Equity Attributable to Common Stockholders						
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Noncontrolling Interests	Total Equity
Balance as of December 31, 2012	123,356	$1,350	$3,683,934	$(510,570)	$2,514,640	$ 177,954	$5,867,308
Issuance of common stock	10,350	103	1,280,813	—		—	1,280,916
Dividends declared ($0.08 per share)	—	—	—	—	(11,145)	—	(11,145)
Exercise of long-term incentive plan stock options and employee stock purchases	222	—	11	10,043	—	—	10,054
Purchase of treasury stock	(154)	—	—	(20,102)	—	—	(20,102)
Conversion of 2.875% senior convertible notes	4,381	—	(197,240)	197,232	—	—	(8)
Tax benefit related to conversion of 2.875% senior convertible notes	—	—	38,415	—		—	38,415
Tax benefits related to stock-based compensation	—	—	17,639	—	—	—	17,639
Pioneer Southwest merger:							
Issuance of treasury stock to acquire outstanding PSE units	3,956	—	(178,621)	178,621		—	—
Pioneer Southwest merger transaction costs	—	—	(3,880)	—		—	(3,880)
Pioneer Southwest noncontrolling interest transferred to APIC	—	—	168,685	—		(168,685)	—
Deferred tax benefit associated with the Pioneer Southwest merger	—	—	200,091	—	—	—	200,091
Compensation costs:							
Vested compensation awards, net	517	5	(5)	—	—	—	—
Compensation costs included in net income	—	—	69,979	—	—	1,094	71,073
Cash distributions to noncontrolling interests	—	—	—	—	—	(36,054)	(36,054)
Net income (loss)	—	—	—	—	(838,414)	38,865	(799,549)
Balance as of December 31, 2013	142,628	$1,458	$5,079,821	$(144,776)	$1,665,081	$ 13,174	$6,614,758

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

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PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Year Ended December 31,		
	2013	2012	2011
Cash flows from operating activities:			
Net income (loss)	$(799,549)	$242,822	$881,914
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	907,077	708,270	489,579
Impairment of oil and gas properties	1,495,242	—	354,408
Impairment of inventory and other property and equipment	61,812	5,719	3,126
Exploration expenses, including dry holes	21,379	31,189	32,529
Deferred income taxes	(222,374)	286,229	181,330
(Gain) loss on disposition of assets, net	(209,021)	(45,898)	3,644
Accretion of discount on asset retirement obligations	11,862	8,677	7,506
Discontinued operations	612,880	497,579	(265,327)
Interest expense	17,225	35,563	31,483
Derivative related activity	164,121	68,604	(221,899)
Amortization of stock-based compensation	70,999	62,567	41,442
Amortization of deferred revenue	—	(42,069)	(44,951)
Other noncash items	(6,073)	(45,293)	3,599
Change in operating assets and liabilities			
Accounts receivable, net	(122,914)	(28,206)	(47,331)
Income taxes receivable	2,663	(5,953)	29,406
Inventories	(39,062)	33,059	(137,401)
Prepaid expenses	(531)	1,447	(3,415)
Other current assets	3,964	14,291	1,957
Accounts payable	208,692	46,038	136,296
Interest payable	(5,709)	10,842	(1,768)
Income taxes payable	(62)	(9,580)	(7,623)
Other current liabilities	(27,342)	(38,320)	61,210
Net cash provided by operating activities	2,145,279	1,837,577	1,529,714
Cash flows from investing activities:			
Proceeds from disposition of assets, net of cash sold	711,027	95,564	819,044
Payments for acquisition, net of cash acquired	—	(297,092)	—
Distribution from (investment in) unconsolidated subsidiary	25,050	—	(89,620)
Additions to oil and gas properties	(2,638,799)	(2,758,073)	(1,926,965)
Additions to other assets and other property and equipment, net	(237,082)	(296,809)	(363,246)
Net cash used in investing activities	(2,139,804)	(3,256,410)	(1,560,787)
Cash flows from financing activities:			
Borrowings under long-term debt	466,864	1,776,618	196,616
Principal payments on long-term debt	(1,546,771)	(612,001)	(294,883)
Proceeds from issuance of common stock, net of issuance costs	1,280,916	—	484,160
Proceeds from issuance of partnership common units, net of issuance costs	—	—	122,976
Distributions to noncontrolling interests	(36,054)	(35,903)	(26,702)
Payments of other liabilities	(3,625)	(1,153)	(901)
Exercise of long-term incentive plan stock options and employee stock purchases	10,054	7,271	3,696

Purchase of treasury stock	(20,102)	(63,325)	(40,355)
Excess tax benefits from share-based payment arrangements	17,639	58,486	31,087
Payment of financing fees	(8)	(9,227)	(8,741)
Dividends paid	(11,138)	(10,021)	(9,556)
Net cash provided by financing activities	157,775	1,110,745	457,397
Net increase (decrease) in cash and cash equivalents	163,250	(308,088)	426,324
Cash and cash equivalents, beginning of period	229,396	537,484	111,160
Cash and cash equivalents, end of period	$392,646	$229,396	$537,484

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

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PIONEER NATURAL RESOURCES COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2013, 2012 and 2011

NOTE A. Organization and Nature of Operations

Pioneer Natural Resources Company ("Pioneer" or "the Company") is a Delaware corporation whose common stock is listed and traded on the New York Stock Exchange. The Company is a large independent oil and gas exploration and production company in the United States, with continuing field operations in the Permian Basin in West Texas, the Eagle Ford Shale play in South Texas, the Raton field in southeastern Colorado, the Hugoton field in southwest Kansas and the West Panhandle field in the Texas Panhandle. The Company's objective is to maximize shareholder investment returns by maintaining financial flexibility, capital allocation discipline and enhancing net asset value through accretive drilling programs, joint ventures and acquisitions.

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. In accordance with generally accepted accounting principles in the United States ("GAAP"), the Company proportionately consolidates certain affiliate partnerships that are less than wholly-owned and are involved in oil and gas producing activities. All material intercompany balances and transactions have been eliminated.

Certain reclassifications have been made to the 2012 and 2011 financial statement and footnote amounts in order to conform them to the 2013 presentations.

In addition, the presentation of purchases and sales of third-party oil and gas has been revised in 2012 and 2011 to present separately the gross sales of purchased oil and gas and costs of purchased oil and gas. Previously, the sales and purchases were netted in other expense. Revenues and costs from the purchase and sale transactions are presented on a gross basis as the Company acts as a principal in the transactions by assuming the risks and rewards of ownership, including credit risk, of the oil and gas purchased and assumes responsibility to deliver the oil and gas volumes sold. This revision did not impact the Company's balance sheet, net income (loss) from continuing operations, equity or cash flows. While not material to the 2012 and 2011 financial statements as a whole, the presentation has been revised to enhance consistency. The following individual line items were affected in addition to total revenues and other income, and total costs and expenses:

	Year Ended December 31,	
	2012	2011
	(in thousands)	
Sales of purchased oil and gas, as previously reported	$—	$—
Revision of sales of purchased oil and gas	122,093	14,542
Sales of purchased oil and gas, reported herein	$122,093	$14,542
Purchased oil and gas, as previously reported	$—	$—
Revision of purchased oil and gas	120,408	13,949
Purchased oil and gas, reported herein	$120,408	$13,949
Other expense, as previously reported (excluding amounts included in discontinued operations)	$112,490	$62,478
Revision of other expense	1,685	593
Other expense, reported herein	$114,175	$63,071

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, probable and possible oil and gas reserves. There are numerous uncertainties inherent in the

estimation of quantities of proved, probable and possible 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 and commodity price outlooks. Actual results could differ from the estimates and assumptions utilized.

Cash and cash equivalents. The Company's cash and cash equivalents include depository accounts held by banks and marketable securities with original issuance maturities of 90 days or less.

Accounts receivable. As of December 31, 2013 and 2012, the Company had accounts receivable – trade, net of allowances for bad debts, of $430.7 million and $316.9 million, respectively. The Company's accounts receivable – trade are primarily comprised of oil and gas sales receivables, joint interest receivables and other receivables for which the Company does not require collateral security.

As of December 31, 2013 and 2012, the Company's allowances for doubtful accounts totaled $1.4 million and $1.5 million, respectively. The Company establishes allowances for bad debts equal to the estimable portions of accounts receivable 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.

Inventories. The Company's inventories consist of materials, supplies and commodities. The Company's materials and supplies inventory is primarily comprised of oil and gas drilling or repair items such as tubing, casing, proppant used to fracture-stimulate oil and gas wells, 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. 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 charges to other expense in the accompanying consolidated statements of operations.

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 held in storage and natural gas liquids ("NGLs") and gas pipeline fill volumes. 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.

The following table presents the Company's materials and supplies and commodities inventories as of December 31, 2013 and 2012:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Materials and supplies (a)	$210,792	$258,962
Commodities	13,429	5,446
Less: Noncurrent materials and supplies (b)	(4,096)	(67,352)
	$220,125	$197,056

(a) As of December 31, 2013 and 2012, the Company's materials and supplies inventories were net of valuation reserve allowances of $31.8 million and $4.6 million, respectively. See Note D for additional information regarding inventory impairments.

(b) Included in other noncurrent assets in the Company's accompanying consolidated balance sheet.

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.
(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 project 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 data in the area, 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 sufficient proved reserves to sanction the project or is noncommercial and is charged to exploration and abandonments expense. See Note F for additional information regarding the Company's suspended exploratory well costs.

The Company owns interests in six gas processing plants and nine treating facilities. The Company is the operator of two of the gas processing plants and all nine of the treating facilities. The Company's ownership interests in the gas processing plants and treating facilities are 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 processing plants and treating facilities in continuing operations for the three years ended December 31, 2013, 2012 and 2011 were $57.2 million, $34.4 million and $42.6 million, respectively. Third party expenses attributable to the processing plants and treating facilities in continuing operations for the same respective periods were $30.1 million, $26.5 million and $22.6 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.

The capitalized costs of 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 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, if doing so does not materially impact the depletion rate of an amortization base. Generally, no gain or loss is recognized until an 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 amortization base.

The Company performs assessments of 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 these circumstances, 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. See Note D for additional information regarding the Company's impairment of proved oil and gas properties.

Unproved oil and gas properties are periodically assessed for impairment on a project-by-project basis. These impairment assessments are affected by the results of exploration activities, commodity price outlooks, planned future

sales or expirations of all or a portion of such projects. If the estimated future net cash flows attributable to such projects are not expected to be sufficient to fully recover the costs invested in each project, the Company will recognize an impairment loss at that time.

Goodwill. During 2004, the Company recorded goodwill associated with a business combination, which represents the cost of an acquired entity over the net amounts assigned to assets acquired and liabilities assumed. 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 earnings in the period in which it is determined to be impaired. During the third quarter of 2013, the Company performed a qualitative assessment of goodwill to determine whether it was more likely than not that the fair value of the Company's reporting unit was less than its carrying amount as a basis for determining

whether it was necessary to perform the two-step goodwill impairment test. Based upon the results of the assessment, the Company determined that it was not likely that the Company's goodwill was impaired.

For the year ended December 31, 2013, the Company reduced the carrying value of goodwill by $23.8 million, reflecting the portion of the Company's goodwill related to assets sold or included in assets held for sale at December 31, 2013, primarily associated with the sale of 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas, and the planned sales of the Company's Alaska subsidiary and Barnett Shale net assets. See Note C for additional information regarding the Company's divestitures. At December 31, 2013, the Company performed a qualitative assessment of its remaining goodwill to determine whether it is more likely than not that the fair value of the Company's reporting unit is less than its carrying amount, and the Company determined that it is not likely that the Company's remaining goodwill is impaired.

Other property and equipment, net. Other property and equipment is recorded at cost. At December 31, 2013 and 2012, respectively, the net carrying value of other property and equipment consisted of the following:

	Year Ended December 31,	
	2013 (a)	2012 (a)
	(in thousands)	
Proved and unproved sand properties (b)	$451,384	$457,033
Equipment and rigs (c)	313,165	385,887
Land and buildings	344,554	259,629
Transportation equipment	41,397	44,928
Furniture and fixtures	47,905	43,614
Leasehold improvements	25,748	26,603
	$1,224,153	$1,217,694

(a) At December 31, 2013 and 2012, other property and equipment was net of accumulated depreciation of $458.4 million and $395.9 million, respectively.

(b) Includes sand mines, sales facilities and unproved leaseholds that primarily provide the Company and other unrelated customers with proppant used in the fracture stimulation of oil and gas wells.

(c) Includes drilling rigs, well servicing rigs and equipment and fracture stimulation equipment including assets owned by subsidiaries that provide drilling, pumping and well services on Company-operated properties. As of December 31, 2013, the Company owned 15 drilling rigs, eleven fracture stimulation fleets and other oilfield services equipment, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. During December 2013, the Company committed to a plan to sell its majority interest in Sendero Drilling Company, LLC ("Sendero"), which owns the Company's 15 vertical drilling rigs, to Sendero's minority interest owner. Associated therewith, the Company has classified the assets and liabilities of Sendero, including $17.9 million of drilling rigs, as assets held for sale in the accompanying consolidated balance sheet as of December 31, 2013. See Note C for additional information.

The primary purposes of the Company's sand mines and drilling, pumping and well services operations are to accommodate the Company's drilling and producing operations by increasing the availability of supplies, equipment and services, rather than being dependent on third-party availability, and to contain associated costs. All intercompany gains or losses of the Company's sand mines and drilling, pumping and well services operations are eliminated. Earnings from sales of proppant and from providing drilling, pumping and well services to third-party customers and working interest owners in Company-operated properties are included in interest and other income in the accompanying consolidated statements of operations.

The capitalized costs of proved sand properties are depleted using the unit-of-production method based on proved sand reserves. Equipment items are generally depreciated by individual component on a straight line basis over their economic useful lives, which are generally from two to 12 years. Leasehold improvements are amortized over the lesser of their economic useful lives or the underlying terms of the associated leases.

The Company evaluates other property and equipment for potential impairment whenever indicators of impairment are present. Circumstances that could indicate potential impairment include: significant adverse changes in industry trends and the economic outlook; legal actions; regulatory changes; and significant declines in utilization rates or oil and gas prices. If it is determined that other property and equipment is potentially impaired, the Company performs an impairment evaluation by estimating the future undiscounted net cash flow from the use and eventual disposition of other property and equipment grouped at the lowest level that cash flows can be identified. If the sum of the future undiscounted net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the assets' net book value over its estimated fair value.

Investment in unconsolidated affiliate. During 2010, the Company formed EFS Midstream LLC ("EFS Midstream") to own and operate gas and liquids gathering, treating and transportation assets in the Eagle Ford Shale play in South Texas. During June 2010, the Company sold a 49.9 percent member interest in EFS Midstream to an unaffiliated third party for $46.4 million of cash proceeds. Associated therewith, the Company recorded a $46.2 million deferred gain that is being amortized as a reduction in production costs over a 20 year period, representing the term of a continuing commitment of Pioneer to deliver production volumes through EFS Midstream handling and gathering facilities. The deferred gain is included in other current and noncurrent liabilities in the Company's accompanying consolidated balance sheet.

The Company does not have control of EFS Midstream. Consequently, the Company accounts for this investment under the equity method of accounting for investments in unconsolidated affiliates. Under the equity method, the Company's investment in unconsolidated affiliates is increased for investments made and the investor's share of the investee's net income, and decreased for distributions received, the carrying value of member interests sold and the investor's share of the investee's net losses.

The Company's equity interest in the net income or loss of EFS Midstream is recorded in interest and other income, net of eliminations of the profit associated with gathering, treating and transportation fees charged to the Company by EFS Midstream, in the accompanying consolidated statements of operations. See Note M for the Company's equity interest in the net income of EFS Midstream for the years ended December 31, 2013, 2012 and 2011.

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 to which it relates. Conditional asset retirement obligations meet the definition of liabilities and are recognized when incurred if their fair values can be reasonably estimated.

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 and expenditures are classified as cash used in operating activities in the accompanying consolidated statements of cash flows. See Note I for additional information about the Company's asset retirement obligations.

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.

Issuance of common stock. In February 2013, the Company issued 10.35 million shares of its common stock and realized $1.3 billion of cash proceeds, net of associated underwriting and offering expenses.

Noncontrolling interest in consolidated subsidiaries. The Company owns the majority interests in certain subsidiaries with operations in the United States. Prior to December 17, 2013, the Company owned a 0.1 percent general partner interest and a 52.4 percent limited partner interest in Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest") and consolidated the financial position, results of operations and cash flows of Pioneer Southwest with those of Pioneer. Pioneer Southwest owned proved and unproved oil and gas properties in the Spraberry field in the Permian Basin of West Texas. On December 17, 2013, the holders of a majority of the outstanding common units of Pioneer Southwest approved an amended agreement and plan of merger, pursuant to which (i) all of the then outstanding

common units of Pioneer Southwest were canceled and converted into the right to receive 0.2325 of a share of common stock of the Company and (ii) Pioneer Southwest became a wholly-owned subsidiary of the Company. The changes in the Company's ownership of Pioneer Southwest were accounted for by eliminating the noncontrolling interest attributable to Pioneer Southwest. See Note C for additional information about Pioneer Southwest and the amended agreement and plan of merger.

Noncontrolling interests in the net assets of consolidated subsidiaries totaled $13.2 million and $178.0 million as of December 31, 2013 and 2012, respectively. The Company recorded net income attributable to the noncontrolling interests of $38.9 million, $50.5 million and $47.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

In accordance with GAAP, the Company records transfers of any gains or losses, net of taxes, from noncontrolling interests in consolidated subsidiaries to additional paid in capital proportionate to the ownership after giving effect to the purchase or sale of common units. The following table presents the Company's net income or loss attributable to common stockholders adjusted for changes in equity as a result of transactions that changed the Company's ownership interest in Pioneer Southwest:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Net income (loss) attributable to common stockholders	$(838,414)	$192,285	$834,489
Transfers from the noncontrolling interest in consolidated subsidiaries:			
Increase in additional paid in capital from the sale of 1.8 million Pioneer Southwest common units during 2011, net of tax of $15.4 million	—	—	26,915
Increase in additional paid in capital from Pioneer Southwest's offering of 2.6 million common units during 2011, net of tax of $23.7 million	—	—	8,104
Decrease in additional paid in capital for deferred taxes recognized attributable to Pioneer Southwest's 2008 initial public offering of 9.5 million common units	—	(49,072)	—
Increase in additional paid in capital from Pioneer Southwest merger	168,685	—	—
Increase in additional paid in capital from deferred taxes recognized attributable to Pioneer Southwest merger	200,091	—	—
Decrease in additional paid in capital from Pioneer Southwest merger transaction costs	(3,880)	—	—
Net increase (decrease) in equity from transactions with noncontrolling interests	364,896	(49,072)	35,019
Net income (loss) attributable to common stockholders and changes in equity from transactions with noncontrolling interests	$(473,518)	$143,213	$869,508

Revenue recognition. The Company recognizes revenue when it is 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) collectability is reasonably assured.

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

The Company had no material oil or NGL entitlement assets or liabilities as of December 31, 2013 or 2012. The following table presents the Company's gas entitlement assets and liabilities with their associated volumes as of December 31, 2013 and 2012. Gas volumes are presented in millions of cubic feet ("MMCF").

	December 31,			
	2013		2012	
	Amount	Volume	Amount	Volume
	(dollars in millions)			
Gas entitlement assets	$7.4	2,990	$6.8	2,870
Gas entitlement liabilities	$2.5	715	$1.9	582

The Company enters into oil and gas purchase transactions with third parties and separate sale transactions with third parties to satisfy unused pipeline capacity commitments and to diversify a portion of the Company's WTI oil sales to a Gulf Coast oil price. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming the risk and rewards of ownership, including credit risk, of the oil and gas purchased and assuming responsibility to deliver the oil and gas volumes sold. Deficiency payments on excess pipeline capacity are included in other expense in the accompanying consolidated statements of operations. See Note N for further information on transportation commitment charges.

The Company recognized revenue of $42.1 million and $45.0 million during 2012 and 2011, respectively from volumetric production payment ("VPP") agreements which represented limited-term overriding royalty interests in oil reserves that: (i) entitled the purchaser to receive production volumes over a period of time from specific lease interests, (ii) were free and clear of all associated production costs and capital expenditures associated with the reserves, (iii) were nonrecourse to the Company (i.e., the purchaser's only recourse was to the reserves acquired), (iv) transferred title of the reserves to the purchaser and (v) allowed the Company to retain the remaining reserves after the VPPs volumetric quantities had been delivered. The Company had no VPP obligations in 2013 as all VPP production volumes were delivered as of December 31, 2012; as such, the Company recognized no VPP revenue in 2013.

Derivatives. All derivatives are recorded in the accompanying consolidated balance sheets at estimated fair value. Effective February 1, 2009, the Company discontinued hedge accounting on all of its then-existing hedge contracts. The effective portions of the discontinued deferred hedges as of February 1, 2009 were included in accumulated other comprehensive income (loss) ("AOCI - Hedging") and were transferred to earnings during the same periods in which the forecasted hedged transactions were recognized in the Company's earnings. During 2012, the remaining AOCI - Hedging losses were transferred to earnings. Since discontinuing hedge accounting, the Company has recognized all 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 current or noncurrent derivative assets or net current or noncurrent derivative liabilities, whichever the case may be, by commodity and 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 and, through the date of the merger, Pioneer Southwest's credit-adjusted risk-free rate curves. The credit-adjusted risk-free rate curves for the Company and the counterparties are based on their independent market-quoted credit default swap rate curves plus the United States Treasury Bill yield curve as of the valuation date. Pioneer Southwest's credit-adjusted risk-free rate curve was based on independent market-quoted forward London Interbank Offered Rate ("LIBOR") curves plus 162.5 basis points, representing Pioneer Southwest's estimated borrowing rate. See Note E for additional information about the Company's derivative instruments.

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 for expenditures that will not qualify for capitalization 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. Environmental liabilities normally involve estimates that are subject to revision until settlement occurs.

Stock-based compensation. For stock-based compensation awards granted or modified, stock-based compensation expense is being recognized in the Company's financial statements on a straight line basis over the awards' vesting periods based on their fair values on the dates of grant or modification, as applicable. The stock-based compensation awards generally vest over a period not exceeding three years. The amount of stock-based compensation expense recognized at any date is approximately equal to the ratable portion of the grant date value of the award that is vested at that date. 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, restricted stock units, partnership unit awards or phantom unit awards that are expected to be settled in the Company's common stock ("Equity Awards"), (iii) the Monte Carlo simulation method for the fair value of performance unit awards and (iv) a probabilistic forecasted fair value method for Series B unit awards issued by Sendero.

Stock-based compensation liability awards are awards that are expected to be settled in cash on their vesting dates, rather than in equity shares or units ("Liability Awards"). Stock-based Liability Awards are recorded as accounts payable—affiliates based on the vested portion of the fair value of the awards on the balance sheet date. The fair values of Liability Awards are updated at each balance sheet date and changes in the fair values of the vested portions of the awards are recorded as increases or decreases to stock-based compensation expense.

Segments. Operating segments are defined as components of an enterprise that (i) engage in activities from which it may earn revenues and incur expenses (ii) for which separate operational financial information is available and is regularly evaluated by the chief operating decision maker for the purpose of allocating resources and assessing performance.

Based upon how the Company is organized and managed, the Company has only one reportable operating segment, which is oil and gas exploration and production. The Company considers its vertical integration services as ancillary to its oil and gas

exploration and producing activities and manages these services to support such activities. In addition, the Company has a single, company-wide management team that allocates capital resources to maximize profitability and measures financial performance as a single enterprise.

Assets held for sale and discontinued operations. On the date at which the Company meets all the held for sale criteria, the Company discontinues the recording of depletion and depreciation of the assets or asset group to be sold and reclassifies the assets and related liabilities to be sold as held for sale on the accompanying consolidated balance sheets. The assets and liabilities are measured at the lower of their carrying amount or estimated fair value less cost to sell.

In addition, after determining that held for sale criteria has been met, the Company considers whether the held for sale assets meet the criteria to be considered discontinued operations. If the assets held for sale are considered discontinued operations, the Company classifies the results of operations from the assets held for sale as income or loss from discontinued operations, net of tax in the accompanying consolidated statements of operations for the current period and all prior periods. See Note C for additional information about the Company's divestitures.

New accounting pronouncements. In July 2013, the Financial Accounting Standards Boards issued Accounting Standards Update ("ASU") 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists," which provides guidance on the presentation of unrecognized tax benefits. The adoption of ASU 2013-11 during the third quarter of 2013 did not have a material impact on the Company's financial position and had no impact on the Company's statements of operations or cash flows.

NOTE C. Acquisitions and Divestitures

Pioneer Southwest Merger Transaction

On December 17, 2013, the Company completed the acquisition of all of the outstanding common units of Pioneer Southwest not already owned by the Company, through a merger of a wholly-owned subsidiary of the Company into Pioneer Southwest, the result of which was that Pioneer Southwest became a wholly-owned subsidiary of the Company. The merger was effected pursuant to an Agreement and Plan of Merger dated August 9, 2013, as amended on October 25, 2013 (as amended, the "Merger Agreement"), and was approved by the holders of the common units of Pioneer Southwest at a special meeting held on December 17, 2013.

Pursuant to the Merger Agreement, all of the common units outstanding as of the closing of the merger except for the common units owned by the Company, were canceled and converted into the right to receive 0.2325 of a share of common stock of the Company per common unit (the "Conversion Ratio"). In lieu of receiving any fractional share of common stock to which any holder of the Pioneer Southwest's common units would otherwise have been entitled, after aggregating all fractions of shares to which such holder would be entitled, any fractional share was rounded up to a whole share of common stock of the Company. Consequently, in December 2013, the Company issued an aggregate of 3.96 million shares of its common stock to Pioneer Southwest unitholders. The merger is expected to facilitate the Company's plans to fully and optimally develop the Company's properties in the Midland Basin in West Texas utilizing horizontal drilling and is expected to enhance the Company's organizational, operational and administrative efficiencies.

On December 18, 2013, the Company caused Pioneer Southwest, its general partner and all of Pioneer Southwest's subsidiaries to be merged with and into a wholly-owned subsidiary of the Company, the result of which was that all common units of Pioneer Southwest were canceled and the Company no longer holds any common units.

Premier Silica Business Combination

On April 2, 2012, a wholly-owned subsidiary of the Company acquired an industrial sand mining business that is now named Premier Silica LLC ("Premier Silica"). Premier Silica's primary mine operations are in Brady, Texas. The Brady mine facilities primarily produce, process and provide sand to the Company for use as proppant in its fracture stimulation of oil and gas wells in Texas. Premier Silica's sand production that is in excess of the Company's sand

needs for fracture stimulation and sand production that is not usable for fracture stimulation is primarily sold to third parties for industrial and recreational purposes. The aggregate purchase price of Premier Silica was $297.1 million, including closing adjustments.

Divestitures Recorded in Continuing Operations

During December 2013, the Company committed to a plan to sell the Company's majority interest in Sendero to Sendero's minority interest owner for $31.0 million, subject to negotiating a definitive sales agreement and the buyer completing its financing arrangements. Associated with the planned sale of Sendero, the Company recorded a noncash loss of $25.5 million in other expense during December 2013 to reduce the carrying value of Sendero's net assets to their estimated fair value. As part of the sales negotiations, the Company plans to commit to lease 12 Sendero rigs through December 31, 2015, and to lease eight Sendero rigs in 2016. The Company has classified Sendero assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013.

The Company recorded net gains on disposition of assets in continuing operations of $209.0 million and $45.9 million during the years ended December 31, 2013 and 2012, respectively, and a net loss on disposition of assets in continuing operations of $3.6 million during the year ended December 31, 2011. The following describes the significant divestitures included in continuing operations:

- Southern Wolfcamp. In January 2013, the Company signed an agreement with Sinochem Petroleum USA LLC ("Sinochem"), a U.S. subsidiary of the Sinochem Group, an unaffiliated third party, to sell 40 percent of Pioneer's interest in 207,000 net acres leased by the Company in the horizontal Wolfcamp Shale play in the southern portion of the Spraberry field in West Texas for total consideration of $1.8 billion, including normal closing adjustments. In May 2013, the Company completed the sale to Sinochem for net cash proceeds of $623.8 million, including normal closing adjustments, resulting in a gain of $181.3 million related to the unproved property interests conveyed to Sinochem. Sinochem is paying the remaining $1.2 billion of the transaction price by carrying 75 percent of Pioneer's portion of ongoing drilling and facilities costs attributable to the Company's joint operations with Sinochem in the horizontal Wolfcamp Shale play.
- West Panhandle. During the first quarter of 2013, the Company completed a sale of its interest in unproved oil and gas properties adjacent to the Company's West Panhandle field operations for net cash proceeds of $38.1 million, which resulted in a gain of $22.4 million,
- Eagle Ford Shale. In January 2012, the Company sold a portion of its interest in an unproved oil and gas property in the Eagle Ford Shale play to unaffiliated third parties for cash proceeds of $54.7 million, which resulted in a gain of $42.6 million.
- Other. During 2013, 2012 and 2011, the Company sold other proved and unproved properties, inventory and other property and equipment and recorded net gains of $5.3 million and $3.3 million during 2013 and 2012, respectively, and a net loss of $3.6 million during 2011.

Discontinued Operations

Alaska. During the fourth quarter of 2013, the Company committed to a plan to sell 100 percent of the capital stock in Pioneer's Alaska subsidiary, representing all the Company's net assets in Alaska ("Pioneer Alaska"). The sale of Pioneer Alaska continues to be subject to ongoing negotiations and certain other conditions, such as governmental approvals and buyer's arrangement of financing.

The Company has classified (i) Pioneer Alaska assets and liabilities as held for sale in the accompanying consolidated balance sheet as of December 31, 2013 and (ii) Pioneer Alaska results of operations as income (loss) from discontinued operations, net of tax in the accompanying consolidated statements of operations (including a recasting of the Pioneer Alaska results of operations for the years ended December 31, 2012 and 2011, which were originally classified as continuing operations).

Associated with the planned sale of Pioneer Alaska, the Company recorded a noncash impairment charge of $539.8 million in discontinued operations during December 2013 to reduce the carrying value of Pioneer Alaska to its estimated fair value less costs to sell of $350.6 million. See Note D for additional information about the Pioneer Alaska impairment charge. The recasting of Pioneer Alaska results includes the sale of the Company's interest in the Cosmopolitan Unit in the Cook Inlet of Alaska in August 2012 to unaffiliated third parties for cash proceeds of $10.1

million, which, together with certain Company obligations assumed by the purchasers, resulted in a gain of $12.6 million.

Barnett Shale. During the fourth quarter of 2013, the Company committed to a plan to divest of its net assets in the Barnett Shale field in North Texas. The plan is expected to result in the sale of the Barnett Shale net assets during 2014. The Company has classified its (i) Barnett Shale assets and liabilities as held for sale in the accompanying consolidated balance sheet as of

December 31, 2013 and (ii) Barnett Shale results of operations as income (loss) from discontinued operations, net of tax in the accompanying consolidated statements of operations (including a recasting of the Barnett Shale results of operations for the years ended December 31, 2012 and 2011, which were originally classified as continuing operations).

Associated with the Company's plan to sell its net assets in the Barnett Shale field, the Company recorded a noncash impairment charge of $189.5 million in discontinued operations in December 2013 to reduce the carrying value of its net assets in the Barnett Shale field to their estimated fair value less costs to sell. See Note D for more information about the impairment of Barnett Shale net assets. Also included in discontinued operations in 2013 is the sale of the Company's interest in certain proved and unproved oil and gas properties in the Barnett Shale field for net cash proceeds of $33.8 million, which resulted in a gain of $8.7 million on the unproved properties sold.

The Company's plans to sell Pioneer Alaska and the Barnett Shale net assets are in differing stages of marketing and negotiation. No assurance can be given that the sales will be completed in accordance with the Company's plans.

South Africa. In December 2011, the Company committed to a plan to exit South Africa and initiated a process to divest its net assets in South Africa ("Pioneer South Africa"). During the first quarter of 2012, the Company agreed to sell its net assets in Pioneer South Africa to an unaffiliated third party, effective January 1, 2012, for $60.0 million of cash proceeds before normal closing and other adjustments, and the buyer's assumption of certain liabilities of the Company's South Africa subsidiaries. In August 2012, the Company completed the sale of Pioneer South Africa for net cash proceeds of $15.9 million, including normal closing adjustments for cash revenues and costs and expenses from the effective date through the date of the sale, resulting in a gain of $28.6 million. The Company classified Pioneer South Africa's results of operations as income from discontinued operations, net of tax in the accompanying consolidated statements of operations.

Tunisia. In February 2011, the Company sold 100 percent of the Company's share holdings in Pioneer Natural Resources Tunisia Ltd. and Pioneer Natural Resources Anaguid Ltd. (referred to in the aggregate as "Pioneer Tunisia") to an unaffiliated third party for cash proceeds of $802.5 million, including normal closing adjustments and excluding cash and cash equivalents sold, resulting in a gain of $645.2 million. Accordingly, the Company has classified the results of operations of Pioneer Tunisia as discontinued operations, net of tax in the accompanying consolidated statements of operations.

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The following table represents the components of the Company's discontinued operations for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
	(in thousands)		
Revenues and other income:			
Oil and gas	$260,503	$285,542	$314,124
Interest and other (a)	38,642	29,437	45,145
Gain on disposition of assets, net (b)	8,764	40,735	645,241
	307,909	355,714	1,004,510
Costs and expenses:			
Oil and gas production	90,333	79,853	55,698
Production and ad valorem taxes	10,151	9,034	8,239
Depletion, depreciation and amortization (b)	103,787	101,921	130,606
Impairment of oil and gas properties (b) (c)	729,305	532,589	—
Exploration and abandonments	52,707	108,076	44,898
General and administrative	12,261	6,061	13,517
Accretion of discount on asset retirement obligations (b)	831	2,731	3,436
Interest	—	—	829
Other	9,021	2,096	5,849
	1,008,396	842,361	263,072
Income (loss) from discontinued operations before income taxes	(700,487)	(486,647)	741,438
Current tax provision	(5,591)	(10,387)	(46,012)
Deferred tax (provision) benefit (b)	256,473	192,824	(221,302)
Income (loss) from discontinued operations	$(449,605)	$(304,210)	$474,124

(a) Primarily comprised of Alaskan Petroleum Production Tax credits on qualifying capital expenditures of $38.6 million, $29.3 million and $38.9 million for the years ended December 31, 2013, 2012 and 2011, respectively.

(b) Represents significant noncash components of discontinued operations.

(c) Represents a noncash impairment charge of $539.8 million on Pioneer Alaska net assets during the year ended December 31, 2013 and noncash impairment charges of $189.5 million and $532.6 million during the years ended December 31, 2013 and 2012, respectively, on the Company's net assets in the Barnett Shale field. See Note D for additional information regarding the noncash impairment charges.

As of December 31, 2013, the carrying values of the Company's ownership in Pioneer Alaska, the Barnett Shale field and Sendero were included in assets and liabilities held for sale in the accompanying consolidated balance sheet and were comprised of the following (the Company had no assets held for sale as of December 31, 2012):

	December 31, 2013
	(in thousands)
Composition of assets included in assets held for sale:	
Current assets (excluding cash and cash equivalents)	$57,602
Property, plant and equipment	526,148
Total assets	$583,750
Composition of liabilities included in liabilities held for sale:	

Current liabilities	$28,771
Other liabilities	9,791
Total liabilities	$38,562

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NOTE D. Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are based upon inputs that market participants use in pricing an asset or liability, which are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. 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. The three input levels of the fair value hierarchy are as follows:

- 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.

Assets and liabilities measured at fair value on a recurring basis. 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, 2013 and 2012 for each of the fair value hierarchy levels:

	Fair Value Measurements at the End of the Reporting Period 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, 2013
	(in thousands)			
Assets:				
Trading securities	$136	$146	$—	$282
Commodity derivatives	—	156,561	—	156,561
Interest rate derivatives	—	9,530	—	9,530
Deferred compensation plan assets	63,971	—	—	63,971
Total assets	64,107	166,237	—	230,344
Liabilities:				
Commodity derivatives	—	11,626	—	11,626
Interest rate derivatives	—	9,933	—	9,933
Total liabilities	—	21,559	—	21,559
Total recurring fair value measurements	$64,107	$144,678	$—	$208,785

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	Fair Value Measurements at the End of the Reporting Period Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1) (in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Fair Value at December 31, 2012
Assets:				
Trading securities	$124	$154	$—	$278
Commodity derivatives	—	334,376	—	334,376
Deferred compensation plan assets	49,685	—	—	49,685
Total assets	49,809	334,530	—	384,339
Liabilities:				
Commodity derivatives	—	15,999	—	15,999
Interest rate derivatives	—	9,724	—	9,724
Total liabilities	—	25,723	—	25,723
Total recurring fair value measurements	$49,809	$308,807	$—	$358,616

Trading securities and deferred compensation plan assets. The Company's trading securities are comprised of securities that are both actively traded and not 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. These investments are measured based on observable prices on major exchanges. As of December 31, 2013 and 2012, substantially all of the significant inputs to these asset exchange values represented Level 1 independent active exchange market price inputs. Inputs for certain trading securities that are not actively traded on major exchanges were classified as Level 2 inputs.

Commodity derivatives. The Company's commodity derivatives represent oil, NGL and gas swap contracts, collar contracts and collar contracts with short puts. The Company's asset and liability measurements for its oil, NGL and gas swap, collar and collar contracts with short puts represent Level 2 inputs in the hierarchy priority. The Company utilizes discounted cash flow and option-pricing models for valuing its commodity derivatives.

The asset and liability values attributable to the Company's commodity derivatives were determined based on inputs which include (i) the contracted notional volumes, (ii) independent active market price quotes, (iii) the applicable estimated credit-adjusted risk-free rate yield curve and (iv) the implied rate of volatility inherent in the collar and collar contracts with short puts, which is based on active and independent market-quoted volatility factors.

Interest rate derivatives. The Company's interest rate derivative assets and liabilities as of December 31, 2013 and 2012 represent interest rate swap contracts. The Company utilizes discounted cash flow models for valuing its interest rate derivatives. The net derivative values attributable to the Company's interest rate derivative contracts as of December 31, 2013 and 2012 are based on (i) the contracted notional amounts, (ii) LIBOR rate yield curves provided by counterparties and corroborated with forward active market-quoted LIBOR yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's interest rate derivative liability measurements represent Level 2 inputs in the hierarchy priority.

Assets and liabilities measured at fair value on a nonrecurring basis. Certain assets are measured at fair value on a nonrecurring basis. These assets are not measured at fair value on any ongoing basis, but are subject to fair value adjustments in certain circumstances. These assets can include long-lived assets that have been reduced to fair value when they are held for sale, inventory and proved and unproved oil and gas properties that are written down to fair value when they are impaired.

Proved oil and gas properties. During 2013, 2012 and 2011, reductions in management's longer-term commodity price outlooks ("Management's Price Outlooks") provided indications of possible impairment of the Company's predominately dry gas properties in the Raton field in southeastern Colorado, the Barnett Shale field in North Texas and the Edwards Trend and Austin Chalk fields in South Texas. As a result of management's assessments, during the years ended December 31, 2013, 2012 and 2011, the Company recognized impairment charges to reduce the carrying values of the Raton field, the Barnett Shale field and the Edwards Trend/Austin Chalk fields, respectively, to their estimated fair values. The impairment charge associated with the Barnett Shale field is reported in income (loss) from discontinued operations, net of tax in the accompanying consolidated statements of operations.

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The Company calculated the fair values of the Raton field, the Barnett Shale field and the Edwards Trend/Austin Chalk fields proved properties using a discounted cash flow model. Significant Level 3 assumptions associated with the calculation of discounted future cash flows included Management's Price Outlooks and management's outlooks for (i) production costs, (ii) capital expenditures, (iii) production and (iv) estimated proved reserves and risk-adjusted probable reserves. Management's Price Outlooks are developed based on third-party longer-term commodity futures price outlooks as of each measurement date. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value.
The following table presents the fair value and fair value adjustments (in millions) for the Company's 2013, 2012 and 2011 proved property impairments, as well as the average oil price per barrel ("BBL") and gas price per British thermal unit ("MMBTU") utilized in respective Management's Price Outlooks:

	Year ended	Fair	Fair Value	Management's Price Outlooks	
	December 31,	Value	Adjustment	Oil	Gas
Edwards Trend/Austin Chalk	2011	$189.9	$(354.4)	$92.69	$5.14
Barnett Shale	2012	$184.8	$(532.6)	$87.09	$4.78
Raton	2013	$533.6	$(1,495.2)	$80.40	$4.43

It is reasonably possible that the estimate of undiscounted future net cash flows attributable to these or other properties may change in the future resulting in the need to impair their carrying values. The primary factors that may affect estimates of future cash flows are (i) future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable and possible oil and gas reserves, (ii) results of future drilling activities, (iii) Management's Price Outlooks and (iv) increases or decreases in production and capital costs associated with these fields.
Assets classified as held for sale. The Company records assets classified as held for sale at the lower of the asset's carrying amount or estimated fair value less costs to sell. The fair value of Pioneer Alaska is based on an estimated sale price based on ongoing negotiations, less costs to sell, and is further supported by the Company's discounted cash flow model for the Alaska proved properties using Level 3 inputs as discussed in the proved oil and gas properties section above. The fair value of the Barnett Shale field assets is based upon a weighted average calculation that uses management inputs including an estimated sales price and a discounted cash flow model for the proved properties using Level 3 assumptions as discussed in the proved oil and gas properties section above. The fair value of the Sendero assets are based upon anticipated sales proceeds less costs to sell, which represent a Level 3 input in the hierarchy priority. See Note C for additional information regarding the Company's planned divestitures.
The following table presents the estimated fair value less costs to sell and fair value adjustments for the Company's assets classified as held for sale as of December 31, 2013:

	Estimated Fair Value Less Costs to Sell	Fair Value Adjustment
	(in millions)	
Discontinued operations held for sale - Alaska	$350.6	$(539.8)
Discontinued operations held for sale - Barnett Shale field	$180.4	$(189.5)
Other long-lived assets held for sale - Sendero	$31.4	$(25.5)

Unproved oil and gas properties. During December 2012, the Company recorded an impairment charge to reduce the carrying value of unproved properties in the Barnett Shale field of $71.8 million (reported in income (loss) from discontinued operations, net of tax in the accompanying consolidated statements of operations). The Company calculated the estimated fair value of the Barnett Shale unproved properties using significant Level 3 assumptions based on average lease bonuses per acre for its Barnett liquid-rich acreage, allocating no value to dry gas acreage as

the Company does not intend to develop that acreage.

Inventories. During December 2013, the Company recorded an impairment charge of $23.2 million to reduce the carrying value of its excess vertical well pipe inventory. The Company calculated the estimated fair value of the inventory using significant

Level 2 assumptions based on third-party price quotes for the asset in an active market. The impairment charge is included in other expense on the Company's accompanying consolidated statements of operations.

Financial instruments not carried at fair value. Carrying values and fair values of financial instruments that are not carried at fair value in the consolidated balance sheet as of December 31, 2013 and 2012 are as follows:

	December 31, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in thousands)			
Long-term debt	$2,653,059	$3,018,830	$3,721,193	$4,555,770

Long-term debt includes the Company's credit facility and the Company's senior notes. At December 31, 2012, long-term debt also included Pioneer Southwest's credit facility and the Company's 2.875% Convertible Senior Notes due 2038 ("Convertible Senior Notes"), which were both fully extinguished during 2013. The fair value of debt is determined utilizing inputs that are Level 2 measurements in the fair value hierarchy.

Credit facilities. The fair values of the Company's and, through the date of the merger, Pioneer Southwest's credit facilities are calculated using a discounted cash flow model based on (i) forecasted contractual interest and fee payments, (ii) forward active market-quoted United States Treasury Bill rate (in the case of the Company's credit facility) or LIBOR (in the case of Pioneer Southwest's credit facility) yield curves and (iii) the applicable credit-adjustments.

Senior notes. The Company's senior notes represent debt securities that are not actively traded on major exchanges. The fair values of the Company's senior notes are based on their periodic values as quoted on the major exchanges.

The Company has other financial instruments consisting primarily of cash equivalents, receivables, prepaid expenses, payables and other current assets and liabilities that approximate fair value due to the nature of the instrument and relatively short maturities. Non-financial assets and liabilities initially measured at fair value include certain assets acquired and liabilities assumed in a business combination, goodwill and asset retirement obligations.

Concentrations of credit risk. As of December 31, 2013, the Company's primary concentration of credit risks are the risks of collecting accounts receivable – trade and the risk of counterparties' failure to perform under derivative obligations. See Note L 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 asset receivables from the defaulting party. See Note E for additional information regarding the Company's derivative activities and information regarding derivative net assets and liabilities by counterparty.

NOTE E. Derivative Financial Instruments

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 or consumes, (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.

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Oil production derivative activities. All material physical sales contracts governing the Company's oil production are tied directly to, or are highly correlated with, New York Mercantile Exchange ("NYMEX") West Texas Intermediate ("WTI") oil prices. The Company uses derivative contracts to manage oil price volatility and basis swap contracts to reduce basis risk between NYMEX prices and actual index prices at which the oil is sold.
The following table sets forth the volumes per day in BBLs associated with the Company's outstanding oil derivative contracts as of December 31, 2013 and the weighted average oil prices per BBL for those contracts:

	2014	2015	2016
Swap contracts:			
Volume (BBLs)	10,000	—	—
Average price per BBL	$93.87	$—	$—
Collar contracts with short puts:			
Volume (BBLs)	69,000	85,000	25,000
Average price per BBL:			
Ceiling	$114.05	$98.98	$93.30
Floor	$93.70	$88.06	$85.00
Short put	$77.61	$73.06	