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

FORM 10-K

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

For the fiscal year ended December 31, 2017

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** ☒ **No** ☐

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

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§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	☒	**Accelerated filer**	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	**Smaller reporting company**	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter	**$ 26,939,176,465**
Number of shares of Common Stock outstanding as of February 14, 2018	**170,300,825**

DOCUMENTS INCORPORATED BY REFERENCE:

(1) Portions of the Definitive Proxy Statement for the Company's Annual Meeting of Shareholders to be held during May 2018 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.
- ***"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.
- ***"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.
- ***"GHG"*** means green house gases.
- "***HH***" means Henry Hub, a distribution hub on the natural gas pipeline in Louisiana that serves as the delivery location for futures contracts on the NYMEX.
- ***"LIBOR"*** means London Interbank Offered Rate, which is a market rate of interest.
- "***LLS***" means Louisiana light sweet oil, a light, sweet blend of oil produced from the Gulf of Mexico.
- ***"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.
- ***"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.
- ***"Proved reserves"*** mean those 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.

(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.

- ***"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.
- ***"SEC"*** means the United States Securities and Exchange Commission.
- ***"Standardized Measure"*** means the after-tax present value of estimated future net cash flows of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs employed in the determination of proved reserves and a ten percent discount rate.
- ***"U.S."*** means United States.
- ***"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.
- 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.

PART I

ITEM 1. BUSINESS

General

Pioneer is a large independent oil and gas exploration and production company that explores for, develops and produces oil, NGLs and gas within the United States. The Company is a Delaware corporation, and its common stock has been listed and traded on the NYSE under the ticker symbol "PXD" since its formation in 1997.

The Company's principal executive office is located at 5205 N. O'Connor Blvd., Suite 200, Irving, Texas 75039. The Company also maintains an office in Midland, Texas and field offices in its areas of operation.

At December 31, 2017, Pioneer had 3,836 employees, 1,423 of whom were employed in field and plant operations and 1,010 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. In addition to the reports filed or furnished with the SEC, Pioneer publicly discloses information from time to time in its press releases, investor presentations posted on its website and in publicly accessible conferences. Such information, including information posted on or connected to the Company's website, is not a part of, or incorporated by reference in, this Report or any other document the Company files with or furnishes to the SEC.

Mission and Strategies

The Company's mission is to be America's leading independent energy company, focused on value, safety, the environment, technology and our greatest asset, our people. The Company's long-term growth strategy is centered around the following strategic objectives:

- maintaining a strong balance sheet to ensure financial flexibility;
- delivering economic production and reserve growth;
- enhancing drilling, completion and production activities by utilizing the Company's scale and technology advancements to reduce costs and improve efficiency;
- developing and training employees and contractors to perform their jobs in a safe manner; and
- stewarding the environment through industry leading sustainable development efforts.

The Company's long-term strategy is primarily anchored by the Company's interests in the long-lived Spraberry/Wolfcamp oil field located in West Texas, which has an estimated remaining productive life in excess of 40 years. Underlying the Spraberry/Wolfcamp field is over 75 percent of the Company's total proved oil and gas reserves as of December 31, 2017.

In February 2018, the Company announced plans to divest its oil and gas production activities and development and exploration opportunities in the following areas:

- the Eagle Ford Shale gas and liquids field located in South Texas;
- the Raton gas field located in southern Colorado;
- the West Panhandle gas and liquids field located in the Texas Panhandle;
- the Edwards gas field located in South Texas; and
- the Sinor Nest Wilcox oil field located in South Texas.

No assurance can be given that the sales will be completed in accordance with the Company's plans or on terms and at prices acceptable to the Company.

Business Activities

Pioneer's purpose is to competitively and profitably explore for, develop and produce oil and gas reserves. In so doing, the Company sells homogeneous 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. The Company's portfolio of resources and opportunities are primarily located in the Spraberry/Wolfcamp oil field, and provide long-lived, dependable production and lower-risk exploration and development opportunities.

Petroleum industry. The petroleum industry has been operating in a lower oil price environment since late 2014, when North American oil prices began declining due to a worldwide oversupply of oil. During the fourth quarter of 2016, the Organization of Petroleum Exporting Countries ("OPEC") members and some nonmembers, led by Russia, pledged to reduce their oil output by roughly 1.8 million barrels a day from October 2016 levels in an effort to draw down a global oversupply and to rebalance supply and demand. The agreement became effective in January 2017 and was originally set to expire in March 2018. During November 2017, OPEC members and some nonmembers agreed to lengthen the output reductions through December 2018. These output reductions represented an unprecedented level of cooperation among oil-producing countries and, coupled with healthy oil demand, resulted in an increase in oil prices during 2017. In 2018, the worldwide demand for oil is expected to increase further as economic growth around the world is forecasted to be stronger than the last several years. This demand increase is expected to be met by higher supplies of oil from U.S. shale production growth and further oil inventory drawdowns. The Company expects ongoing oil price volatility as compliance with the output reduction agreement, changes in oil inventories and actual demand growth is reported.

The growth of unconventional shale drilling in the United States has substantially increased the supply of gas and NGLs, resulting in a significant decline in related prices as the supply of these products has grown. While the industry has invested in initiatives designed to increase takeaway capacity, such as the construction of liquefied natural gas ("LNG") and NGL export facilities, the supply of these products has exceeded the overall United States and international demand for these commodities. NGL products and gas supplies are expected to increase during 2018, which is expected to cause prices to decline slightly or remain flat during 2018.

Significant factors that are likely to affect 2018 commodity prices include: the effect of new policies enacted by the President of the United States and his administration; fiscal challenges facing the United States federal government; enacted changes to the tax laws in the United States; expected economic growth throughout the world; political and economic developments in North Africa and the Middle East; forecasted increased demand from Asian and European markets; the extent to which members of OPEC and other oil exporting nations adhere to and agree to extend the agreed oil production cuts, which expire in December 2018; 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 incremental LNG export capacity additions and the pace that gas storage is refilled during the year given that gas storage levels are anticipated to be at normal levels 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. The Company has entered into commodity derivative contracts for a large portion of its forecasted production for 2018 and, to a lesser extent, its forecasted 2019 production; however, commodity prices are volatile and if commodity prices decline, the Company could realize lower prices for unprotected volumes and could see a reduction in the prices at which the Company is able to enter into derivative contracts on additional volumes in the future. As a result, the Company's internal cash flows will be negatively impacted by a reduction in commodity prices. 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, 2017, and subsequent changes to these positions.

Liquidity. In spite of the lower commodity price environment, the Company has maintained a strong liquidity position. The Company's primary needs for cash are for capital expenditures, acquisitions of oil and gas properties, vertical integration assets and facilities, payments of contractual obligations, including debt maturities, dividends, share repurchases and working capital obligations. Principal sources of liquidity include cash and cash equivalents, net cash provided by operating activities, short-term and long-term investments, proceeds from divestitures and proceeds from financing activities (principally borrowings under the Company's credit facility or issuances of debt or equity securities). If internal cash flows 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 (i) by using cash on hand, (ii) through sales of short-term and long-term investments, (iii) with borrowings under the Company's credit facility, (iv) through issuances of debt or equity securities or (v) through other sources, such as sales of nonstrategic 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 controllable costs associated with production activities. For the year ended December 31, 2017, the Company's production of 99 MMBOE, excluding field fuel usage, represented a 16 percent increase compared to production during 2016. Production, price and cost information with respect to the Company's properties for 2017, 2016 and 2015 is set forth in "Item 2. Properties — Selected Oil and Gas Information — Production, price and cost data."

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. 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, negotiations of letters of intent or negotiations 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 materially and adversely affect its business."

During 2017, 2016 and 2015, the Company spent $136 million, $446 million and $36 million, respectively, primarily to purchase undeveloped acreage for future exploitation and exploration activities in the Spraberry/Wolfcamp field of the Permian Basin.

2016 Permian Basin acquisition. The Company's 2016 acquisition activities included the August 2016 acquisition of 28,000 net acres in the Permian Basin, with net production of approximately 1,400 BOEPD, from an unaffiliated third party for $428 million, including normal closing adjustments. The fair value of the assets acquired included $347 million of unproved property, $79 million of proved property and $5 million of other property and equipment. The fair value of the asset retirement obligations and other liabilities assumed were $2 million and $1 million, respectively.

Exploratory activities. The Company has devoted significant efforts and resources to hiring and developing a highly skilled geoscience, engineering and land 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."

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, 2017, the Company drilled 181 gross (130 net) development wells, with 100 percent of the wells being successfully completed as productive wells, at a total drilling cost (net to the Company's interest) of $2.0 billion.

The Company believes that its current property base provides a substantial inventory of prospects for future reserve, production and cash flow growth. The Company's proved reserves as of December 31, 2017 include proved undeveloped reserves and proved developed non-producing reserves of 45 MMBbls of oil, 22 MMBbls of NGLs and 291 Bcf of gas. The timing of the development of these proved reserves will be dependent upon commodity prices, drilling and operating costs and the Company's expected operating cash flows and financial condition.

Integrated services. The Company continues to utilize its integrated services to control well costs and operating costs in addition to supporting the execution of its drilling and production activities. The Company owns fracture stimulation fleets totaling approximately 470,000 horsepower that support its drilling operations. The Company also owns other field service equipment that support its drilling and production operations, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. In addition, Pioneer Sands LLC, the Company's wholly-owned sand mining subsidiary, is supplying high-quality brown sand for proppant, which is being used by the Company to fracture stimulate horizontal wells in the Spraberry and Wolfcamp Shale intervals.

The Company is also constructing a field-wide water distribution system to reduce the cost of water for drilling and completion activities and to secure adequate supplies of water to support the Company's long-term growth plan for the Spraberry/Wolfcamp field. During 2017, the Company expanded its mainline system, subsystems and frac ponds to efficiently deliver water to Pioneer's drilling locations. The Company is purchasing up to 120 thousand barrels per day of effluent water from the City of Odessa and has signed an agreement with the City of Midland to upgrade the city's wastewater treatment plant in return for a dedicated long-term supply of water from the plant. Once the upgrade to the wastewater treatment plant is complete, the Company expects to receive approximately two billion barrels of low-cost, non-potable water over a 28-year contract period (up to 240 thousand barrels per day) to support its completion operations.

Asset divestitures. The Company regularly reviews its asset base for the purpose of identifying nonstrategic assets, the disposition of which would increase capital resources available for other activities, create organizational and operational efficiencies and further the Company's objective of maintaining a strong balance sheet to ensure financial flexibility. In February 2018, the Company announced its intention to divest its properties in South Texas, Raton and the West Panhandle field and focus its efforts and capital resources to its Permian Basin assets. No assurance can be given that the sales will be completed in accordance with the Company's plans or on terms and at prices acceptable to the Company.

Permian Basin. In April 2017, the Company completed the sale of approximately 20,500 acres in the Martin County region of the Permian Basin, with net production of approximately 1,500 BOEPD, to an unaffiliated third party for cash proceeds of $264 million. The sale resulted in a gain of $194 million. In conjunction with the divestiture, the Company reduced the carrying value of goodwill by $2 million, reflecting the portion of the Company's goodwill related to the assets sold.

EFS Midstream. In July 2015, the Company completed the sale of its 50.1 percent equity interest in EFS Midstream LLC ("EFS Midstream") to an unaffiliated third party, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing and the remaining $501 million was received in July 2016. The Company recorded a net gain on the disposition of $777 million in September 2015.

The Company will continue to review its acreage in the Permian Basin and negotiate with other operators in the area to sell or trade nonstrategic properties to achieve operating efficiencies and to improve profitability. See Notes C and D 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 impairments. Also see "Item 1A. 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 a discussion of risks associated with planned 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 regarding price risk.

Seasonal nature of business. Generally, but not always, the demand for gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers may impact general seasonal changes in demand.

Significant purchasers. During 2017, the Company's significant purchasers of oil, NGLs and gas were Occidental Energy Marketing Inc. (24 percent), Sunoco Logistics Partners L.P. (14 percent) and Plains Marketing LP (10 percent). 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 the Company's ability to sell its oil, NGL and gas production. See "Item 1A. Risk Factors - The Company may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export facilities to market its oil, NGL and gas production; the Company relies on a limited number of purchasers for a majority of its products" and Note L of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about infrastructure capacity risks and the Company's significant customers.

Derivative risk management activities. The Company primarily utilizes commodity swap contracts, collar contracts and collar contracts with short puts that are intended 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 derivative contracts intended to reduce the effect of interest rate volatility on the Company's indebtedness and marketing derivatives to mitigate price risk associated with buy and sell marketing arrangements to fulfill firm pipeline transportation commitments. 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 2017, 2016 and 2015, as well as the Company's open commodity derivative positions at December 31, 2017, and subsequent changes to those positions.

Competition, Markets and Regulations

Competition. The oil and gas industry is highly competitive in the exploration for and acquisition of reserves, the acquisition of oil and gas leases and the hiring and retention of staff necessary for the identification, evaluation and acquisition and development of such properties. The Company's competitors include a large number of companies, including major integrated oil and gas companies, other independent oil and gas companies, and individuals engaged in the exploration for and development of oil and gas properties. Some of the Company's competitors are substantially larger and have financial and other resources greater than those of the Company; as such, the Company may be at a competitive disadvantage in the identification, acquisition and development of properties that complement the Company's operations.

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. 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.

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 commodity prices or the degree to which commodity 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 many requirements, including 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 federal, state and local laws and regulations governing worker health and safety, the discharge of materials into the environment and environmental protection. Numerous governmental entities, including the U.S. Environmental Protection Agency (the "EPA"), the U.S. Occupational Safety and Health Administration (the "OSHA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause the Company to incur significant capital expenditures or take costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, imposition of investigatory remedial or corrective action of obligations, the occurrence of delays or restrictions in permitting or the performance of projects and the issuance of orders enjoining the Company from conducting certain operations in a particular area. While the Company's environmental compliance costs have historically not had a material adverse effect on its results of operations, there can be no assurance that such costs will not be material in the future, or that new or more stringently applied laws and regulations will not materially increase the cost of doing business.

The following is a summary of the more significant environmental and worker health and safety laws, as amended from time to time, to which the Company's business operations are or may be subject and with which compliance or the failure to maintain compliance may have a material adverse effect on the Company's capital expenditures, results of operations or financial position.

Hazardous wastes and substances. 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 authority delegated by the EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. The Company generates some amounts of ordinary industrial wastes that may be regulated as RCRA hazardous wastes. RCRA currently excludes drilling fluids, produced waters and certain other wastes associated with the exploration, development and production of oil or gas from the definition of hazardous waste. These wastes are instead regulated under RCRA's less stringent non-hazardous waste provisions. There have been efforts from time to time to remove this exclusion, which removal could have a material adverse effect on the Company's results of operations and financial position, and it is possible that certain oil and gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. For example, in response to a lawsuit filed by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into a settlement agreement that was finalized in a consent decree issued by the U.S. District Court for the District of Columbia in December 2016, whereby the EPA is required to propose no later than March 15, 2019, a rulemaking for the revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations, the decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021.

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. It is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Company generates materials in the course of its operations that may be regulated as CERCLA hazardous substances.

See "Item 1A. Risk Factors - The nature of the Company's assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company" for further discussion on environmental contamination issues.

Water use, surface discharges and discharges into belowground formations. 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 hazardous substances, into waters of the United States and state waters. Spill prevention, control and countermeasure plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture or leak. Additionally, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of stormwater runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material into regulated waters, including wetlands, unless authorized by an appropriately issued permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the CWA and analogous state laws.

The federal Oil Pollution Act ("OPA") sets minimum standards for prevention, containment and cleanup of oil spills into waters of the United States. Under OPA, responsible parties, including owners and operators of onshore facilities, such as exploration and production facilities, may be held strictly liable for oil spill cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. OPA amends the CWA and thus noncompliance with OPA could result in civil and criminal penalties under the CWA.

In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States, but legal challenges to this rule followed and the rule was stayed nationwide by the U.S. Sixth Circuit Court of Appeals in October 2015 pending resolution of the court challenges. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rests with the federal district or appellate courts. Additionally, following the issuance of a presidential executive order to review the rule, the EPA and the Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule. The EPA and the Corps also announced their intent to issue a new rule defining the CWA's jurisdiction. On November 22, 2017, the EPA and the Corps published a proposed rule specifying that the contested June 2015 rule would not take effect until two years after the rule proposed on November 22, 2017 is finalized and published in the federal register. As a result, future implementation of the June 2015 rule is uncertain at this time. To the extent this rule or a revised rule expands the scope of the CWA's jurisdiction, the Company could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities.

The Company may dispose of produced water from oil and gas activities in underground wells, which are designed and permitted to place the water into non-productive geologic formations that are isolated from fresh water sources. The Underground Injection Control ("UIC") program established under the federal Safe Drinking Water Act ("SDWA") requires issuance of permits from the EPA or an analogous state agency for the construction and operation of disposal wells. Additionally, the UIC program establishes minimum standards for disposal well operations and restricts the types and quantities of fluids that may be disposed. Because some states have become concerned that the disposal of produced water into below ground formations could contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal. Should future onerous regulations or bans relating to underground wells be placed in effect in areas where the Company has significant operations, there could be an adverse impact on the Company's ability to operate. See "Item 1A. Risk Factors - Pioneer's operations are substantially dependent on the availability of water and its ability to dispose of produced water gathered from drilling and production activities and restrictions on the Company's ability to obtain water or dispose of produced water may have a materially adverse effect on its financial condition, results of operations and cash flows" for further discussion on seismicity issues.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice to stimulate production of oil and gas from dense subsurface rock formations. The process involves the injection of water, sand and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and gas production. The Company routinely conducts hydraulic fracturing in its drilling and completion programs. The process is typically regulated by state oil and gas commissions, but, in recent years, several federal, state and local agencies have asserted regulatory authority over certain aspects of the process. Additionally, from time to time, the U.S. Congress has considered legislation that would provide for federal regulation of hydraulic fracturing and disclosure of chemicals used in the fracturing process but, to date, no such federal legislation has been adopted. The Company participates in FracFocus, a national publicly accessible internet-based registry managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission. FracFocus provides the public access to Company-reported information on the additives it uses in the hydraulic fracturing process on wells the Company operates. In the event federal, state or local restrictions are adopted in areas where the Company is currently conducting operations, 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 the volume that the Company is ultimately able to produce from its reserves.

See "Item 1A. Risk Factors - 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 materially and adversely affect the Company's production" for further discussion on hydraulic fracturing issues.

Air emissions. The federal Clean Air Act (the "CAA") and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other compliance requirements. Such laws and regulations could require a facility to obtain pre-approval for construction or modification projects expected to produce air emissions or result in the increase of existing air emissions. Additionally, these legal requirements could impose stringent air permit conditions or utilize specific emission control technologies to limit emissions of certain air pollutants. 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. See "Item 1A. Risk Factors - The Company's operations are subject to stringent environmental and oil and gas-related laws and regulations that could cause it to suspend or curtail its operations or expose it to material costs and liabilities" for further discussion on air emission issues.

Climate change. Climate change continues to attract considerable public, political and scientific attention. As a result, numerous proposals have been made, and are likely to continue to be made, at the international, national, regional and state levels of government to monitor and limit emissions of greenhouse gases ("GHGs"). These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs from the Company's equipment and operations 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. See "Item 1A. Risk Factors - 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, and the potential physical effects of climate change could disrupt the Company's production and cause it to incur significant costs in preparing for or responding to those effects" for further discussion on climate change issues.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on species listed as threatened or endangered under the ESA. 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. See "Item 1A. Risk Factors - Laws and regulations pertaining to threatened and endangered species could delay or restrict the Company's operations and cause it to incur substantial costs" for further discussion on endangered species issues.

Activities on federal lands. Oil and gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the federal Bureau of Land Management (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 some of the Company's 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. Moreover, depending on the mitigation strategies recommended in the Environmental Assessments, the Company could incur added costs, which could be substantial.

Occupational health and safety. The Company's operations are subject to the requirements of the federal Occupational Safety and Health Act and comparable state statutes. These laws and the related regulations issued by OSHA strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of CERCLA and similar state statutes require that the Company organize or disclose information about hazardous materials used or produced in the Company's operations.

Additionally, the Company's sand mining operations are subject to mining safety regulation. The U.S. Mining Safety and Health Administration ("MSHA") is the primary regulatory organization that regulates quarries, surface mines, underground mines and the industrial mineral processing facilities associated with and located at quarries and mines. 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.

OSHA promulgated new rules in March 2016 for workplace exposure to respirable silica for several other industries. Respirable silica is a known health hazard for workers exposed over long periods. The MSHA has been considering the adoption of similar rules. If any new rule issued by MSHA lowers the workplace exposure limit significantly, the Company could incur significant capital and operating expenditures for equipment to reduce this exposure.

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 that are 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 the 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 production rates. 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 that the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, NGLs 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 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, such as the Company, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. The EPAct 2005 also gives FERC authority to impose civil penalties of up to $1 million per day for each violation of the Natural Gas Act ("NGA"), the Natural Gas Policy Act of 1978 and related regulations.

Under FERC Order 704, which regulates annual gas transaction reporting requirements, 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 by May 1 of the year following the calendar year when such sales and purchases occurred. Form No. 552 contains aggregate volumes of wholesale gas purchased or sold in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. 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.

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, vary from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state legislatures, 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 believes that the regulation of intrastate gas pipeline transportation rates will not affect its operations in any way that is materially different from the effects on its similarly situated competitors.

Natural gas processing. The Company's gas processing operations are generally not subject to FERC or state regulation with respect to rates or terms and conditions of service. There can be no assurance that the Company's processing operations will continue to be unregulated in the future. However, although the processing facilities may not be directly regulated, 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 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 the 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. 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. Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also 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 the 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 the FERC.

Rates of interstate liquids pipelines are currently regulated by the FERC, primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in July 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23 percent. This adjustment is subject to review every five years. Under the 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.

In November 2009, the Federal Trade Commission (the "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 million per violation per day, subject to annual inflation adjustment. The Commodity Futures Trading Commission (the "CFTC") has also issued anti-manipulation rules that subject violators to a civil penalty of up to the greater of $1 million per violation, subject to annual inflation adjustment, or triple the monetary gain to the person for each violation. See "Items 1A. Risk Factors - The Company's transportation of gas, sales and purchases of oil, NGLs, gas or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks."

Energy commodity prices. Sales prices of oil, condensate, NGLs and gas are not currently regulated and sales 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 or 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, NGLs and gas are highly volatile and have declined significantly in recent years. A sustained decline in these commodity prices could materially and adversely affect the Company's business, 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, NGLs 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, NGLs and gas;
- the price and quantity of foreign imports of oil, NGLs and gas;
- worldwide oil, NGL and gas inventory levels, including at Cushing, Oklahoma, the benchmark location for WTI oil prices, and the U.S. Gulf Coast, where the majority of the U.S. refinery capacity exists;
- volatility and trading patterns in the commodity-futures markets;
- the capacity of U.S. and international refiners to utilize U.S. supplies of oil and condensate;
- weather conditions;
- overall domestic and global political and economic conditions;
- actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- the effect of oil, NGL and LNG imports to and exports from the U.S.;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign governmental regulations, including environmental regulations, and taxation;
- the effect of energy conservation efforts;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil and gas so as to minimize emissions of carbon dioxide and methane GHGs;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- the price, availability and acceptance of alternative fuels.

In the past, commodity prices have been extremely volatile, and the Company expects this volatility to continue. For the five years ended December 31, 2017, oil prices fluctuated from a high of $110.53 per Bbl in 2013 to a low of $26.21 per Bbl in 2016 while gas prices fluctuated from a high of $6.15 per Mcf in 2014 to a low of $1.64 per Mcf in 2016. Likewise, NGLs have suffered significant recent declines. NGLs are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in commodity prices could materially and adversely affect the Company's future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. 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 materially and adversely affect the amount of oil, NGLs and gas that the Company can produce economically, which may result in the Company having to make significant downward adjustments to its estimated proved reserves. A reduction in production could also 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's derivative risk management activities could result in financial losses; the Company may not enter into derivative arrangements with respect to future volumes if prices are unattractive.

To mitigate the effect of commodity price volatility on the Company's net cash provided by operating activities and its net asset value, 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. Although the Company has entered into commodity derivative contracts for a large portion of its forecasted production through 2018, the volumes of protected production for 2019 and future years is substantially less. 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 future volumes. This could make such transactions unattractive, and, as a result, some or all of the Company's production volumes forecasted for 2019 and beyond may not be protected by derivative arrangements. In addition, the Company's derivatives arrangements may not achieve their intended strategic purposes.

Finally, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted in July 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. Regulation by the CFTC and banking regulators may materially and adversely affect the cost and availability of derivatives, including by causing the Company's contract counterparties, which are generally financial institutions and other market participants, to curtail or cease their derivatives activities.

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. The Company is unable to predict changes in a counterparty's creditworthiness or ability to perform. Even if the Company accurately predicts sudden changes, the Company's ability to negate the risk may be limited depending upon market conditions and the contractual terms of the transactions. During periods of declining commodity prices, the Company's derivative receivable positions generally increase, which increases the Company's counterparty credit exposure. If any of the Company's 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 and could increase the likelihood that the Company's derivative arrangements may not achieve their intended strategic purposes.

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;
- unexpected pressure or irregularities in formations;
- equipment failures or accidents;
- construction delays;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- restricted access to land for drilling or laying pipelines;

- title defects;
- lack of available gathering, transportation, processing, fractionation, storage, refining or export facilities;
- lack of available capacity on interconnecting transmission pipelines;
- 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; and
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements.

The Company's future drilling activities may not be successful and, if unsuccessful, the Company's proved reserves and production would decline, which 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 2018.

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

Significant or extended price declines could result in the Company having to make downward adjustments to the carrying value of its proved oil and gas properties. The Company performs assessments of its 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) proved reserves and risk-adjusted probable and possible reserves, (ii) commodity prices, (iii) production costs, (iv) capital expenditures and (v) production. 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 2017 the Company recognized an impairment charge of $285 million attributable to its Raton field in southeast Colorado, and in 2016 the Company recognized an impairment charge of $32 million attributable to its West Panhandle field assets in the panhandle region of Texas, primarily due to declines in commodity prices and downward adjustments to the economically recoverable reserves attributable to each asset. The Company may incur impairment charges in the future, which could materially affect the Company's results of operations in the period incurred. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Impairment of oil and gas properties and other long-lived assets" and Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for further information on the Company's impairment charges.

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

At December 31, 2017, the Company carried unproved oil and gas property costs of $558 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 the 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, 2017, the Company had a carrying value for goodwill of $270 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 (i) additional reserve adjustments both positive and negative, (ii) results of drilling activities, (iii) management's outlook for commodity prices and costs and expenses, (iv) changes in the Company's market capitalization, (v) changes in the Company's weighted average cost of capital and (vi) changes in income taxes. 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 materially and adversely affect its business.

Acquisitions of producing oil and gas properties have from time to time contributed to the Company's growth. Acquisition opportunities in the oil and gas industry are very competitive, which can increase the cost of, or cause the Company to refrain from, completing acquisitions. The success of any acquisition will depend on a number of factors and involves potential risks, including, among other things:

- the inability to estimate accurately the costs to develop the reserves, the recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;
- the assumption of unknown liabilities, including environmental liabilities, and 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 pre-closing matters, such as matters of litigation, environmental contingencies, royalty obligations and income taxes. 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 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, and water distribution and disposal activities, are subject to all the risks incident to the oil and gas development and production business, including:

- blowouts, cratering, explosions and fires;
- adverse weather effects;
- environmental hazards, such as NGL and gas leaks, oil and produced water spills, pipeline and vessel ruptures, encountering naturally occurring radioactive materials ("NORM"), and unauthorized discharges of toxic chemicals, gases, brine, well stimulation and completion fluids or other pollutants onto the surface or into the subsurface environment;
- high costs, shortages or delivery delays of equipment, labor or other services or water and sand for hydraulic fracturing;
- facility or equipment malfunctions, failures or accidents;
- title problems;
- pipe or cement failures or casing collapses;
- uncontrollable flows of oil or gas well fluids;
- compliance with environmental and other governmental requirements;
- lost or damaged oilfield workover and service tools;
- surface access restrictions;
- unusual or unexpected geological formations or pressure or irregularities in formations;
- terrorism, vandalism and physical, electronic and cyber security breaches; and
- natural disasters.

The Company's overall exposure to operational risks may increase as its drilling activity expands and as it increases internally-provided fracture stimulation, water distribution, water disposal and other services. 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.

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, 2017, the Company owned interests in 10 gas processing plants and four treating facilities. The Company is the operator of one of the gas processing plants and all four of the treating facilities. Nine of the gas processing plants are operated by third parties and one of the treating facilities is not currently being used. 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.

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.

Drilling in emerging areas is more uncertain than drilling in areas that are more developed and have a longer history of established drilling operations. 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 charges to reduce the carrying value of its unproved properties in those areas.

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, 2017 include proved undeveloped reserves and proved developed non-producing reserves of 45 MMBbls of oil, 22 MMBbls of NGLs and 291 Bcf of gas. The Company's ability to drill and develop these locations depends on a number of factors, including the availability and cost of capital, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. There can be no assurance that the Company will drill these locations or that the Company will be able to produce oil or gas reserves from these locations or any other potential drilling locations. Well results vary by formation and geographic area, and the Company's drilling activities are generally focused on remaining locations that are believed to offer the highest return. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could materially and 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 materially and 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 material adverse effect on the Company's proved reserves, financial condition and results of operations.

A portion of the Company's total estimated proved reserves at December 31, 2017 were undeveloped, and those proved reserves may not ultimately be developed.

At December 31, 2017, approximately eight percent of the Company's total estimated proved reserves were undeveloped. Recovery of undeveloped proved reserves requires significant capital expenditures and successful drilling. The Company's reserve data assumes that the Company can and will make these expenditures and conduct these operations successfully, which assumptions may not prove correct. If the Company chooses not to spend the capital to develop these proved undeveloped reserves, or if the Company is not otherwise able to successfully develop these proved undeveloped reserves, the Company will be required to write-off these proved reserves. In addition, under the SEC's rules, because proved undeveloped reserves may be booked only if they relate to wells planned to be drilled within five years of the date of booking, the Company may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. As with all oil and gas leases, the Company's leases require the Company to drill wells that are commercially productive and to maintain the production in paying quantities, and if the Company is unsuccessful in drilling such wells and maintaining such production, the Company could lose its rights under such leases. The Company's future production levels and, therefore, its future cash flow and income are highly dependent on successfully developing its proved undeveloped leasehold acreage.

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 and other financial and operating results. These forecasts are based on a number of estimates and assumptions, including that none of the risks associated with the Company's oil and gas operations summarized in this "Item 1A. Risk Factors" occur. Production forecasts, specifically, are based on assumptions such as:

- expectations of production from existing wells and future drilling activity;
- the absence of facility or equipment malfunctions;
- the absence of adverse weather effects;
- expectations of commodity prices, which could experience significant volatility;
- expected well costs; and
- the assumed effects of regulation by governmental agencies, which could make certain drilling activities or production uneconomical.

Should any of these assumptions prove inaccurate, or should the Company's development plans change, actual production could be materially and adversely affected.

Because the Company's proved reserves and production decline continually over time, the Company will need to mitigate these declines through drilling and production enhancement initiatives and/or acquisitions.

Producing oil and gas reservoirs are characterized by declining production rates, which vary depending upon reservoir characteristics and other factors. Because the Company's proved reserves and production decline continually over time as those reserves are produced, the Company will need to mitigate these declines through drilling and production enhancement initiatives and/or acquisitions of additional recoverable reserves. There can be no assurance that the Company will be able to develop, exploit, find or acquire sufficient additional reserves to replace its current or future production.

The Company may not be able to obtain access on commercially reasonable terms or otherwise to pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export 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, NGLs and gas production depends in large part on the availability, proximity and capacity of pipelines and storage facilities, gathering systems and other transportation, processing, fractionation, refining and export 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, fractionation, refining or export facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist.

For example, following Hurricane Harvey in 2017 and Hurricanes Gustav and Ike in 2008, certain Permian Basin gas processors were forced to shut down their plants due to the inability of certain Texas Gulf Coast NGL fractionators to operate. 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 limitations in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, storage, processing, fractionation, refining or export facilities, or lack of capacity at 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 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 a FERC-related 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's operations and drilling activity are concentrated in the Permian Basin of West Texas, an area 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; such concentration also makes the Company vulnerable to risks associated with operating in a limited geographic area.

The Company's producing properties are geographically concentrated in the Permian Basin of West Texas. At December 31, 2017, 77 percent of the Company's total estimated proved reserves were attributable to properties located in this area. In addition, the Company's operations and drilling activity are concentrated in this area where industry activity is high. As a result, demand for personnel, equipment, power, services and resources has increased, as well as the costs for these items. Any delay or inability to secure the personnel, equipment, power, services and resources could result in oil, NGL 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 results of operations, cash flow and profitability.

As a result of this concentration, the Company may be disproportionately exposed to the impact of delays or interruptions of operations or production in this area caused by external factors such as governmental regulation, state politics, market limitations, water or sand shortages or extreme weather related conditions.

Pioneer's operations are substantially dependent upon the availability of water and its ability to dispose of produced water gathered from drilling and production activities. Restrictions on the Company's ability to obtain water or dispose of produced water may have a material adverse effect on its financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Limitations or restrictions on the Company's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water districts taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If the Company is unable to obtain water to use in its operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on its financial condition, results of operations and cash flows.

In addition, the Company must dispose of the fluids produced from oil and gas production operations, including produced water, which it does directly or through the use of third party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern arises from recent seismic events near underground disposal wells that are used for the disposal by injection of produced water resulting from oil and gas activities. In March 2016, the United States Geological Survey identified Texas and Colorado as being among the states with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells to assess any relationship between seismicity and the use of such wells. For example, in Texas, the Texas Railroad Commission adopted new rules governing the permitting or re-permitting of wells used to dispose of produced water and other fluids resulting from the production of oil and gas in order to address these seismic activity concerns within the state. Among other things, these rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the state to modify, suspend or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity.

States may issue orders to temporarily shut down or to curtail the injection depth of existing wells in the vicinity of seismic events. Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by the Company or by commercial disposal well vendors whom the Company may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in the Company or its vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require the Company or its vendors to shut down or curtail the injection into disposal wells, which events could have a material adverse effect on the Company's business, financial condition and results of operations.

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 production and ad valorem taxes. Decreased levels of drilling activity in the oil and gas industry in recent periods have led to cost reductions for some drilling equipment, materials and supplies. However, such costs may rise faster than increases in the Company's revenue if commodity prices rise, 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 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, which could materially and adversely affect the Company's results of operations.

Absent an expansion of U.S. refining and export capacity, rising U.S. production of oil and condensates could result in a surplus of these products in the U.S., which would likely cause prices for these commodities to fall and markets to constrict. Although U.S. law was changed in 2015 to permit the export of oil, exports may not occur if demand is lacking in foreign markets or the price that can be obtained in foreign markets does not support associated export capacity expansions, transportation and other costs. 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 Company's operations are subject to stringent environmental and oil and gas-related laws and regulations that could cause it to suspend or curtail its operations or expose it to material costs and liabilities.

The Company's operations are subject to stringent federal, state and local laws and regulations governing, among other things, the drilling of wells, developing rates of production, the size and shape of drilling and spacing units or proration units, the transportation and sale of oil, NGLs and gas, and the discharging of materials into the environment and environmental protection. In connection with its operations, the Company must obtain and maintain numerous environmental and oil and gas-related permits, approvals, and certificates from various federal, state and local governmental authorities, and may incur substantial costs in doing so. The need to obtain permits has the potential to delay the development of oil and gas projects. Over the next several years, the Company may be charged royalties on gas emissions or required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in October 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion under standards to provide protection of public health and welfare. In November 2017, the EPA published a final rule that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either "attainment/unclassifiable" or "unclassifiable" but has not yet issued non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modify air pollution control systems to reduce or eliminate sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement regulations implementing the NAAQS rule that may be more stringent than the federal standards. In another example, in June 2016, the EPA published a final rule updating federal permitting regulations for stationary sources in the oil and gas industry by defining and clarifying the meaning of the term "adjacent" for determining when separate surface sites and the equipment at those sites will be aggregated for permitting purposes. Future compliance with these legal requirements or with any new or amended environmental laws or regulations could, among other things, delay, restrict or prohibit the issuance of necessary permits, increase the Company's capital expenditures and operating expenses by, for example, requiring installation of new emission controls on some of the Company's equipment, any one or more of which developments could have a material adverse effect on the Company's business, financial condition and results of operations.

There can be no assurance that present or future 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 materially and adversely affect the Company's future operations and financial condition. Noncompliance with these laws and regulations may subject the Company to sanctions, including administrative, civil or criminal penalties, remedial cleanups or corrective actions, delays in permitting or performance of projects, natural resource damages and other liabilities. Such laws and regulations may also affect the costs of acquisitions. In addition, these laws and regulations are subject to amendment or replacement by more stringent laws and regulations.

The nature of the Company's assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company.

The Company's assets and production operations may give rise to significant environmental costs and liabilities as a result of the Company's handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and due to past industry operations and waste disposal practices. The Company's oil and gas business involves the generation, handling, treatment, storage, transport and disposal of wastes, hazardous substances and petroleum hydrocarbons and is subject to environmental hazards, such as oil and produced water spills, NGL and gas leaks, pipeline and vessel ruptures and unauthorized discharges of such wastes, substances and hydrocarbons, that could expose the Company to substantial liability due to pollution and other environmental damage. The Company currently owns, leases or operates, and in the past has owned, leased or operated, properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes may have been released on or under such properties, or on or under other locations, including off-site locations, where such substances have been taken for treatment or disposal. These wastes, substances and hydrocarbons may also be released during future operations. In addition, some of the Company's properties have been operated by predecessors or previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company's control. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons, hazardous substances 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, hazardous substances 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. Such properties and the substances disposed or released on or under them may be subject to CERCLA, RCRA and analogous state laws, which could require the Company to remove previously disposed substances, wastes and petroleum hydrocarbons, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination, the costs of which could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company may not be able to recover some or any of these costs from sources of contractual indemnity or insurance, as 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 deductibles associated with obtaining such insurance.

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 and the potential physical effects of climate change could disrupt the Company's production and cause the Company to incur significant costs in preparing for or responding to those effects.

Climate change continues to attract considerable public, political and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. The EPA has, however, adopted regulations under the CAA that, among other things, establish certain permits and construction reviews designed to allow operations while ensuring the prevention of significant deterioration in air quality by GHG emissions from large stationary sources that are already potential sources of significant pollutant emissions. 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 from such sources. 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. Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and gas operations. In June 2016, the EPA published a final rule establishing New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and gas sector to reduce certain methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously issued New Source Performance Standards, published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. However, in June 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years and revisit the entirety of the 2016 standard, but has not yet published a final rule. As a result, future implementation of the 2016 standards is uncertain at this time. Furthermore, with respect to a final rule published by the BLM in November 2016 and imposing requirements to reduce methane emissions from venting, flaring and leaking on public lands, the BLM has since published a proposed rulemaking in October 2017 that would temporarily suspend certain requirements contained in the November 2016 final rule until January 17, 2019, but the October 2017 rulemaking has not yet been finalized.

At the state level, some states are considering and other states, including Colorado, where the Company conducts operations, have issued requirements for the performance of leak detection programs that identify and repair methane leaks at certain oil and gas sources. State rules may be more stringent than federal rules. Compliance with the EPA's June 2016, the BLM's November 2016 rule or with any future federal or state methane regulations could, among other things, require installation of new emission controls on some of the Company's equipment and significantly increase the Company's capital expenditures and operating costs.

Internationally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This "Paris agreement" was signed by the United States in April 2016 and entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. In August 2017, the U.S. State Department officially informed the United Nations of the United States' intention to withdraw from the Paris agreement. The Paris agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process and/or the terms on which the United States may re-enter the Paris agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any federal or state legislation or regulations or international agreements that require reporting of GHGs or otherwise restrict emissions of GHGs from the Company's equipment and operations 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 of which could have a material adverse effect on the Company's business, financial condition and results of operations. Moreover, such new legislation or regulatory programs as well as conservation plans and efforts undertaken in response to climate change could also materially and adversely affect demand for the oil, NGLs and gas the Company produces and lower the value of its reserves. Depending on the severity of any such limitations, the effect on the value of the Company's reserves could be material. In addition, recent non-governmental activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

Finally, it should be noted that 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, floods, droughts and other extreme climatic events. If any such effects were to occur, they could have a material adverse effect on the Company's exploration and production 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 materially 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 conducts hydraulic fracturing 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 in recent years, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. Additionally, the EPA has asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities. Moreover, in June 2016, the EPA published an effluent water final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly-owned wastewater treatment plants, and in 2014, the EPA issued a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands. However, with respect to this BLM rule, a Wyoming federal judge struck down this rule in June 2016, finding that the BLM lacked congressional authority to promulgate the rule, the BLM appealed the decision in July 2017, the appellate court issued a ruling in September 2017 to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in response to the BLM's issuance of a proposed rulemaking to rescind the 2015 rule and, on December 29, 2017, the BLM published a final rule rescinding the March 2017 rule.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the additives used in the hydraulic-fracturing process. In addition, certain states in which the Company operates, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, disposal and well-construction requirements on hydraulic-fracturing operations. States could elect to prohibit high volume hydraulic fracturing altogether, following the lead of New York. Also, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular although in May 2015 in response to one city in Texas voting to ban hydraulic fracturing within city limits the Texas Legislature adopted Texas House Bill 40, which provides that the regulation of oil and gas operations in Texas is under the exclusive jurisdiction of the state and preempted local regulation of those operations. Despite Texas House Bill 40, municipalities and political subdivisions in Texas continue to have the right to enact "commercially reasonable" regulations for surface activities. In the event federal, state or local restrictions pertaining to hydraulic fracturing are adopted in areas where the Company is currently conducting operations, 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 perhaps be limited or precluded in the drilling of wells or in the volume that the Company is ultimately able to produce from its reserves.

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, OPA and CERCLA. The U.S. Fish and Wildlife Service (the "FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. Any designation by the FWS of a critical or suitable habitat with respect to a threatened or endangered species 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, construction or releases of petroleum hydrocarbons, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties. Moreover, as a result of one or more settlements entered into by the FWS, the agency is required to make determinations on the potential listing of numerous species as endangered or threatened under the ESA. 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 delays or limitations on its development and production activities that could have a material adverse effect on the Company's ability to develop and produce reserves.

The Company is a party to debt instruments, a credit facility and other financial commitments that may restrict its business and financing activities.

The Company is a borrower under fixed rate senior notes and maintains a credit facility that is currently undrawn. 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. In addition, from time to time, the Company enters into arrangements and transactions that can give rise to material off-balance sheet obligations, including firm purchase, transportation and fractionation commitments, gathering, processing and transportation commitments on uncertain volumes of future throughput, operating lease agreements and drilling commitments. The Company's financial commitments could have important consequences to its business including, but not limited to, the following:

- the incurrence of charges associated with unused commitments if future events do not meet the Company's expectations at the time such commitments are entered into;
- increasing its vulnerability to adverse economic and industry conditions;
- limiting its flexibility to plan for, or react to, changes in its business and industry;
- limiting its ability to fund future development activities or engage in future acquisitions; and
- placing it at a competitive disadvantage compared to competitors that have less debt and/or fewer financial commitments.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Commitments, Capital Resources and Liquidity" and Notes G and J of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding the Company's outstanding debt and other commitments as of December 31, 2017 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. A ratings downgrade could materially and adversely impact the Company's ability to access debt markets, increase the borrowing cost under the Company's credit facility and the cost of future debt, and potentially require the Company to post letters of credit or other forms of collateral for certain obligations.

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 its properties.

Some of the Company's competitors are larger and have substantially greater financial and other resources than the Company. To a lesser extent, the Company also faces competition from companies that supply alternative sources of energy, such as wind or solar power. See "Item 1. Business - Competition, Markets and Regulations" for additional discussion regarding competition.

The Company's transportation of gas, sales and purchases of oil, NGLs, gas or other energy commodities, and any derivative activities related to such energy commodities, expose the Company to potential regulatory risks.

The 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 transportation of gas in interstate commerce, physical sales and purchases of oil, NGLs, gas 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. Failures to comply with such regulations, as interpreted and enforced, could materially and adversely affect the Company's 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 development costs, operating costs, severance, ad valorem and excise taxes, 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 historical 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 future 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 business could be materially and adversely 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. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. 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 and cash flows.

Cybersecurity attacks in particular are becoming more sophisticated. The Company relies extensively on information technology systems, including Internet sites, computer software, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting its business. The Company's technologies systems and networks, and those of its business associates may become the target of cybersecurity attacks, including without limitation malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems and materially and adversely affect the Company in a variety of ways, including the following:

- unauthorized access to and release of seismic data, reserves information, strategic information or other sensitive or proprietary information, which could have a material adverse effect on the Company's ability to compete for oil and gas resources;
- data corruption or operational disruption of production infrastructure, which could result in loss of production or accidental discharge;
- unauthorized access to and release of personal identifying information of royalty owners, employees and vendors, which could expose the Company to allegations that it did not sufficiently protect that information;
- a cybersecurity attack on a vendor or service provider, which could result in supply chain disruptions and could delay or halt operations; and
- a cybersecurity attack on third-party gathering, transportation, processing, fractionation, refining or export facilities, which could delay or prevent the Company from transporting and marketing its production, resulting in a loss of revenues.

These events could damage the Company's reputation and lead to financial losses from remedial actions, loss of business or potential liability. Additionally, certain cyber incidents, such as surveillance, may remain undetected for an extended period.

As cyber threats continue to evolve, the Company may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any information security vulnerabilities.

A failure by purchasers of the Company's production to satisfy their obligations to the Company could require the Company to recognize a 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 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.

Since 2016, the economies in the United States and certain countries in Europe and Asia have continued to stabilize with resulting improvements in industrial demand and consumer confidence. However, other economies, such as those of certain South American nations, continue to face economic struggles or slowing economic growth. If these conditions worsen, combined with a decline in economic growth in other parts of the world, there could be a significant adverse effect on global financial markets and commodity prices. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. 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 cash flows and profitability.

The Company's use of seismic data is subject to interpretation and may not accurately identify the presence of oil and gas, which could materially and adversely affect the results of its drilling operations.

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, the Company's drilling activities may not be successful or economic. In addition, the use of advanced technologies, such as 3-D seismic data, requires greater pre-drilling expenditures than traditional drilling strategies, and the Company could incur losses as a result of such expenditures.

The enactment of derivatives legislation could have a material 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 Act enacted in July 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. Although the CFTC has issued final regulations to implement significant aspects of the legislation, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

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 Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain futures and options contracts and equivalent swaps 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. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. 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 swaps that the Company uses. If the Company's swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, the Company may be required to clear such transactions. The ultimate effect of the proposed rules and any additional regulations on the Company's business is uncertain.

In addition, certain banking regulators and the CFTC have adopted final rules establishing minimum margin requirements for uncleared swaps. Although the Company expects to qualify for the end-user exception from margin requirements for swaps entered into to manage its commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that the Company uses. If any of the Company's swaps do not qualify for the commercial end-user exception, the posting of collateral could reduce its liquidity and cash available for capital expenditures and could reduce its ability to manage commodity price volatility and the volatility in its cash flows.

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 and reduce the Company's ability to monetize or restructure its existing derivative contracts. 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 materially and 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 materially and 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. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent the Company transacts with counterparties in foreign jurisdictions, it may become subject to such regulations. At this time, the impact of such regulations is not clear.

The future of the SEC and CFTC's rulemaking remains uncertain. Regulatory agendas that were released in late 2017 indicated that the SEC and CFTC plan to pursue fewer rulemaking items than in prior years. For example, the CFTC announced its intent to take action on an agency-wide internal review focused on simplifying and modernizing CFTC rules, regulations and practices and focus on streamlining the implementation of existing regulations and practices. Although the SEC and the CFTC's agendas are less expansive than they have been in the past, wholesale deregulation of the markets will not necessarily be the outcome. For example, the CFTC plans to take a new look at passing rules on position limits for certain futures contracts, and the SEC intends to re-propose rules for "plain vanilla" exchange-traded funds and add amendments to the Volcker Rule.

Moreover, regulation by the CFTC and banking regulators of the over-the-counter derivatives market and market participants could cause the Company's contract counterparties, which are generally financial institutions and other market participants, to curtail or cease their derivatives activities, which could materially and adversely affect the cost and availability of derivatives to the Company.

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 transactions 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 is 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, wastes, hazardous substances and other regulated 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 wastes, hazardous substances and other regulated 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 re-interpretation by more stringent and comprehensive legal requirements. While the Company's environmental compliance costs with existing laws and regulations have not historically had a material adverse effect on its results of operations, there can be no assurance that such costs will not be material in the future. Moreover, such future compliance with existing, new or amended 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 materially and 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 MSHA, 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 and amending legislation, which impose 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. This Act, as amended, is a strict liability statute and any failure by the Company to comply with such existing or any future standards, or any more stringent 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 governmental 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, mining and other permits and water rights and approvals authorizing operations at each sand mining facility.

In order to obtain permits, renewals of permits or other approvals 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 or approvals 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. Moreover, issuance of any permits, permit renewals or other approvals by governmental agencies may be conditioned on new or modified requirements or procedures with respect to mining that may be costly or time-consuming to implement. 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 or other approvals in the future.

The Company's sand mining operations and hydraulic fracturing may result in 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 personal injury lawsuits, recently adopted OSHA silica regulations and increased scrutiny by federal, state and local regulatory authorities.

Pioneer Sands LLC ("Pioneer Sands"), the Company's wholly-owned sand mining subsidiary, 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 Pioneer Sands or its commercial customers alleging damages caused by silica exposure. As of December 31, 2017, Pioneer Sands was the subject of silica exposure claims from 19 plaintiffs. Almost all of the claims pending against Pioneer Sands arise out of the alleged use of Pioneer Sands' sand products in foundries or as an abrasive blast media and have been filed in the states of Texas, Mississippi and Alabama, although some cases have been brought in other jurisdictions over the years.

It is possible that Pioneer Sands will have additional silica-related claims filed against it, including claims that allege silica exposure for periods for which there is not insurance coverage. In addition, it is possible that similar claims could be asserted arising out of the Company's other operations, including its hydraulic fracturing operations. Any pending or future claims or inadequacies of insurance coverage or contractual indemnification 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, 2017, 2016 and 2015 is based on evaluations prepared by the Company's engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"), with respect to the Company's major properties. 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 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.

Corporate Reserves is responsible for the management of the oil and gas proved reserve estimation processes in each of the Company's Permian Basin, South Texas, Raton and West Panhandle asset areas. Corporate Reserves is 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 oversight of the reservoir engineers by the Director of Corporate Reserves 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 Financial Officer and other executive officers. The reserve estimates are prepared by reservoir engineers before being submitted to the Director and Vice President of 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) 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 through internal Pioneer programs. Additionally, Corporate Reserves has prepared and maintains written policies and guidelines for its staff to reference on reserve estimation and preparation to promote consistency in the preparation of the Company's reserve estimates and compliance with the SEC reserve estimation and reporting rules.

Proved reserves audits. The proved reserve audits performed by NSAI for the years ended December 31, 2017, 2016 and 2015, in the aggregate, represented 77 percent, 77 percent and 82 percent of the Company's year-end 2017, 2016 and 2015 proved reserves, respectively; and 91 percent, 93 percent and 97 percent of the Company's year-end 2017, 2016 and 2015 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 their 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 proved 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 who 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 40 years of experience as a petroleum engineer, with 33 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 39 years of practical experience in petroleum engineering, including over 36 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.

Technologies used in proved 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.

Proved Reserves

As of December 31, 2017, 2016 and 2015, the Company's oil and gas proved reserves are located entirely in the United States. 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, 2017, 2016 and 2015:

	Summary of Oil and Gas Proved Reserves as of Fiscal Year-End Based on Average Fiscal-Year Prices				
	Proved Reserve Volumes				
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	%
December 31, 2017:					
Developed	442,364	189,434	1,629,451	903,373	92%
Undeveloped	40,525	21,063	122,429	81,993	8%
Total proved reserves	482,889	210,497	1,751,880	985,366	100%
December 31, 2016:					
Developed	343,515	126,928	1,215,861	673,085	93%
Undeveloped	34,681	10,013	48,868	52,840	7%
Total proved reserves	378,196	136,941	1,264,729	725,925	100%
December 31, 2015:					
Developed	266,657	112,376	1,284,680	593,146	89%
Undeveloped	45,313	13,968	71,807	71,249	11%
Total proved reserves	311,970	126,344	1,356,487	664,395	100%

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(a) Total proved gas reserves contain 171,623 MMcf, 137,853 MMcf and 144,955 MMcf of gas that the Company expected to be produced and used as field fuel (primarily for compressors), rather than being delivered to a sales point as of December 31, 2017, 2016 and 2015, respectively.

The Company's Standardized Measure of total proved reserves as of December 31, 2017 was $8.2 billion, including $7.7 billion and $443 million related to proved developed and proved undeveloped reserves, respectively. The Standardized Measure of total proved reserves as of December 31, 2017 includes the reduction of the federal corporate income tax rate to 21 percent associated with the enactment of the Tax Cut and Jobs Act. The Company's Standardized Measure of total proved reserves as of December 31, 2016 was $4.2 billion, including $4.0 billion and $178 million related to proved developed and proved undeveloped reserves, respectively. The Company's Standardized Measure of total proved reserves as of December 31, 2015 was $3.2 billion, including $3.0 billion and $245 million related to proved developed and proved undeveloped reserves, 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.

Description of Properties

The following tables summarize the Company's development and exploration/extension drilling activities during 2017:

	Development Drilling			
	Beginning Wells In Progress	Wells Spud	Successful Wells	Ending Wells In Progress
Permian Basin	8	22	16	14
South Texas—Eagle Ford Shale	4	1	5	—
South Texas—Other	—	5	5	—
Total	12	28	26	14

	Exploration/Extension Drilling				
	Beginning Wells In Progress	Wells Spud	Successful Wells	Unsuccessful Wells	Ending Wells In Progress
Permian Basin	119	214	207	1	125
South Texas—Eagle Ford Shale	14	10	15	1	8
West Panhandle	—	3	—	—	3
Total	133	227	222	2	136

The following table summarizes the Company's average daily oil, NGL, gas and total production by asset area during 2017:

	Oil (Bbls)	NGLs (Bbls)	Gas (Mcf) (a)	Total (BOE)
Permian Basin	147,641	44,099	194,904	224,224
South Texas—Eagle Ford Shale	7,754	7,141	44,039	22,235
Raton Basin	—	—	88,497	14,750
West Panhandle	1,669	3,490	7,484	6,407
South Texas—Other	1,502	277	17,531	4,700
Other	5	1	52	14
Total	158,571	55,008	352,507	272,330

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

The following table summarizes the Company's costs incurred by asset area during 2017:

	Property Acquisition Costs		Exploration Costs	Development Costs	Asset Retirement Obligations	Total
	Proved	Unproved				
	(in millions)					
Permian Basin	$ 8	$ 128	$ 1,950	$ 579	$ (17)	$ 2,648
South Texas—Eagle Ford Shale	—	—	74	37	(4)	107
Raton Basin	—	—	1	6	5	12
West Panhandle	—	—	2	10	(4)	8
South Texas—Other	—	—	—	15	3	18
Other	—	—	4	—	—	4
Total	$ 8	$ 128	$ 2,031	$ 647	$ (17)	$ 2,797

Permian Basin. In November 2016, the U.S. Geological Survey ("USGS") announced, based on its estimates, that the Wolfcamp shale in the Permian Basin is the largest continuous oil field in the United States. Pioneer is the largest acreage holder in the Spraberry/Wolfcamp field, with approximately 750,000 gross acres (660,000 net acres). Pioneer's interests in the northern portion of the play comprise approximately 550,000 gross acres and its interests in the southern portion of the play, where the Company has a joint venture with Sinochem, comprise approximately 200,000 gross acres. The oil produced from the Spraberry/Wolfcamp field 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 seven formations, the upper and lower Spraberry, the Jo Mill, the Dean, the Wolfcamp, the Strawn and the Atoka, at depths ranging from 7,500 feet to 14,000 feet. The Company believes that it has significant resource potential within its Spraberry and Wolfcamp formation 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 2017, the Company successfully completed 183 horizontal wells in the northern portion of the play and 40 horizontal wells in the southern portion of the play. In the northern portion of the play, approximately 50 percent of the horizontal wells placed on production were Wolfcamp B interval wells, approximately 35 percent were Wolfcamp A interval wells and approximately 15 percent were Lower Spraberry Shale interval wells. The majority of the wells placed on production in the southern portion of the play were Wolfcamp B interval wells. In addition, during 2017, the Company completed acreage trades that allow the Company to drill wells with longer laterals, improving the expected returns of the wells. The Company estimates that the acreage trades completed in 2017 added approximately 7.2 million lateral feet to the Company's drilling inventory.

The Company plans to operate 20 rigs in the Spraberry/Wolfcamp field in 2018, with 16 rigs operating in the northern portion of the play and four rigs operating in the southern portion of the play. During 2018, the Company expects to place on production between 250 and 275 horizontal wells (200 to 225 horizontal wells in the northern portion of the play and approximately 50 horizontal wells in the southern portion of the play). Approximately 60 percent of the horizontal wells are planned to be drilled in the Wolfcamp B interval, 25 percent in the Wolfcamp A interval and the remaining 15 percent will be a combination of wells in the Spraberry Shale intervals (Jo Mill, Lower Spraberry and Middle Spraberry) and a limited appraisal program for the Clearfork and Wolfcamp D intervals. The Company's 2018 appraisal program includes appraising: (i) its first Clearfork horizontal well (located in Midland County), (ii) seven wells in the Jo Mill and Middle Spraberry intervals in conjunction with nine Lower Spraberry Shale wells to determine an optimal development strategy for the Spraberry formation (these appraisals will test different spacing, staggering, sequencing, and completion design) and (iii) three Wolfcamp D interval wells.

The Company expects to spend $2.6 billion in the Spraberry/Wolfcamp field during 2018, including $2.0 billion of horizontal drilling and completion capital, $300 million for tank battery and disposal facilities, $170 million for gas processing facilities and $110 million for land, science and other costs.

The Company continues to utilize its integrated services to control well costs and operating costs in addition to supporting the execution of its drilling and production activities in the Spraberry/Wolfcamp field. The majority of 2018 drilling activities will be supported by seven of the Company's eight pressure pumping fleets. The Company also owns other field service equipment that supports its drilling and production operations, including pulling units, fracture stimulation tanks, water transport trucks, hot oilers, blowout preventers, construction equipment and fishing tools. The 2018 capital budget includes $78 million for upgrades and maintenance to the Company's pressure pumping and well service equipment.

The Company's sand mine in Brady, Texas, which is strategically located within close proximity (approximately190 miles) of the Spraberry/Wolfcamp field, provides a secure sand source for the Company's horizontal drilling program. In addition, Pioneer has signed a contract for its initial offtake of sand sourced in West Texas where significant new sand supplies are expected to be available in 2018. The Company is evaluating additional contracts for lower cost sand sourced in West Texas. As a result of the expected supply growth of West Texas sand, the planned expansion of the Company’s sand mine at Brady, Texas has been deferred.

In addition to the efficiencies from the Company's integrated services, the Company has been and continues to pursue initiatives to improve drilling and completion efficiencies and reduce costs. The Company's long-term growth plan continues to focus on optimizing the development of the field and addressing the future requirements for water sourcing and disposal, field infrastructure, gas processing, pipeline takeaway capacity for its products, oilfield services, tubulars, electricity, buildings and roads.

The Company is constructing a field-wide water distribution system to reduce the cost of water for drilling and completion activities and to secure adequate supplies of non-potable water to support the Company's long-term growth plan for the Spraberry/Wolfcamp field. Over the past few years, the Company has expanded its mainline system, subsystems and frac ponds to efficiently deliver water to many of Pioneer's drilling locations. The Company is purchasing approximately 120 thousand barrels per day of effluent water from the City of Odessa and has signed an agreement with the City of Midland to upgrade the City's wastewater treatment plant in return for a dedicated long-term supply of water from the plant. Once the Midland plant upgrade is complete, the Company expects to receive approximately two billion barrels of low-cost, non-potable water over a 28-year contract period (up to 240 thousand barrels per day) to support its completion operations. During 2018, the Company expects to spend approximately $135 million to begin the Midland plant upgrade construction and build additional subsystems, frac ponds and produced water reuse facilities.

South Texas Eagle Ford Shale. During 2017, the Company operated two rigs in the Eagle Ford Shale area and drilled 11 new Eagle Ford Shale wells. The objective of this drilling program was to test longer laterals with wider spacing and higher intensity completions in the new wells. The Company's 2017 completions included 25 wells in South Texas, comprising 11 new Eagle Ford Shale wells and nine wells that were drilled but not completed in 2016, as well as five oil wells in the Wilcox formation that were drilled and placed on production during 2017.

See Note Q 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 South Texas assets.

Raton Basin. The Raton Basin properties are located in the southeast portion of Colorado. The Company owns approximately 180,000 gross acres (165,000 net acres) in the center of the Raton Basin and produces coal bed methane gas from the coal seams in the Vermejo and Raton formations from approximately 2,200 wells.

See Note Q 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 Raton Basin assets.

West Panhandle. 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 1,400 Btu and is produced from approximately 700 wells on approximately 240,000 gross and net acres covering approximately 375 square miles.

See Note Q 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 West Panhandle assets.

See Note D of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the impairment charges recorded during 2017, 2016 and 2015 to reduce the carrying value of the Company's properties in the Raton, West Panhandle, South Texas - Eagle Ford Shale and South Texas - Other fields.

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, 2017, 2016 and 2015. 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 decline in oil and 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.

PIONEER NATURAL RESOURCES COMPANY

The following tables set forth production, price and cost data with respect to the Company's properties for 2017, 2016 and 2015. These amounts represent the Company's historical results of 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.

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA

	Year Ended December 31, 2017			
	Spraberry/ Wolfcamp Field	Eagle Ford Shale Field	Raton Field	Total Company Fields
Production information:				
Annual sales volumes:				
Oil (MBbls)	53,889	2,830	—	57,878
NGLs (MBbls)	16,096	2,607	—	20,078
Gas (MMcf)	71,140	16,074	32,302	128,665
Total (MBOE)	81,842	8,116	5,384	99,401
Average daily sales volumes:				
Oil (Bbls)	147,641	7,754	—	158,571
NGLs (Bbls)	44,099	7,141	—	55,008
Gas (Mcf)	194,904	44,039	88,497	352,507
Total (BOE)	224,224	22,235	14,750	272,330
Average prices:				
Oil (per Bbl)	$ 48.32	$ 47.78	$ —	$ 48.24
NGL (per Bbl)	$ 18.69	$ 19.39	$ —	$ 19.31
Gas (per Mcf)	$ 2.45	$ 3.06	$ 2.74	$ 2.63
Revenue (per BOE)	$ 37.62	$ 28.95	$ 16.47	$ 35.39
Average costs (per BOE):				
Production costs:				
Lease operating	$ 4.36	$ 4.56	$ 5.92	$ 4.58
Third-party transportation charges	0.19	6.26	2.21	0.85
Net natural gas plant/gathering	(0.63)	(0.03)	2.03	(0.28)
Workover	0.87	0.56	0.47	0.80
Total	$ 4.79	$ 11.35	$ 10.63	$ 5.95
Production and ad valorem taxes:				
Ad valorem	$ 0.58	$ 0.41	$ 0.54	$ 0.57
Production	1.81	0.72	0.15	1.59
Total	$ 2.39	$ 1.13	$ 0.69	$ 2.16
Depletion expense	$ 15.34	$ 8.79	$ 2.44	$ 13.61

PRODUCTION, PRICE AND COST DATA - (continued)

	Year Ended December 31, 2016			
	Spraberry/ Wolfcamp Field	Eagle Ford Shale Field	Raton Field	Total Company Fields
Production information:				
Annual sales volumes:				
Oil (MBbls)	43,049	4,418	—	48,926
NGLs (MBbls)	10,886	3,755	—	15,922
Gas (MMcf)	51,528	26,133	35,368	124,428
Total (MBOE)	62,523	12,528	5,895	85,586
Average daily sales volumes:				
Oil (Bbls)	117,619	12,070	—	133,677
NGLs (Bbls)	29,743	10,260	—	43,504
Gas (Mcf)	140,788	71,402	96,634	339,966
Total (BOE)	170,827	34,231	16,106	233,842
Average prices:				
Oil (per Bbl)	$ 40.30	$ 35.60	$ —	$ 39.65
NGL (per Bbl)	$ 13.48	$ 12.86	$ —	$ 13.49
Gas (per Mcf)	$ 2.11	$ 2.36	$ 1.87	$ 2.11
Revenue (per BOE)	$ 31.84	$ 21.32	$ 11.25	$ 28.25
Average costs (per BOE):				
Production costs:				
Lease operating	$ 5.35	$ 2.87	$ 5.07	$ 5.02
Third-party transportation charges	0.20	6.81	2.93	1.41
Net natural gas plant/gathering	(0.43)	(0.04)	1.96	0.01
Workover	0.35	0.40	0.32	0.35
Total	$ 5.47	$ 10.04	$ 10.28	$ 6.79
Production and ad valorem taxes:				
Ad valorem	$ 0.50	$ 0.31	$ 0.07	$ 0.46
Production	1.44	0.36	0.01	1.14
Total	$ 1.94	$ 0.67	$ 0.08	$ 1.60
Depletion expense	$ 19.62	$ 12.61	$ 5.42	$ 16.77

PIONEER NATURAL RESOURCES COMPANY

PRODUCTION, PRICE AND COST DATA - (continued)

	Year Ended December 31, 2015			
	Spraberry/ Wolfcamp Field	Eagle Ford Shale Field	Raton Field	Total Company Fields
Production information:				
Annual sales volumes:				
Oil (MBbls)	30,312	6,450	—	38,452
NGLs (MBbls)	8,507	4,230	—	14,086
Gas (MMcf)	41,577	35,220	40,761	131,642
Total (MBOE)	45,748	16,550	6,794	74,478
Average daily sales volumes:				
Oil (Bbls)	83,046	17,670	—	105,347
NGLs (Bbls)	23,306	11,590	—	38,592
Gas (Mcf)	113,909	96,492	111,675	360,662
Total (BOE)	125,336	45,343	18,613	204,050
Average prices:				
Oil (per Bbl)	$ 44.30	$ 41.74	$ —	$ 43.55
NGL (per Bbl)	$ 12.95	$ 13.90	$ —	$ 13.31
Gas (per Mcf)	$ 2.29	$ 2.69	$ 2.22	$ 2.40
Revenue (per BOE)	$ 33.84	$ 25.55	$ 13.30	$ 29.25
Average costs (per BOE):				
Production costs:				
Lease operating	$ 9.08	$ 3.21	$ 6.04	$ 7.24
Third-party transportation charges	0.26	4.90	3.12	1.60
Net natural gas plant/gathering	(0.45)	0.02	1.82	0.16
Workover	0.61	0.99	—	0.62
Total	$ 9.50	$ 9.12	$ 10.98	$ 9.62
Production and ad valorem taxes:				
Ad valorem	$ 0.92	$ 0.50	$ 0.27	$ 0.76
Production (a)	1.62	0.65	(0.01)	1.19
Total	$ 2.54	$ 1.15	$ 0.26	$ 1.95
Depletion expense	$ 22.12	$ 15.80	$ 5.19	$ 18.01

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(a) The credit amount in production taxes per BOE for the Raton field is due to the receipt of a severance tax refund from the state of Colorado.

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, 2017:

PRODUCTIVE WELLS

Gross Productive Wells			Net Productive Wells		
Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**
6,905	3,679	10,584	6,146	3,150	9,296

Leasehold acreage. The following table sets forth information about the Company's developed, undeveloped and royalty leasehold acreage as of December 31, 2017:

LEASEHOLD ACREAGE

Developed Acreage		Undeveloped Acreage		
Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**	**Royalty Acreage**
1,315,707	1,132,711	111,627	104,894	241,133

The following table sets forth the expiration dates of the leases on the Company's gross and net undeveloped acres as of December 31, 2017:

	Acres Expiring (a)	
	Gross	**Net**
2018	87,718	84,683
2019	8,031	6,630
2020	1,950	1,320
2021	1,487	1,072
2022	—	—
Thereafter	12,441	11,189
Total	111,627	104,894

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

Of the 91,313 net acres expiring in 2018 and 2019, 60,485 net acres (66 percent) are concentrated in eastern Colorado. Over the past few years, the Company has conducted limited exploratory activities across this acreage. The Company's exploratory drilling activities have not resulted in discovering commercial quantities of hydrocarbons; therefore, no proved reserves have been attributed to any of this acreage. The remainder of the net undeveloped acres expiring over the next two year period is primarily concentrated in the Permian Basin in West Texas, where the Company has an active drilling program and ongoing efforts to extend leases that may not be drilled prior to expiration. The Company currently has no proved undeveloped reserve locations scheduled to be drilled after lease expiration.

Drilling and other exploratory and development activities. The following table sets forth the number of gross and net wells drilled by the Company during 2017, 2016 and 2015 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			Net Wells		
	Year Ended December 31,			Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
Productive wells:						
Development	26	39	116	20	32	78
Exploratory	222	215	218	198	194	151
Dry holes:						
Development	—	—	—	—	—	—
Exploratory	2	—	2	1	—	1
Total	250	254	336	219	226	230
Success ratio (a)	99%	100%	99%	99%	100%	99%

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

Present activities. The following table sets forth information about the Company's wells that were in process of being drilled as of December 31, 2017:

	Gross Wells	Net Wells
Development	14	12
Exploratory	136	123
Total	150	135

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 these 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.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of the date of this Report regarding the Company's executive officers. All of the Company's executive officers serve at the discretion of the Company's board of directors. There are no family relationships among any of the Company's directors or executive officers.

Name	Position	Age
Timothy L. Dove	President and Chief Executive Officer	61
Mark S. Berg	Executive Vice President, Corporate/Vertically Integrated Operations	59
Chris J. Cheatwood	Executive Vice President and Chief Technology Officer	57
Richard P. Dealy	Executive Vice President and Chief Financial Officer	51
J.D. Hall	Executive Vice President, Permian Operations	52
Kenneth H. Sheffield, Jr.	Executive Vice President, Operations/Engineering/Facilities	57
William F. Hannes	Senior Vice President, Special Projects	58
Frank E. Hopkins	Senior Vice President, Investor Relations	69
Mark H. Kleinman	Senior Vice President and General Counsel	56
Teresa A. Fairbrook	Vice President and Chief Human Resources Officer	44
Margaret M. Montemayor	Vice President and Chief Accounting Officer	40
Stephanie D. Stewart	Vice President and Chief Information Officer	49

Timothy L. Dove

Mr. Dove has served as the Company's President and Chief Executive Officer since January 1, 2017. He held the positions for the Company of President and Chief Operating Officer from December 2004 to January 2017, Executive Vice President and Chief Financial Officer from February 2000 to November 2004 and Executive Vice President - Business Development from August 1997 to January 2000. Mr. Dove also served as President and Chief Operating Officer of the general partner of Pioneer Southwest Energy Partners L.P. ("Pioneer Southwest") from June 2007 through the Company's acquisition of Pioneer Southwest in December 2013. Mr. Dove joined Parker & Parsley in 1994 as a Vice President and was promoted to Senior Vice President - Business Development in October 1996, in which position he served until the Company's formation in August 1997. Before joining Parker & Parsley, Mr. Dove was employed with Diamond Shamrock Corp and its successor, Maxus Energy Corp., in various capacities in international exploration and production, marketing, refining, and planning and development. Mr. Dove earned a Bachelor of Science degree in Mechanical Engineering from Massachusetts Institute of Technology and received his Master of Business Administration from the University of Chicago.

Mark S. Berg

Mr. Berg was elected the Company's Executive Vice President and General Counsel in April 2005, serving in those capacities until January 2014, at which time he assumed broader executive responsibilities, most recently being elected to serve as Executive Vice President, Corporate/Vertically Integrated Operations in May 2017. Mr. Berg had previously served as Executive Vice President, Corporate/Operations since August 2015 and Executive Vice President and General Counsel of the general partner of Pioneer Southwest from June 2007 through the Company's acquisition of Pioneer Southwest in December 2013. Prior to joining the Company, Mr. Berg served as Executive Vice President, General Counsel and Secretary of American General Corporation, a Fortune 200 diversified financial services company, from 1997 through 2002. Subsequent to the sale of American General to American International Group, Inc., Mr. Berg joined Hanover Compressor Company as Senior Vice President, General Counsel and Secretary. He served in that capacity from May 2002 through April 2004. Mr. Berg began his career in 1983 with the Houston-based law firm of Vinson & Elkins L.L.P. He was a partner with the firm from 1990 through 1997. Mr. Berg graduated Magna Cum Laude and Phi Beta Kappa with a Bachelor of Arts degree from Tulane University in 1980. He earned his Juris Doctorate with honors from the University of Texas School of Law in 1983.

Chris J. Cheatwood

Mr. Cheatwood was elected the Company's Executive Vice President and Chief Technology Officer in May 2017. Mr. Cheatwood had previously served the Company as Executive Vice President, Business Development and Geoscience since November 2011, Executive Vice President, Business Development and Technology from February 2010 until November 2011, Executive Vice President, Geoscience from November 2007 until February 2010, Executive Vice President - Worldwide Exploration from January 2002 until November 2007, Senior Vice President - Worldwide Exploration from December 2000 to January 2002 and Vice President - Domestic Exploration from July 1998 to December 2000. Mr. Cheatwood also served as an Executive Vice President of the general partner of Pioneer Southwest from June 2007 through the Company's acquisition of Pioneer Southwest in December 2013. Before joining the Company, Mr. Cheatwood spent ten years with Exxon Corporation. Mr. Cheatwood is a graduate of the University of Oklahoma with a Bachelor of Science degree in Geology and earned his Master of Science degree in Geology from the University of Tulsa.

Richard P. Dealy

Mr. Dealy was elected the Company's Executive Vice President and Chief Financial Officer in November 2004. Mr. Dealy held positions for the Company as Vice President and Chief Accounting Officer from February 1998 to November 2004 and Vice President and Controller from August 1997 to January 1998. Mr. Dealy also served as Executive Vice President, Chief Financial Officer, Treasurer and Director of the general partner of Pioneer Southwest from June 2007 through the Company's acquisition of Pioneer Southwest in December 2013. Mr. Dealy joined Parker & Parsley in July 1992 and was promoted to Vice President and Controller in 1996, in which position he served until August 1997. He is a Certified Public Accountant, and before joining Parker & Parsley, he was employed by KPMG LLP. Mr. Dealy graduated with honors from Eastern New Mexico University with a Bachelor of Business Administration degree in Accounting and Finance and is a Certified Public Accountant.

J. D. Hall

Mr. Hall was elected Executive Vice President, Permian Operations, in August 2015. Mr. Hall had previously held positions for the Company as Executive Vice President, Southern Wolfcamp Operations from August 2014 to August 2015, Senior Vice President, South Texas Operations from June 2013 to August 2014, Vice President, South Texas Operations from February 2013 to June 2013, Vice President, South Texas Asset Team from September 2012 to February 2013 and Vice President, Eagle Ford Asset Team from January 2010 to September 2012. Prior to his positions in South Texas, he was the Operations Manager in Alaska from January 2005 to January 2010. He previously held several other positions with the Company, including managing offshore, onshore and international projects. He began his career with a predecessor company, MESA, Inc. ("MESA"), in 1989. He has a Bachelor of Science degree in Mechanical Engineering from Texas Tech University and is a Registered Professional Engineer in Texas.

Kenneth H. Sheffield, Jr.

Mr. Sheffield was elected as Executive Vice President, Operations/Engineering/Facilities in May 2017. Mr. Sheffield has previously served the Company in a number of executive positions, including Executive Vice President, STAT (the Company's South Texas Asset Team), WAT (the Company's Western Asset Team) and Corporate Engineering from August 2015 to May 2017, Executive Vice President, South Texas Operations from August 2014 to August 2015, Senior Vice President, Operations and Engineering from June 2013 to August 2014, Vice President, Corporate Engineering from November 2011 to June 2013 and President of the Company's Alaska subsidiary from September 2002 to November 2011. Mr. Sheffield joined MESA in June 1982 and held a number of supervisory and technical positions with MESA in the areas of drilling, production, reservoir engineering and acquisitions until being promoted to Vice President Acquisitions & Development in 1996. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

William F. Hannes

Mr. Hannes was elected the Company's Senior Vice President, Special Projects in January 2017. Mr. Hannes had previously served the Company as Senior Vice President, Special Management Committee Advisor since August 2014, Executive Vice President, Southern Wolfcamp Operations from February 2013 until August 2014, Executive Vice President, South Texas Operations from February 2010 until February 2013, Executive Vice President, Business Development from December 2007 until February 2010, Executive Vice President, Worldwide Business Development from November 2005 until December 2007 and Vice President, Engineering and Development from September 2003 until November 2005. Mr. Hannes joined Parker & Parsley in July 1997 as Director of Business Development, and continued to serve the Company in this capacity after the Company's formation in August 1997 until he was promoted to Vice President - Engineering and Development in June 2001, which position he held until November 2005. Prior to joining Parker & Parsley, Mr. Hannes held engineering positions with Mobil Corporation and Superior Oil Company. Mr. Hannes earned his Bachelor of Science degree in Petroleum Engineering from Texas A&M University.

Frank E. Hopkins

Mr. Hopkins was elected the Company's Senior Vice President, Investor Relations in August 2011. Mr. Hopkins had previously held the position of Vice President, Investor Relations since joining the Company in February 2005. Before joining the Company, Mr. Hopkins was with Exxon Mobil Corporation where he served as General Manager, Strategic Planning for the Global Services Company, and as Deputy Manager, Investor Relations. He also served in various capacities with Mobil Corporation, including Manager, Investor Relations and Assistant Controller. Mr. Hopkins earned his Bachelor of Science degree in Business

Administration from Penn State University and also participated in the executive education program at the Kellogg School of Management of Northwestern University.

Mark H. Kleinman

Mr. Kleinman was elected Senior Vice President and General Counsel in January 2014. He also held the positions of Corporate Secretary from June 2005 through August 2015, Vice President from May 2006 until January 2014 and Chief Compliance Officer from June 2005 until May 2013. Mr. Kleinman also served as Vice President and Secretary of the general partner of Pioneer Southwest from June 2007 until April 2008 and as its Vice President and Chief Compliance Officer from April 2008 through the Company's acquisition of Pioneer Southwest in December 2013. Mr. Kleinman earned a Bachelor of Arts degree in Government from the University of Texas and graduated, with honors, from the University of Texas School of Law.

Teresa A. Fairbrook

Ms. Fairbrook was elected the Company's Vice President and Chief Human Resources Officer in March 2016, prior to which she had served as Vice President, Human Resources since February 2013. She joined the Company in 1999, serving in a number of positions in the Human Resources Department. Prior to joining the Company, Ms. Fairbrook was in human resources at Dal-Tile Corporation in Dallas, Texas, where she held a variety of roles in employee relations, recruiting and benefits. Ms. Fairbrook received a Bachelor of Business Administration degree from St. Mary's University in San Antonio, Texas, with an emphasis in Human Resource Management, and is a Certified Compensation Professional.

Margaret M. Montemayor

Ms. Montemayor was elected the Company's Vice President and Chief Accounting Officer in March 2014. Ms. Montemayor had previously served the Company as Vice President and Corporate Controller since January 2014, Corporate Controller from April 2012 to December 2013 and Director of Technical Accounting and Financial Reporting from June 2010 to March 2012. Prior to joining the Company, Ms. Montemayor served as Manager at PricewaterhouseCoopers LLP since June 2006. Ms. Montemayor graduated from St. Mary's University in San Antonio, Texas with a Bachelor of Business Administration degree in Accounting and a Master of Business Administration and is a Certified Public Accountant.

Stephanie D. Stewart

Ms. Stewart joined the Company in June 2014 as Vice President and Chief Information Officer. Before joining the Company, she served as Vice President of E&P Data and Analytics at Devon Energy at the end of her 12-year tenure there. Prior to Devon, she worked in information technology at Williams Energy and BP Amoco. Ms. Stewart earned a Bachelor of Business Administration degree from the University of Oklahoma and her Executive MBA in Energy from the University of Oklahoma's Price College of Business.

Officers are generally elected by the Company's board of directors at its meeting on the day of each annual election of directors, with each such officer serving until a successor has been elected and qualified.

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, 2017 and 2016. 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. In February 2018, the Board (i) declared a cash dividend of $0.16 per share on Pioneer's outstanding common stock, payable April 12, 2018 to stockholders of record at the close of business on March 29, 2018 and (ii) approved a common stock repurchase program to offset the impact of dilution associated with annual employee stock awards. The stock repurchase program allows for up to $100 million of common stock to be repurchased during 2018.

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, 2017 and 2016:

	High	Low	Dividends Declared Per Share
Year ended December 31, 2017			
Fourth quarter	$ 174.59	$ 140.31	$ —
Third quarter	$ 166.29	$ 125.46	$ 0.04
Second quarter	$ 192.93	$ 153.42	$ —
First quarter	$ 199.83	$ 168.13	$ 0.04
Year ended December 31, 2016			
Fourth quarter	$ 195.00	$ 166.50	$ —
Third quarter	$ 190.94	$ 147.21	$ 0.04
Second quarter	$ 171.88	$ 136.97	$ —
First quarter	$ 145.87	$ 103.50	$ 0.04

On February 14, 2018, the last reported sales price of the Company's common stock, as reported in the NYSE composite transactions, was $179.50 per share.

As of February 14, 2018, the Company's common stock was held by 10,633 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, 2017.

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Amount of Shares that May Yet Be Purchased under Plans or Programs
October 2017	—	$ —	—	—
November 2017	—	$ —	—	—
December 2017	174	$ 156.58	—	—
Total	174	$ 156.58	—	$ —

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

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, 2017 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,				
	2017	2016	2015	2014	2013
	(in millions, except per share data)				
Statements of Operations Data:					
Oil and gas revenues	$ 3,518	$ 2,418	$ 2,178	$ 3,599	$ 3,088
Total revenues and other income (a)	$ 5,455	$ 3,382	$ 4,561	$ 4,954	$ 3,658
Total costs and expenses (a)(b)	$ 5,146	$ 4,341	$ 4,982	$ 3,357	$ 4,232
Income (loss) from continuing operations	$ 833	$ (556)	$ (266)	$ 1,041	$ (361)
Loss from discontinued operations, net of tax (c)	$ —	$ —	$ (7)	$ (111)	$ (438)
Net income (loss) attributable to common stockholders	$ 833	$ (556)	$ (273)	$ 930	$ (838)
Income (loss) from continuing operations attributable to common stockholders per share:					
Basic	$ 4.86	$ (3.34)	$ (1.79)	$ 7.17	$ (2.94)
Diluted	$ 4.85	$ (3.34)	$ (1.79)	$ 7.15	$ (2.94)
Net income (loss) attributable to common stockholders per share:					
Basic	$ 4.86	$ (3.34)	$ (1.83)	$ 6.40	$ (6.16)
Diluted	$ 4.85	$ (3.34)	$ (1.83)	$ 6.38	$ (6.16)
Dividends declared per share	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Balance Sheet Data (as of December 31):					
Total assets	$ 17,003	$ 16,459	$ 15,154	$ 14,909	$ 12,272
Long-term obligations	$ 3,596	$ 4,482	$ 5,317	$ 4,901	$ 4,426
Total equity	$ 11,279	$ 10,411	$ 8,375	$ 8,589	$ 6,615

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(a) Includes revisions to present certain of the Company's purchased oil and gas and sales of purchased oil and gas on a net basis within purchased oil and gas expense. See Note B of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for more information about the revision of the Company's revenues and expenses associated with these transactions.

(b) During 2017, 2016, 2015 and 2013, the Company recognized impairment charges of $285 million related to dry gas properties in the Raton field, $32 million related to oil and gas properties in the West Panhandle field, $1.1 billion related to oil and gas properties in the West Panhandle, South Texas - Other and South Texas - Eagle Ford Shale fields and $1.5 billion related to dry gas properties in the Raton field, 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.

(c) The Company recognized impairment charges of (i) $305 million attributable to its Hugoton assets, its Barnett Shale assets and Pioneer Alaska in 2014 and (ii) $729 million attributable to its Barnett Shale assets and Pioneer Alaska in 2013. The results of these operations are classified as discontinued operations in accordance with GAAP.

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

Financial and Operating Performance

Pioneer's financial and operating performance for 2017 included the following highlights:

- Net income attributable to common stockholders was $833 million ($4.85 per diluted share) for the year ended December 31, 2017, as compared to a net loss of $556 million ($3.34 per diluted share) in 2016. The primary components of the $1,389 million increase in earnings attributable to common stockholders include:
  - a $1.1 billion increase in oil and gas revenues as a result a 25 percent increase in average realized commodity prices per BOE, combined with a 16 percent increase in sales volumes;
  - a $206 million increase in net gains on disposition of assets, primarily due to recognizing a gain of $194 million on the sale of approximately 20,500 acres in the Martin County region of the Permian Basin during 2017;
  - a $121 million increase in the Company's income tax benefit, primarily as a result of a reduction in deferred tax liabilities related to the reduction in the federal corporate income tax rate beginning in 2018;
  - an $80 million decrease in DD&A expense, primarily attributable to (i) commodity price increases and the Company's cost reduction initiatives, both of which had the effect of adding proved reserves by lengthening the economic lives of the Company's producing wells and (ii) additions to proved reserves attributable to the Company's successful Spraberry/Wolfcamp horizontal drilling program;
  - a $61 million decrease in net derivative losses, primarily as a result of changes in forward commodity prices, the cash settlement of derivative positions in accordance with their terms and changes in the Company's portfolio of derivatives;
  - a $54 million decrease in interest expense, primarily due to the repayment of both the Company's 6.65% senior notes, which matured in March 2017, and the Company's 5.875% senior notes, which matured in July 2016;
  - a $44 million decrease in other expense, primarily related to reductions in idle drilling and well service equipment charges and net losses from Company-provided fracture stimulation and related service operations that are provided to third party working interest owners, partially offset by an increase in unused firm transportation costs;
  - a $33 million decrease in losses associated with purchases and sales of oil and gas used to fulfill transportation commitments;
  - a $21 million increase in interest and other income, primarily due to interest received from the Company's short-term and long-term investments and severance tax refunds; and
  - a $13 million decrease in exploration and abandonment charges, primarily due to writing off the Company's unproved acreage in Alaska during 2016 when it was determined that it was no longer expected to be developed; partially offset by
  - a $253 million increase in impairment charges, principally related to the impairment charge recorded in 2017 to reduce the carrying value of the Company's Raton field; and
  - an $89 million increase in total oil and gas production costs and production and ad valorem taxes as of a result of the aforementioned increases in commodity prices and sales volumes.
- During 2017, average daily sales volumes increased on a BOE basis by 16 percent to 272,330 BOEPD, as compared to 233,842 BOEPD during 2016, primarily due to the Company's successful Spraberry/Wolfcamp horizontal drilling program.
- Average oil, NGL and gas prices increased during 2017 to $48.24 per Bbl, $19.31 per Bbl and $2.63 per Mcf, respectively, as compared to $39.65 per Bbl, $13.49 per Bbl and $2.11 per Mcf, respectively in 2016.
- Net cash provided by operating activities increased by 39 percent to $2.1 billion for 2017, as compared to $1.5 billion during 2016, primarily due to increases in the Company's oil and gas revenues in 2017 as a result of increases in commodity prices and sales volumes, partially offset by a $613 million reduction in cash provided by commodity derivatives.

First Quarter 2018 Outlook

Based on current estimates, the Company expects the following operating and financial results for the quarter ending March 31, 2018:

Production is forecasted to average 304,000 to 314,000 BOEPD.

Production costs (including production and ad valorem taxes and transportation costs) are expected to average $7.00 to $9.00 per BOE, based on current NYMEX strip commodity prices. DD&A expense is expected to average $12.50 to $14.50 per BOE.

Total exploration and abandonment expense is expected to be $20 million to $30 million. General and administrative expense is expected to be $80 million to $85 million. Interest expense is expected to be $33 million to $38 million, and other expense is expected to be $60 million to $70 million, including $45 million to $55 million of charges associated with excess firm gathering and transportation commitments. Accretion of discount on asset retirement obligations is expected to be $4 million to $7 million.

The Company's effective income tax rate is expected to range from 21 percent to 25 percent, reflecting the lower federal corporate income tax rate enacted by the Tax Cuts and Jobs Act. Cash income taxes are expected to be less than $5 million.

2018 Capital Budget

Pioneer's capital budget for 2018 totals $2.9 billion, consisting of $2.6 billion for drilling and completion related activities, including additional tank batteries, saltwater disposal facilities and gas processing facilities, and $260 million for water infrastructure, vertical integration, field facilities and vehicles. The 2018 capital budget excludes acquisitions, asset retirement obligations, capitalized interest, geological and geophysical general and administrative expense and information technology system upgrades.

The 2018 drilling and completion capital of $2.6 billion is focused on oil drilling, with approximately 99 percent of the capital allocated to horizontal drilling activities in the Spraberry/Wolfcamp field. The following is the forecasted spending by asset area:

- Spraberry/Wolfcamp field - $2.6 billion, including (i) $2.0 billion of horizontal drilling capital, (ii) $300 million for infrastructure (additional tank batteries and saltwater disposal facilities), (iii) $170 million for gas processing facilities and (iv) $110 million of land, science and other expenditures; and
- Other assets - $20 million.

The 2018 capital budget is expected to be funded from a combination of operating cash flow, cash and cash equivalents on hand, sales of short-term and long-term investments and, if necessary, proceeds from planned asset divestitures or borrowings under the Company's credit facility.

Acquisitions

During 2017, 2016 and 2015, the Company spent $136 million, $446 million and $36 million, respectively, to acquire primarily undeveloped acreage for future exploitation and exploration activities in the Spraberry/Wolfcamp field of the Permian Basin. During 2016, the Company completed the acquisition of approximately 28,000 net acres in the Permian Basin, with net production of approximately 1,400 BOEPD, from an unaffiliated third party for $428 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

In February 2018, the Company announced its intention to divest its properties in South Texas, Raton and the West Panhandle field and focus its efforts and capital resources to its Permian Basin assets. No assurance can be given that the sales will be completed in accordance with the Company's plans or on terms and at prices acceptable to the Company.

In April 2017, the Company completed the sale of approximately 20,500 acres in the Martin County region of the Permian Basin, with net production of approximately1,500 BOEPD, to an unaffiliated third party for cash proceeds of $264 million. The sale resulted in a gain of $194 million. In conjunction with the divestiture, the Company reduced the carrying value of goodwill by $2 million, reflecting the portion of the Company's goodwill related to the assets sold.

In July 2015, the Company completed the sale of its 50.1 percent equity interest in EFS Midstream to an unaffiliated third party, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing and the remaining $501 million was received in July 2016. The Company recorded a net gain on the disposition of $777 million in September 2015.

See Notes C, D and Q of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information about the Company's divestitures in 2017 and 2015 and it's planned divestitures of South Texas, Raton and the West Panhandle field.

Results of Operations

Oil and gas revenues. Oil and gas revenues totaled $3.5 billion, $2.4 billion and $2.2 billion during 2017, 2016 and 2015, respectively.

The increase in 2017 oil and gas revenues relative to 2016 is primarily due to increases of 19 percent, 26 percent and 4 percent in oil, NGL and gas sales volumes, respectively, and increases of 22 percent, 43 percent and 25 percent in oil, NGL and gas prices, respectively.

The increase in 2016 oil and gas revenues relative to 2015 is primarily due to increases of 27 percent and 13 percent in oil and NGL sales volumes, respectively, partially offset by a six percent decline in gas sales volumes and declines of nine percent and 12 percent in oil and gas prices, respectively.

Average daily sales volumes in 2017 and 2016 increased by 16 percent and 15 percent, respectively, as compared to the average daily sales volumes in the respective prior years, principally due to the Company's successful Spraberry/Wolfcamp horizontal drilling program.

The following table provides average daily sales volumes from continuing operations for 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	**2016**	**2015**
Oil (Bbls)	158,571	133,677	105,347
NGLs (Bbls)	55,008	43,504	38,592
Gas (Mcf) (a)	352,507	339,966	360,662
Total (BOE)	272,330	233,842	204,050

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

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 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	**2016**	**2015**
Oil (per Bbl)	$ 48.24	$ 39.65	$ 43.55
NGLs (per Bbl)	$ 19.31	$ 13.49	$ 13.31
Gas (per Mcf)	$ 2.63	$ 2.11	$ 2.40
Total (per BOE)	$ 35.39	$ 28.25	$ 29.25

Sales of purchased oil and gas. The Company periodically enters into pipeline capacity commitments in order to secure available oil, NGL and gas transportation capacity from the Company's areas of production. The Company enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's WTI oil sales to a Gulf Coast or international export market price and to satisfy unused pipeline capacity commitments. Revenues and expenses from these transactions are presented on a gross basis as the Company acts as a principal in the transaction by assuming both the risk and rewards of ownership, including credit risk, of the commodities purchased and the responsibility to deliver the commodities sold. The transportation costs associated with these transactions are presented on a net basis in purchased oil and gas expense. The net effect of third party purchases and sales of oil and gas for the year ended December 31, 2017 was a loss of $31 million, as compared to a loss of $64 million and a loss of $39 million for the years ended December 31, 2016 and 2015, respectively. Firm transportation 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 unused transportation commitment charges.

Interest and other income. The Company's interest and other income was $53 million for the year ended December 31, 2017, as compared to $32 million and $22 million for the years ended December 31, 2016 and 2015, respectively. The increase in interest and other income during 2017 as compared to 2016 was primarily due to (i) an increase of $11 million in severance, sales and property tax refunds and (ii) an increase of $10 million in interest income on short-term and long-term investments. The increase in interest and other income during 2016 as compared to 2015 was primarily due to (i) an increase of $19 million in interest income on short-term and long-term investments, partially offset by (ii) a decrease of $5 million in equity interest in income of EFS Midstream. 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 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. During the year ended December 31, 2017, the Company recorded $100 million of net derivative losses, compared to $161 million of net derivative losses and $879 million of net derivative gains for the years ended December 31, 2016 and 2015, respectively, on commodity price, diesel price, interest rate and marketing derivatives. For the years ended December 31, 2017, 2016 and 2015, the Company received net cash receipts of $74 million, $690 million and $876 million, respectively, from its derivative activities.

The following table details the net cash receipts on the Company's commodity derivatives and the relative price impact (per Bbl or Mcf) for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,					
	2017		2016		2015	
	Net cash receipts (payments) (in millions)	Price impact	Net cash receipts (in millions)	Price impact	Net cash receipts (in millions)	Price impact
Oil derivative receipts	$ 67	$ 1.15 per Bbl	$ 609	$ 12.42 per Bbl	$ 744	$ 19.36 per Bbl
NGL derivative receipts (payments)	(1)	$ (0.06) per Bbl	5	$ 0.30 per Bbl	18	$ 0.79 per Bbl
Gas derivative receipts (payments)	2	$ 0.02 per Mcf	67	$ 0.54 per Mcf	114	$ 0.87 per Mcf
Total net commodity derivative receipts	$ 68		$ 681		$ 876	

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 on disposition of assets, net. The Company recorded net gains on the disposition of assets of $208 million, $2 million and $782 million during the years ended December 31, 2017, 2016 and 2015, respectively. For the year ended December 31, 2017, the Company's gain on disposition of assets is primarily due to a gain of $194 million recognized on the sale of approximately 20,500 acres in the Martin County region of the Permian Basin. For the year ended December 31, 2015, the Company's gains on disposition of assets are primarily due to the gain of $777 million recognized on the sale of EFS Midstream. 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 net gains on disposition of assets.

Oil and gas production costs. The Company recognized oil and gas production costs from continuing operations of $591 million, $581 million and $717 million for the years ended December 31, 2017, 2016 and 2015, respectively. 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.

The following table provides the components of the Company's total production costs per BOE for 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
Lease operating expenses	$ 4.58	$ 5.02	$ 7.24
Third party transportation charges	0.85	1.41	1.60
Net natural gas plant (income) charges	(0.28)	0.01	0.16
Workover costs	0.80	0.35	0.62
Total production costs	$ 5.95	$ 6.79	$ 9.62

Total oil and gas production costs per BOE for the year ended December 31, 2017 decreased 12 percent as compared to 2016. The decrease in lease operating expenses per BOE is primarily due to a greater proportion of the Company's production coming from horizontal wells in the Spraberry/Wolfcamp area that have lower per BOE lease operating costs and the Company's cost reduction initiatives. The decrease in third party transportation costs per BOE is due to a lower proportion of the Company's total production being subject to higher Eagle Ford Shale transportation costs. The net natural gas plant income per BOE is primarily reflective of increased earnings on third party volumes that are processed in the Company-owned facilities due to higher NGL and gas prices. The increase in workover costs per BOE was primarily due to an increase in Permian vertical well workover activity due to the improvement in commodity prices.

Total oil and gas production costs per BOE for the year ended December 31, 2016 decreased 29 percent as compared to 2015. The decrease in lease operating expenses per BOE is also primarily due to a greater proportion of the Company's production coming from horizontal wells in the Spraberry/Wolfcamp area that have lower per BOE lease operating costs, cost reduction initiatives and lower electricity and fuel costs, which are impacted by lower commodity prices. The decline in workover costs per BOE was primarily due to reduced workover activity on the older vertical wells, as such activity was generally uneconomical as a result of the lower commodity price environment.

Production and ad valorem taxes. The Company recorded production and ad valorem taxes of $215 million during 2017, as compared to $136 million and $145 million for 2016 and 2015, 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. The increase in production and ad valorem taxes per BOE for the year ended December 31, 2017 as compared to 2016, is primarily due to the increase in commodity prices during 2017 and, for ad valorem tax purposes, the higher valuation attributable to the Company's successful Spraberry/Wolfcamp horizontal drilling program in 2017. The decrease in production and ad valorem taxes per BOE for the year ended December 31, 2016 as compared to 2015 is primarily due to the decrease in commodity prices during 2016.

The following table provides the Company's production and ad valorem taxes per BOE for 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
Production taxes	$ 1.59	$ 1.14	$ 1.19
Ad valorem taxes	0.57	0.46	0.76
Total ad valorem and production taxes	$ 2.16	$ 1.60	$ 1.95

Depletion, depreciation and amortization expense. The Company's total DD&A expense was $1.4 billion ($14.08 per BOE), $1.5 billion ($17.29 per BOE), and $1.4 billion ($18.59 per BOE) for 2017, 2016 and 2015, respectively. Depletion expense on oil and gas properties, the largest component of DD&A expense, was $13.61, $16.77 and $18.01 per BOE during 2017, 2016 and 2015, respectively.

Depletion expense on oil and gas properties for the year ended December 31, 2017 decreased 19 percent as compared to 2016. The decrease is primarily due to (i) additions to proved reserves attributable to the Company's successful Spraberry/Wolfcamp horizontal drilling program and (ii) commodity price increases and cost reduction initiatives, both of which had the effect of adding proved reserves by lengthening the economic lives of the Company's producing wells.

Depletion expense on oil and gas properties was $16.77 during 2016, as compared to $18.01 during 2015. The seven percent decrease in per BOE depletion expense, as compared to that of 2015 was primarily due to (i) reserve additions attributable to the Company's successful drilling activities and (ii) cost reduction initiatives that lowered expected lease operating expense, which had the effect of adding reserves by lengthening the economic life of the Company's producing wells.

Impairment of oil and gas properties and other long-lived assets. The Company recorded impairment expense to reduce the carrying values of oil and gas properties by $285 million, $32 million and $1.1 billion during the years ended December 31, 2017, 2016 and 2015.

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) proved reserves and risk-adjusted probable and possible reserves, (ii) commodity prices, (iii) production costs, (iv) capital expenditures and (v) production. Management's long-term commodity price outlooks are developed based on third party longer-term commodity futures price outlooks as of a measurement date ("Management's Price Outlooks").

As a result of the Company's impairment assessments, the Company recognized pretax, noncash impairment charges to reduce the carrying values of (i) the Raton field ($285 million) during the year ended December 31, 2017, (ii) the West Panhandle field ($32 million) during the year ended December 31, 2016 and (iii) the Eagle Ford Shale field ($846 million), the West Panhandle field ($138 million) and the South Texas - Other field ($72 million) during the year ended December 31, 2015.

It is reasonably possible that the Company's estimate of undiscounted future net cash flows may change in the future resulting in the need to impair the carrying values of its properties. The primary factors that may affect estimates of future cash flows are (i) future reserve adjustments, both positive and negative, to proved reserves and risk-adjusted probable and possible reserves (ii) results of future drilling activities, (iii) changes in 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.

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 for 2017, 2016 and 2015 (in millions):

	Year Ended December 31,		
	2017	**2016**	**2015**
Geological and geophysical	$ 84	$ 77	$ 71
Exploratory well costs	10	1	17
Leasehold abandonments and other	12	41	11
	$ 106	$ 119	$ 99

During 2017, the Company's exploration and abandonment expense was primarily attributable to $84 million of geological and geophysical costs, of which $66 million was geological and geophysical administrative costs, $10 million associated with unsuccessful exploration wells and $12 million of leasehold abandonment expense and other. During 2017, the Company completed and evaluated 224 exploration/extension wells, 99 percent of which were successfully completed as discoveries.

During 2016, the Company's exploration and abandonment expense was primarily attributable to $77 million of geological and geophysical costs, of which $70 million was geological and geophysical administrative costs, and $41 million of leasehold abandonment expense, which included $32 million associated with unproved acreage in Alaska in which the Company held an overriding royalty interest. During 2016, the Company completed and evaluated 215 exploration/extension wells, all of which were successfully completed as discoveries.

During 2015, the Company's exploration and abandonment expense was primarily attributable to $71 million of geological and geophysical costs, of which $60 million was geological and geophysical administrative costs; $17 million of unsuccessful exploration wells, primarily related to drilling activities attributable to the Company's unproved acreage position in southeast Colorado; and $11 million of leasehold abandonment expense, which includes $7 million associated with the Company's unproved acreage position in southeast Colorado. During 2015, the Company completed and evaluated 220 exploration/extension wells, 218 of which were successfully completed as discoveries.

General and administrative expense. General and administrative expense totaled $326 million ($3.28 per BOE), $325 million ($3.80 per BOE) and $327 million ($4.39 per BOE) during 2017, 2016 and 2015, respectively. The 2017 and 2016 decreases in general and administrative expense per BOE were primarily due to an increase in sales volumes of 16 percent and 15 percent, respectively, combined with the Company's cost reduction initiatives, including not replacing personnel who have left the Company and reduced contractor activity.

Accretion of discount on asset retirement obligations. Accretion of discount on asset retirement obligations was $19 million, $18 million and $12 million during the years ended December 31, 2017, 2016 and 2015, respectively. 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 $153 million, $207 million and $187 million during 2017, 2016 and 2015, respectively. The decrease in interest expense during the year ended December 31, 2017, as compared 2016, was primarily due to the repayment of both the Company's 6.65% Senior Notes, which matured in March 2017, and the Company's 5.875% Senior Notes, which matured in July 2016. The increase in interest expense during the year ended December 31, 2016, as compared to 2015, was primarily due to incremental interest expense associated with the Company's December 2015 issuance of $500 million of 3.45% Senior Notes due 2021 and $500 million of 4.45% Senior Notes due 2026. The weighted average interest rate on the Company's indebtedness for the year ended December 31, 2017 was 5.6 percent, as compared to 6.0 percent and 6.9 percent for the years ended December 31, 2016 and 2015, respectively.

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 expense. Other expense was $244 million during 2017, as compared to $288 million during 2016 and $315 million during 2015. The $44 million decrease in other expense during 2017, as compared to 2016, was primarily due to (i) a decrease of $64 million in idle drilling and well service equipment charges and (ii) a decrease of $37 million in net losses from Company-provided fracture stimulation and related service operations that are provided to third party working interest owners, partially offset by (iii) an increase of $58 million in unused firm transportation costs.

The $27 million decrease in other expense during 2016, as compared to 2015, was primarily due to decreases of (i) $78 million in inventory and other property and equipment impairment charges, (ii) $28 million in idle drilling and well service equipment charges and (iii) $19 million in restructuring charges (see further information below), partially offset by increases of (iv) $56 million in unused firm transportation costs and (v) $20 million in net losses from Company-provided fracture stimulation and related service operations that are provided to third party working interest owners.

In February 2016, the Company announced plans to restructure its pressure pumping operations in South Texas, including relocating its two Eagle Ford Shale pressure pumping fleets to the Spraberry/Wolfcamp area. In connection therewith, the Company offered severance to certain employees and relocated a number of other employees from its South Texas locations to its operations in the Permian Basin. The initiative was substantially complete as of December 31, 2016. In connection therewith, the Company recognized $4 million of restructuring charges during the year ended December 31, 2016. The restructuring costs included $3 million in cash employee severance costs and $1 million in employee relocation and other costs.

In May 2015, the Company announced plans to restructure its operations in Colorado, including closing its office in Denver, Colorado and eliminating its Trinidad-based pressure pumping services operations. The restructuring plan was substantially complete as of December 31, 2015. In connection therewith, the Company recognized $23 million of restructuring charges during the year ended December 31, 2015, which includes approximately $17 million in employee severance costs and $6 million in office lease-related costs.

The Company expects to continue to incur charges associated with excess firm gathering and transportation commitments and vertical integration operations until commodity prices improve, allowing the Company to increase its drilling activities, or, in the case of gathering and transportation commitments, the contractual obligations expire.

See Notes B, J and 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 benefit. The Company recognized an income tax benefit attributable to earnings from continuing operations of $524 million during 2017, as compared to an income tax benefit of $403 million and $155 million during 2016 and 2015, respectively. The Company's effective tax rate on earnings from continuing operations, excluding income from noncontrolling interest, for 2017 was a negative 170 percent for 2017 and 42 percent and 37 percent for 2016 and 2015, respectively, as compared to the combined United States federal and state statutory rates of approximately 36 percent.

The Company's effective tax rate for 2017 differs from the combined statutory rate primarily due to the enactment on December 22, 2017 of the Tax Cuts and Jobs Act (the "Tax Reform Legislation"), which made significant changes to the United States federal income tax law. The most significant change affecting the Company was a reduction in the federal corporate income tax rate to 21 percent beginning January 1, 2018. This rate change resulted in a $625 million income tax benefit during 2017, primarily associated with the remeasurement of the Company's deferred tax liabilities at the new corporate tax rate as of December 31, 2017. Excluding the effects of the Tax Reform Legislation, the Company's effective tax rate for 2017 would have been 33 percent.

The effective rate for 2016 differs from the combined statutory rate primarily due to recognizing research and experimental expenditures credits of $72 million during 2016 and, to a lesser extent, state income tax apportionments and nondeductible expenses.

The Tax Reform Legislation also repealed corporate alternative minimum tax ("AMT") for tax years beginning in January 1, 2018, and provides that existing AMT credit carryovers are refundable beginning in 2018. As of December 31, 2017, the Company had AMT credit carryovers of $20 million that are expected to be fully refunded by 2022.

The Tax Reform Legislation preserves the deductibility of intangible drilling costs and provides for 100 percent bonus depreciation on personal tangible property expenditures through 2022. The bonus depreciation percentage is phased down from 100 percent beginning in 2023 through 2026.

The Tax Reform Legislation is a comprehensive bill containing other provisions, such as limitations on the deductibility of interest expense and certain executive compensation, that are not expected to materially affect Pioneer. The ultimate impact of the Tax Reform Legislation may differ from the Company's estimates as of December 31, 2017 due to changes in the interpretations and assumptions made by the Company as well as additional regulatory guidance that may be issued.

As of December 31, 2017 and 2016, the Company had unrecognized tax benefits of $124 million and $112 million, respectively, resulting from research and experimental expenditures related to horizontal drilling and completion innovations. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recognized. The Company expects to substantially resolve the uncertainties associated with the unrecognized tax benefits by December 2018.

See 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 tax attributes.

Loss from discontinued operations, net of tax. In 2015, the Company recognized losses from discontinued operations, net of tax, of $7 million related to plugging and abandonment obligations associated with two Gulf of Mexico wells that Pioneer divested in 2009. The results of operations for these assets were recorded in discontinued operations upon their divestiture and therefore the costs incurred subsequent to their divestiture are reflected as discontinued operations in the 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 regarding the Company's discontinued operations .

Capital Commitments, Capital Resources and Liquidity

Capital commitments. The Company's primary needs for cash are for (i) capital expenditures, (ii) acquisitions of oil and gas properties, vertical integration assets and facilities, (iii) payments of contractual obligations, including debt maturities, (iv) dividends and share repurchases and (v) 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, sales of short-term and long-term investments, proceeds from divestitures or external financing sources as discussed in "Capital resources" below. During 2018, 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, sales of short-term and long-term investments and, if necessary, availability under the Company's credit facility, or proceeds from divestitures of nonstrategic assets. Although the Company expects that these sources of funding will be adequate to fund capital expenditures, dividend payments and provide adequate liquidity to fund other needs, including repayment of the May 2018 debt maturity and 2018 stock repurchaces, no assurances can be given that such funding sources will be adequate to meet the Company's future needs.

During 2018, the Company plans to focus its capital spending primarily on oil drilling activities in the Spraberry/Wolfcamp area of the Permian Basin. The Company's 2018 capital budget totals $2.9 billion (excluding acquisitions, asset retirement obligations, capitalized interest, geological and geophysical administrative costs and information technology systems upgrades), consisting of $2.6 billion for drilling and completion related activities, including additional tank batteries, saltwater disposal facilities and gas processing facilities, and $260 million for water infrastructure, vertical integration, field facilities and vehicles. Based on the Company's current Management Price Outlooks, Pioneer expects its net cash flows from operating activities, cash and cash equivalents on hand, sales of short-term and long-term investments and, if necessary, availability under the Company's credit facility or proceeds from divestitures of nonstrategic assets to be sufficient to fund its planned capital expenditures, dividend payments and provide adequate liquidity to fund other needs.

Investing activities. Net cash used in investing activities during 2017 was $1.8 billion, as compared to net cash used in investing activities of $3.8 billion and $1.8 billion during 2016 and 2015, respectively. The decrease in net cash flow used in investing activities during 2017, as compared to 2016, is primarily due to (i) a decrease of $1.8 billion in net purchases of investments (commercial paper, corporate bonds and time deposits), (ii) a $563 million increase in proceeds from investments and (iii) the purchase of 28,000 net acres in the Permian Basin, with net production of approximately 1,400 BOEPD, from an unaffiliated third party for $428 million in 2016, partially offset by (iv) a $508 million increase in additions to oil and gas properties, (v) a $155 million decrease in proceeds from the disposition of assets and (v) a $133 million increase in additions to other assets and other property and equipment. Proceeds from the disposition of assets during 2017 included $264 million associated with the sale of approximately 20,500 acres in the Martin County region of the Permian Basin with net production of approximately1,500 BOEPD. Proceeds from the disposition of assets during 2016 included $501 million associated with the sale of EFS Midstream. The Company's investing activities during the year ended December 31, 2017 were primarily funded by net cash provided by operating activities.

The increase in net cash flow used in investing activities during 2016, as compared to 2015, is primarily due to (i) net purchases of $1.8 billion of investments (commercial paper, corporate bonds and time deposits), (ii) the purchase of the aforementioned 28,000 net acres in the Permian Basin from an unaffiliated third party for $428 million in 2016 and (iii) a $46 million decrease in proceeds from the disposition of assets, partially offset by (iv) a $253 million decrease in additions to oil and gas properties and (v) an $80 million decrease in additions to other assets and other property and equipment. Proceeds from the disposition of assets during 2016 and 2015 included $501 million and $530 million, respectively, associated with the sale of EFS Midstream. The Company's investing activities during the year ended December 31, 2016 were primarily funded by net cash provided by operating activities, cash on hand and the Company's issuance of 19.8 million shares of common stock during 2016 for cash proceeds of $2.5 billion.

Dividends/distributions. During each of the years ended December 31, 2017, 2016 and 2015, the Board declared semiannual dividends of $0.04 per common share. Associated therewith, the Company paid $14 million, $13 million and $12 million, respectively, of aggregate dividends. In addition, in February 2018, the Board declared a cash dividend of $0.16 per share on Pioneer's outstanding common stock, payable April 12, 2018 to stockholders of record at the close of business on March 29, 2018. 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 that time.

Off-balance sheet arrangements. From time to time, the Company enters into arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2017, the material off-balance sheet arrangements and transactions that the Company had entered into included (i) operating lease agreements, (ii) drilling commitments, (iii) firm purchase, transportation and fractionation commitments, (iv) open purchase commitments and (v) contractual obligations for which the ultimate settlement amounts are not fixed and determinable. The contractual obligations for which the ultimate settlement amounts are not fixed and determinable include (i) derivative contracts that are sensitive to future changes in commodity prices or interest rates, (ii) gathering, processing (primarily treating and fractionation) and transportation commitments on uncertain volumes of future throughput, (iii) open purchase commitments and (iv) 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. The Company expects to enter into similar contractual arrangements in the future, including incremental derivative contracts and additional firm purchase and transportation arrangements, in order to support the Company's business plans. 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 (primarily related to commitments to pay day rates for contracted drilling rigs), capital funding obligations, derivative obligations, firm transportation and fractionation commitments, minimum annual gathering, processing and transportation commitments and other liabilities (including postretirement benefit obligations). 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, 2017:

	Payments Due by Year			
	2018	2019 and 2020	2021 and 2022	Thereafter
	(in millions)			
Long-term debt (a)	$ 450	$ 450	$ 1,100	$ 750
Operating leases (b)	27	95	77	680
Drilling commitments (c)	93	78	—	—
Derivative obligations (d)	232	23	—	—
Purchase commitments (e)	179	6	—	—
Other liabilities (f)	102	82	82	169
Firm purchase, gathering, processing, transportation and fractionation commitments (g)	568	1,291	1,103	1,554
	$ 1,651	$ 2,025	$ 2,362	$ 3,153

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(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, 2017. 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 drilling commitments.

(d) Derivative obligations represent net liabilities determined in accordance with master netting arrangements for commodity derivatives that were valued as of December 31, 2017. The Company's commodity derivative contracts are periodically measured and recorded at fair value and continue to be subject to market and credit risk. The ultimate liquidation value of the Company's commodity derivatives will be dependent upon actual future commodity prices, which may differ materially from the inputs used to determine the derivatives' fair values as of December 31, 2017. 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, 2017.

(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) Firm purchase, gathering, processing, transportation and fractionation commitments represent take-or-pay agreements, which include (i) contractual commitments to purchase sand and water for use in the Company's drilling operations and (ii) estimated fees on production throughput commitments and demand fees associated with volume delivery commitments. The Company does not expect to be able to fulfill all of its short-term and long-term volume 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 any 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 firm purchase, gathering, processing, transportation and fractionation commitments.

Capital resources. The Company's primary capital resources are cash and cash equivalents, net cash provided by operating activities, sales of short-term and long-term investments, proceeds from divestitures and proceeds from financing activities (principally borrowings under the Company's credit facility or issuances of debt or equity securities). If internal cash flows 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 (i) by using cash on hand, (ii) through sales of short-term and long-term investments, (iii) with borrowings under the Company's credit facility, (iv) through issuances of debt or equity securities or (v) through other sources, such as sales of nonstrategic assets.

Operating activities. Net cash provided by operating activities for the years ended December 31, 2017, 2016 and 2015 was $2.1 billion, $1.5 billion and $1.3 billion, respectively. The increase in net cash flow provided by operating activities in 2017, as compared to 2016, was primarily due to increases in the Company's oil and gas revenues in 2017 as a result of increases in commodity prices and sales volumes, partially offset by a $613 million reduction in cash provided by commodity derivatives during 2017. The increase in net cash flow provided by operating activities in 2016, as compared to 2015, was primarily due to increases in the Company's oil and gas revenues in 2016 as a result of increased sales volumes (partially offset by decreases in oil and gas prices), reductions in operating costs and a decrease in funds used to satisfy working capital obligations.

Asset divestitures. In February 2018, the Company announced its intention to divest its properties in South Texas, Raton and the West Panhandle field and focus its efforts and capital resources to its Permian Basin assets. No assurance can be given that the sales will be completed in accordance with the Company's plans or on terms and at prices acceptable to the Company.

In April 2017, the Company completed the sale of approximately 20,500 acres in the Martin County region of the Permian Basin to an unaffiliated third party for cash proceeds of $264 million. The sale resulted in a gain of $194 million. In conjunction with the divestiture, the Company reduced the carrying value of goodwill by $2 million, reflecting the portion of the Company's goodwill related to the assets sold.

In July 2015, the Company completed the sale of its 50.1 percent interest in EFS Midstream to an unaffiliated third party, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing and the remaining $501 million was received in July 2016.

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 asset divestitures.

Financing activities. Net cash used in financing activities during 2017 was $529 million, as compared to net cash provided by financing activities during 2016 and 2015 of $2.0 billion and $951 million, respectively. The following provides a description of the Company's significant financing activities during 2017, 2016 and 2015:

- During March 2017, the Company repaid $485 million associated with the maturity of the Company's 6.65% senior notes;
- During July 2016, the Company repaid $455 million associated with the maturity of the Company's 5.875% senior notes;
- During June 2016, the Company completed the sale of 6.0 million shares of its common stock at a per-share price, after underwriter discounts and offering expenses, of $155.27, resulting in $937 million of net cash proceeds;
- During January 2016, the Company completed the sale of 13.8 million shares of its common stock at a per-share price, after underwriter discounts and offering expenses, of $115.78, resulting in $1.6 billion of net cash proceeds;
- During December 2015, the Company issued $500 million of 3.45% Senior Notes due 2021 and $500 million of 4.45% Senior Notes due 2026 and received combined proceeds, net of $9 million of underwriter discounts and offering expenses, of $991 million; and
- During August 2015, the Company amended its credit facility with a syndicate of financial institutions to extend its maturity to August 2020, while maintaining aggregate loan commitments of $1.5 billion.

See Note G of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding the significant debt 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, net cash provided by operating activities, sales of short-term and long-term investments, proceeds from divestitures and unused borrowing capacity under its credit facility. As of December 31, 2017, the Company had no outstanding borrowings under its 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 .60:1, which is above the Company's December 31, 2017 ratio of .16:1. The Company also had cash on hand of $896 million, short-term investments of $1.2 billion and long-term investments of $66 million as of December 31, 2017. If internal cash flows do not meet the Company's expectations, the Company may fund a portion of its capital expenditures using cash on hand, through sales of short-term and long-term investments, availability under its credit facility, issuances of debt or equity securities or other sources, such as sales of nonstrategic assets, and/or reduce its level of capital expenditures or reduce dividend payments. 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, sales of short-term and long-term investments and, if necessary, available capacity under the Company's credit facility will be adequate to fund 2018 capital expenditures, dividend payments and provide adequate liquidity to fund other needs, including repayment of the May 2018 debt maturity and 2018 stock repurchases, 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 mid-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: (i) production growth opportunities, (ii) liquidity, (iii) debt levels, (iv) asset composition and (v) 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 impact the Company's ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. The Company's net book capitalization at December 31, 2017 was $11.8 billion, consisting of cash and cash equivalents of $896 million, short-term and long-term investments of $1.3 billion, debt of $2.7 billion and equity of $11.3 billion. The Company's net debt to book capitalization increased to five percent at December 31, 2017 from two percent at December 31, 2016, primarily due to funding the Company's oil and gas drilling and other property investments with cash and cash equivalents and sales of short-term and long-term investments. The Company's ratio of current assets to current liabilities decreased to 1.41:1 at December 31, 2017, as compared to 2.11:1 at December 31, 2016, primarily due to an increase in accounts payable as a result of the Company's higher drilling and completion related activities in the fourth quarter of 2017.

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 2017, 2016 and 2015, the Company recognized exploration, abandonment, geological and geophysical expense of $106 million, $119 million and $99 million, respectively.

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, 2017, 2016 and 2015 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, 2017 is the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the Company based the 2017 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, 2017, the Company carried unproved property costs of $558 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; and
(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration 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 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.

Uncertain tax positions. The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. As of December 31, 2017 and 2016, the Company had unrecognized tax benefits of $124 million and $112 million, respectively, resulting from research and experimental expenditures related to horizontal drilling and completion innovations. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recognized. See Note O of Notes to the Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding uncertain tax positions.

Goodwill impairment. The Company reviews its goodwill for impairment at least annually. During the third quarters of 2017 and 2016, the Company performed a qualitative assessment of goodwill to assess 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. The Company determined that it was more likely than not that the Company's goodwill was not impaired. 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 (i) the Black-Scholes option pricing model to measure the fair value of stock options, (ii) the closing stock price on the day prior to the date of grant for the fair value of restricted stock awards, (iii) the closing stock price on the balance sheet date for restricted stock awards that are expected to be settled wholly or partially in cash on their vesting date and (iv) the Monte Carlo simulation method for the fair value of performance unit awards. 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 measures and records at fair value on a recurring basis include trading securities, commodity derivative contracts and interest rate contracts. Other assets are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances. The assets and liabilities that the Company measures and records at fair value on a nonrecurring basis include inventory, proved and unproved oil and gas properties, assets acquired and liabilities assumed in business combinations and other long-lived assets that are written down to fair value when they are impaired or held for sale. The Company also measures and discloses certain financial assets and liabilities at fair value, such as long-term debt and investments. The valuation methods used by the Company to measure the fair values of these assets and liabilities may 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."

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, 2017, 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, 2017, the Company was a party to swap contracts, collar contracts and 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 2017:

	Derivative Contract Net Liabilities		
	Commodities	Interest Rate	Total
	(in millions)		
Fair value of contracts outstanding as of December 31, 2016	$ (76)	$ 6	$ (70)
Changes in contract fair values	(99)	(1)	(100)
Contract maturities	(67)	—	(67)
Contract termination receipts	(2)	(5)	(7)
Fair value of contracts outstanding as of December 31, 2017	$ (244)	$ —	$ (244)

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, 2017 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, 2017. Although the Company had no outstanding variable rate debt as of December 31, 2017, the average variable contractual rates for its credit facility (that matures in August 2020) projected forward proportionate to the forward yield curve for LIBOR on February 14, 2018 is presented in the table below.

INTEREST RATE SENSITIVITY
DEBT OBLIGATIONS AS OF DECEMBER 31, 2017

	Year Ending December 31,							Asset (Liability) Fair Value at December 31,
	2018	2019	2020	2021	2022	Thereafter	Total	2017
				(dollars in millions)				
Total Debt:								
Fixed rate principal maturities (a)	$ 450	$ —	$ 450	$ 500	$ 600	$ 750	$ 2,750	$ (2,936)
Weighted average fixed interest rate	5.11%	5.00%	4.42%	4.72%	4.94%	5.70%		
Average variable interest rate	3.50%	3.94%	4.13%					

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(a) Represents maturities of principal amounts excluding debt issuance costs and debt issuance discounts.

Interest rate swaps. During 2017, the Company was party to interest rate derivative contracts whereby the Company would have received the three-month LIBOR rate for the 10-year period from December 2017 through December 2027 in exchange for paying a fixed interest rate of 1.81 percent on a notional amount of $100 million on December 15, 2017. During the fourth quarter of 2017, the Company liquidated its interest rate derivative contracts for cash proceeds of $5 million. As of December 31, 2017, the Company did not have any interest rate derivatives outstanding.

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 oil, NGL and gas prices as of December 31, 2017. Although mitigated by the Company's derivative activities, declines in oil, NGL and gas prices would reduce the Company's revenues.

The Company manages commodity price risk with derivative contracts, such as swap contracts, 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") 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 long put-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 for 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.

DERIVATIVE FINANCIAL INSTRUMENTS AS OF DECEMBER 31, 2017

	2018					
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ending December 31, 2019	Asset (Liability) Fair Value at December 31, 2017 (a)
						(in millions)
Oil Derivatives:						
Average daily notional Bbl volumes:						
Collar contracts	3,000	3,000	3,000	3,000	—	$ (4)
Weighted average ceiling price per Bbl	$ 58.05	$ 58.05	$ 58.05	$ 58.05	$ —	
Weighted average floor price per Bbl	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ —	
Collar contracts with short puts (b)	149,000	149,000	154,000	159,000	40,000	$ (234)
Weighted average ceiling price per Bbl	$ 57.79	$ 57.79	$ 57.70	$ 57.62	$ 59.62	
Weighted average floor price per Bbl	$ 47.42	$ 47.42	$ 47.34	$ 47.26	$ 52.00	
Weighted average short put price per Bbl	$ 37.38	$ 37.38	$ 37.31	$ 37.23	$ 42.00	
Average forward NYMEX oil prices (c)	$ 60.60	$ 60.23	$ 59.00	$ 57.65	$ 55.13	
NGL Derivatives:						
Ethane basis swap contracts (MMBtu) (d)	6,920	6,920	6,920	6,920	6,920	$ —
Weighted average price differential per MMBtu	$ 1.60	$ 1.60	$ 1.60	$ 1.60	$ 1.60	
Average forward NYMEX gas prices (c)	$ 2.59	$ 2.66	$ 2.74	$ 2.83	$ 2.77	
Gas Derivatives:						
Average daily notional MMBtu volumes:						
Swap contracts (e)	30,000	100,000	100,000	100,000	—	$ 6
Weighted average fixed price per MMBtu	$ 3.37	$ 3.00	$ 3.00	$ 3.00	$ —	
Collar contracts with short puts	100,000	50,000	50,000	50,000	—	$ 4
Weighted average ceiling price per MMBtu	$ 3.82	$ 3.40	$ 3.40	$ 3.40	$ —	
Weighted average floor price per MMBtu	$ 3.15	$ 2.75	$ 2.75	$ 2.75	$ —	
Weighted average short put price per MMBtu	$ 2.57	$ 2.25	$ 2.25	$ 2.25	$ —	
Average forward NYMEX gas prices (c)	$ 2.59	$ 2.66	$ 2.74	$ 2.83		
Basis swap contracts						
Southern California index swap contracts (f)(g)	80,000	40,000	80,000	53,261	80,000	$ (12)
Weighted average fixed price per MMBtu	$ 0.34	$ 0.30	$ 0.30	$ 0.43	$ 0.31	
Average forward basis differential prices (h)	$ 0.40	$ 0.39	$ 0.58	$ 0.70	$ 0.61	
Houston Ship Channel index swap volume (f)(i)	3,444	—	—	—	—	$ —
Weighted average fixed price per MMBtu	$ 0.63	$ —	$ —	$ —	$ —	
Average forward basis differential prices (h)	$ 0.64	$ —	$ —	$ —		

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(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, 2017, the Company entered into additional oil collar contracts with short puts for 25,000 Bbls per day of 2019 production with a ceiling price of $62.55 per Bbl, a floor price of $53.80 per Bbl and a short put price of $43.80 per Bbl.

(c) The average forward NYMEX oil, ethane and gas prices are based on February 14, 2018 market quotes.

(d) The ethane basis swap contracts reduce the price volatility of ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices. The ethane basis swap contracts fix the basis differential on a NYMEX Henry Hub ("HH") MMBtu equivalent basis. The Company will receive the HH price plus the price differential on 6,920 MMBtu per day, which is equivalent to 2,500 Bbls per day of ethane.

(e) Subsequent to December 31, 2017, the Company entered into additional swap contracts for 100,000 MMBtu per day of February 2018 production with a price of $3.46 per MMBtu.
(f) The referenced basis swap contracts fix the basis differentials between Permian Basin index prices and southern California or Houston Ship Channel index prices for Permian Basin gas forecasted for sale in southern California or the Gulf Coast region.
(g) Subsequent to December 31, 2017, the Company entered into additional basis swap contracts for 20,000 MMBtu per day of November 2018 through March 2019 production with a price differential of $0.77 per MMBtu.
(h) The average forward basis differential prices are based on February 14, 2018 market quotes for basis differentials between Permian Basin index prices and southern California and Houston Ship Channel index prices.
(i) Subsequent to December 31, 2017, the Company entered into additional basis swap contracts for 10,000 MMBtu per day of February 2018 production with a price differential of $0.82 per MMBtu.

Marketing derivatives. Periodically, 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 swap contracts to mitigate price risk. The following table provides information about the Company's marketing derivative financial instruments that were sensitive to changes in oil prices as of December 31, 2017:

	2018				Liability Fair Value at December 31, 2017 (a)
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	(in millions)
Oil Derivatives:					
Average daily notional Bbl volumes:					
Basis swap contracts					
Louisiana Light Sweet index swap volume (b)	10,000	10,000	6,739	—	$ (3)
Price differential ($/Bbl)	$ 3.18	$ 3.18	$ 3.18	$ —	
Average forward basis differential prices (c)	$ 2.51	$ 2.15	$ 2.25		
Magellan East Houston index swap volume (b)	11,556	11,703	3,370	—	$ (1)
Price differential ($/Bbl)	$ 3.29	$ 3.30	$ 3.30	$ —	
Average forward basis differential prices (c)	$ 3.50	$ 3.25	$ 3.70		

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(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) The referenced basis swap contracts fix the basis differentials between NYMEX WTI and Louisiana Light Sweet ("LLS") or Magellan East Houston ("MEH") oil prices for Permian Basin oil forecasted for sale in the Gulf Coast region.
(c) The average forward basis differential prices are based on February 14, 2018 market quotes for basis differentials between NYMEX WTI and LLS or MEH oil prices.

Diesel derivatives. Periodically, the Company enters into diesel derivative swap contracts that mitigate fuel price risk. The diesel derivative swap contracts are priced at an index that is highly correlated to the prices that the Company incurs to fuel its drilling rigs and fracture stimulation fleet equipment. During 2017, the Company liquidated its diesel derivative swap contracts for cash proceeds of $2 million. As of December 31, 2017, the Company did not have any diesel derivative contracts outstanding.

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, 2016 to December 31, 2017.

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 or export market 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Pioneer Natural Resources Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Pioneer Natural Resources Company (the Company) as of December 31, 2017 and 2016, and the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, 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) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated February 20, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1998.
Dallas, Texas
February 20, 2018

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS
(in millions)

	December 31,	
	2017	**2016**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 896	$ 1,118
Short-term investments	1,218	1,441
Accounts receivable:		
Trade, net	639	517
Due from affiliates	1	1
Income taxes receivable	7	3
Inventories	212	181
Derivatives	11	14
Other	26	23
Total current assets	3,010	3,298
Property, plant and equipment, at cost:		
Oil and gas properties, using the successful efforts method of accounting:		
Proved properties	20,404	18,566
Unproved properties	558	486
Accumulated depletion, depreciation and amortization	(9,196)	(8,211)
Total property, plant and equipment	11,766	10,841
Long-term investments	66	420
Goodwill	270	272
Other property and equipment, net	1,759	1,529
Other assets, net	132	99
	$ 17,003	$ 16,459

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED BALANCE SHEETS (continued)
(in millions, except share data)

	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable:		
Trade	$ 1,174	$ 741
Due to affiliates	108	134
Interest payable	59	68
Current portion of long-term debt	449	485
Derivatives	232	77
Other	106	61
Total current liabilities	2,128	1,566
Long-term debt	2,283	2,728
Derivatives	23	7
Deferred income taxes	899	1,397
Other liabilities	391	350
Equity:		
Common stock, $.01 par value; 500,000,000 shares authorized; 173,796,743 and 173,221,845 shares issued as of December 31, 2017 and 2016, respectively	2	2
Additional paid-in capital	8,974	8,892
Treasury stock, at cost; 3,608,132 and 3,497,742 shares as of December 31, 2017 and 2016, respectively	(249)	(218)
Retained earnings	2,547	1,728
Total equity attributable to common stockholders	11,274	10,404
Noncontrolling interest in consolidated subsidiaries	5	7
Total equity	11,279	10,411
Commitments and contingencies		
	$ 17,003	$ 16,459

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

PIONEER NATURAL RESOURCES COMPANY

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

	Year Ended December 31,		
	2017	**2016**	**2015**
Revenues and other income:			
Oil and gas	$ 3,518	$ 2,418	$ 2,178
Sales of purchased oil and gas	1,776	1,091	700
Interest and other	53	32	22
Derivative gains (losses), net	(100)	(161)	879
Gain on disposition of assets, net	208	2	782
	5,455	3,382	4,561
Costs and expenses:			
Oil and gas production	591	581	717
Production and ad valorem taxes	215	136	145
Depletion, depreciation and amortization	1,400	1,480	1,385
Purchased oil and gas	1,807	1,155	739
Impairment of oil and gas properties	285	32	1,056
Exploration and abandonments	106	119	99
General and administrative	326	325	327
Accretion of discount on asset retirement obligations	19	18	12
Interest	153	207	187
Other	244	288	315
	5,146	4,341	4,982
Income (loss) from continuing operations before income taxes	309	(959)	(421)
Income tax benefit	524	403	155
Income (loss) from continuing operations	833	(556)	(266)
Loss from discontinued operations, net of tax	—	—	(7)
Net income (loss) attributable to common stockholders	$ 833	$ (556)	$ (273)
Basic net income (loss) per share attributable to common stockholders:			
Income (loss) from continuing operations	$ 4.86	$ (3.34)	$ (1.79)
Loss from discontinued operations	—	—	(0.04)
Net income (loss)	$ 4.86	$ (3.34)	$ (1.83)
Diluted net income (loss) per share attributable to common stockholders:			
Income (loss) from continuing operations	$ 4.85	$ (3.34)	$ (1.79)
Loss from discontinued operations	—	—	(0.04)
Net income (loss)	$ 4.85	$ (3.34)	$ (1.83)
Basic and diluted weighted average shares outstanding	170	166	149

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

PIONEER NATURAL RESOURCES COMPANY

CONSOLIDATED STATEMENTS OF EQUITY
(in millions, except share data and dividends per share)

		Equity Attributable to Common Stockholders					
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Noncontrolling Interests	Total Equity
	(in thousands)						
Balance as of December 31, 2014	148,905	$ 2	$ 6,167	$ (171)	$ 2,583	$ 8	$ 8,589
Dividends declared ($0.08 per share)	—	—	—	—	(12)	—	(12)
Employee stock purchases	58	—	3	3	—	—	6
Purchase of treasury stock	(201)	—	—	(31)	—	—	(31)
Tax benefits related to stock-based compensation	—	—	7	—	—	—	7
Compensation costs:							
Vested compensation awards, net	618	—	—	—	—	—	—
Compensation costs included in net loss	—	—	90	—	—	—	90
Distributions to noncontrolling interests	—	—	—	—	—	(1)	(1)
Net loss	—	—	—	—	(273)	—	(273)
Balance as of December 31, 2015	149,380	$ 2	$ 6,267	$ (199)	$ 2,298	$ 7	$ 8,375
Issuance of common stock	19,838	—	2,534	—	—	—	2,534
Dividends declared ($0.08 per share)	—	—	—	—	(14)	—	(14)
Exercise of long-term incentive plan stock options and employee stock purchases	98	—	1	6	—	—	7
Purchase of treasury stock	(200)	—	—	(25)	—	—	(25)
Tax benefits related to stock-based compensation	—	—	1	—	—	—	1
Compensation costs:							
Vested compensation awards, net	608	—	—	—	—	—	—
Compensation costs included in net loss	—	—	89	—	—	—	89
Net loss	—	—	—	—	(556)	—	(556)
Balance as of December 31, 2016	169,724	$ 2	$ 8,892	$ (218)	$ 1,728	$ 7	$ 10,411

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 millions, except share data and dividends per share)

		Equity Attributable to Common Stockholders					
	Shares Outstanding	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Noncontrolling Interests	Total Equity
	(in thousands)						
Balance as of December 31, 2016	169,724	$ 2	$ 8,892	$ (218)	$ 1,728	$ 7	$ 10,411
Dividends declared ($0.08 per share)	—	—	—	—	(14)	—	(14)
Exercise of long-term incentive plan stock options and employee stock purchases	81	—	1	5	—	—	6
Purchases of treasury stock	(191)	—	—	(36)	—	—	(36)
Compensation costs:							
Vested compensation awards	575	—	—	—	—	—	—
Compensation costs included in net income	—	—	79	—	—	—	79
Purchase of noncontrolling interest	—	—	2	—	—	(2)	—
Net income	—	—	—	—	833	—	833
Balance as of December 31, 2017	170,189	$ 2	$ 8,974	$ (249)	$ 2,547	$ 5	$ 11,279

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 millions)

	Year Ended December 31,		
	2017	2016	2015
Cash flows from operating activities:			
Net income (loss)	$ 833	$ (556)	$ (273)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	1,400	1,480	1,385
Impairment of oil and gas properties	285	32	1,056
Impairment of inventory and other property and equipment	2	8	86
Exploration expenses, including dry holes	22	42	28
Deferred income taxes	(519)	(379)	(178)
Gain on disposition of assets, net	(208)	(2)	(782)
Accretion of discount on asset retirement obligations	19	18	12
Discontinued operations	—	—	(4)
Interest expense	5	13	18
Derivative related activity	174	851	(3)
Amortization of stock-based compensation	79	89	90
Other	74	67	45
Change in operating assets and liabilities			
Accounts receivable	(122)	(134)	54
Income taxes receivable	(4)	40	(20)
Inventories	(35)	(32)	8
Derivatives	—	(24)	—
Investments	8	(22)	—
Other current assets	(3)	(7)	—
Accounts payable	134	58	(258)
Interest payable	(9)	3	25
Other current liabilities	(45)	(46)	(34)
Net cash provided by operating activities	2,090	1,499	1,255
Cash flows from investing activities:			
Proceeds from disposition of assets, net of cash sold	352	507	553
Payments for acquisitions	—	(428)	—
Proceeds from investments	1,465	902	—
Purchase of investments	(899)	(2,741)	—

Additions to oil and gas properties	(2,365)	(1,857)	(2,110)
Additions to other assets and other property and equipment, net	(336)	(203)	(283)
Net cash used in investing activities	(1,783)	(3,820)	(1,840)
Cash flows from financing activities:			
Borrowings of long-term debt	—	—	998
Principal payments on long-term debt	(485)	(455)	—
Proceeds from issuance of common stock, net of issuance costs	—	2,534	—
Distributions to noncontrolling interests	—	—	(1)
Exercise of long-term incentive plan stock options and employee stock purchases	6	7	6
Purchases of treasury stock	(36)	(25)	(31)
Payments of financing fees	—	—	(9)
Dividends paid	(14)	(13)	(12)
Net cash provided by (used in) financing activities	(529)	2,048	951
Net increase (decrease) in cash and cash equivalents	(222)	(273)	366
Cash and cash equivalents, beginning of period	1,118	1,391	1,025
Cash and cash equivalents, end of period	$ 896	$ 1,118	$ 1,391

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017, 2016 and 2015

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 that explores for, develops and produces oil, natural gas liquids ("NGLs") and gas within the United States, with operations primarily in the Permian Basin in West Texas, the Eagle Ford Shale play in South Texas, the Raton field in southeast Colorado and the West Panhandle field in the Texas Panhandle.

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. All material intercompany balances and transactions have been eliminated.

Certain reclassifications have been made to the 2016 and 2015 consolidated financial statement and footnote amounts in order to conform them to the 2017 presentations.

In addition, the presentation of certain purchases and sales of third-party oil and gas with the same counterparty has been revised in 2016 and 2015 to present such transactions on a net basis in purchased oil and gas expense. Previously, these transportation arrangements, which were carried out as purchases from and sales to the same third party, were separately stated on a gross basis in sales of purchased oil and gas and purchased oil and gas expense. 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 2016 and 2015 consolidated 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 total costs and expenses:

	Year Ended December 31,	
	2016	2015
	(in millions)	
Sales of purchased oil and gas, as previously reported	$ 1,533	$ 964
Revision to sales of purchased oil and gas	(442)	(264)
Sales of purchased oil and gas, reported herein	$ 1,091	$ 700
Purchased oil and gas, as previously reported	$ 1,597	$ 1,003
Revision to purchased oil and gas	(442)	(264)
Purchased oil and gas, reported herein	$ 1,155	$ 739

Use of estimates in the preparation of financial statements. Preparation of the accompanying consolidated financial statements in conformity with generally accepted accounting principles in the United States ("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.

Investments. Periodically, the Company invests in commercial paper and corporate bonds with investment grade rated entities. The Company also periodically enters into time deposits with financial institutions. Commercial paper and time deposits are included in cash and cash equivalents if they have maturity dates that are less than 90 days at the date of purchase; otherwise, investments are reflected in short-term investments or long-term investments in the accompanying consolidated balance sheets based on their maturity dates.

Accounts receivable. As of December 31, 2017 and 2016, the Company had accounts receivable – trade, net of allowances for bad debts, of $639 million and $517 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, 2017 and 2016, the Company's allowances for doubtful accounts totaled $1 million for both respective periods. 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 accompanying consolidated balance sheets and as charges to other expense in the accompanying 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, water, 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 allowances for materials and supplies inventories are recorded as reductions to the carrying values of the materials and supplies inventories in the Company's accompanying consolidated balance sheets and as charges to other expense in the accompanying consolidated statements of operations.

Commodity inventories are carried at the lower of cost or market, on a first-in, first-out basis. The Company's commodity inventories consist of oil, NGLs and gas volumes held in storage or as linefill in pipelines. Any valuation allowances of commodity inventories are recorded as reductions to the carrying values of the commodity inventories included in the Company's accompanying consolidated balance sheets and as charges to other expense in the accompanying consolidated statements of operations.

The following table presents the Company's materials and supplies and commodity inventories as of December 31, 2017 and 2016:

	As of December 31,	
	2017	2016
	(in millions)	
Materials and supplies (a)	$ 134	$ 144
Commodities	78	37
	$ 212	$ 181

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(a) As of December 31, 2017 and 2016, the Company's materials and supplies inventories were net of valuation allowances of $5 million and $28 million, respectively. See Note D for additional information regarding inventory impairments.

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

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

(i) The well has found a sufficient quantity of reserves to justify its completion as a producing well; and
(ii) The Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital-intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration 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 10 gas processing plants and four treating facilities. The Company is the operator of one of the gas processing plants and all four of the treating facilities. Nine of the gas processing plants are operated by third parties and one of the treating facilities is not currently being used. 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 years ended December 31, 2017, 2016 and 2015 were $60 million, $41 million and $39 million, respectively. Third-party expenses attributable to the processing plants and treating facilities in continuing operations for the same respective periods were $26 million, $24 million and $27 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, including vertical integrated services that are used in the development of the assets, is less than the carrying amount of the assets, including the carrying value of vertical integrated services 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 the 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 to 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 2017, the Company performed its annual 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 impairment test. Based on the results of the assessment, the Company determined it was not likely that the Company's goodwill was impaired.

Other property and equipment, net. Other property and equipment is recorded at cost. As of December 31, 2017 and 2016, the net carrying value of other property and equipment consisted of the following:

	As of December 31,	
	2017 (a)	2016 (a)
	(in millions)	
Land and buildings	$ 529	$ 475
Proved and unproved sand properties (b)	488	484
Water infrastructure (c)	347	221
Equipment (d)	194	206
Information technology (e)	143	84
Leasehold improvements	20	22
Vehicles	19	15
Furniture and fixtures	19	22
	$ 1,759	$ 1,529

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(a) At December 31, 2017 and 2016, other property and equipment was net of accumulated depreciation of $936 million and $866 million, respectively.

(b) Includes sand mines, facilities and unproved leaseholds that primarily provide the Company with proppant for use in the fracture stimulation of oil and gas wells.

(c) Includes pipeline infrastructure costs and water supply wells.

(d) Includes fracture stimulation and well servicing equipment that is owned by wholly-owned subsidiaries that provide pressure pumping and well services on Company-operated properties. As of December 31, 2017, the Company owned eight 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.

(e) Information technology costs include hardware and software costs associated with the Company's existing systems and in-progress system upgrades. As of December 31, 2017 and 2016, $93 million and $37 million, respectively, had not yet been placed into service.

The primary purpose of the Company's sand mine, pressure pumping, well services and water infrastructure operations is to assist in the execution of the Company's drilling, completion and production 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 profits or losses of the Company's sand mine, pressure pumping, well services and water infrastructure operations are eliminated.

The capitalized costs of proved sand properties are depleted using the unit-of-production method based on proved sand reserves. Other property and equipment is depreciated over its estimated useful life on a straight-line basis. Buildings are generally depreciated over 20 to 39 years. Equipment, vehicles, furniture and fixtures and information technology assets are generally depreciated over two to 15 years. Water infrastructure is generally depreciated over 10 to 50 years. Leasehold improvements are amortized over the lesser of their estimated useful lives or the underlying terms of the associated leases.

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the asset exceeds its estimated fair value. The estimated fair value is determined using either a discounted future cash flow model or another appropriate fair value method.

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 January and June of 2016, the Company issued 13.8 million and 6.0 million shares of its common stock, respectively, and realized cash proceeds of $1.6 billion and $937 million, respectively, net of associated underwriting and offering expenses.

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 enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's West Texas Intermediate oil ("WTI") sales to a Gulf Coast or export market price and to satisfy unused pipeline capacity commitments. 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 commodities purchased and assuming the responsibility to deliver the commodities sold. Transportation costs associated with purchases and sales of third-party oil and gas are presented on a net basis in purchased oil and gas expense. Firm transportation 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.

Derivatives. All derivatives are recorded in the accompanying consolidated balance sheets at estimated fair value. The Company recognizes all changes in the fair values of its derivative contracts as gains or losses in the earnings of the periods in which they occur.

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 credit-adjusted risk-free rate curve. 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. See Note E for additional information about the Company's derivative instruments.

Income taxes. The provision for income taxes is determined using the asset and liability approach of accounting for income taxes. Under this approach, deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and net operating loss and tax credit carryforwards. The amount of deferred taxes on these temporary differences is determined using the tax rates that are expected to apply to the period when the asset is realized or the liability is settled, as applicable, based on tax rates and laws in the respective tax jurisdiction enacted as of the balance sheet date.

The Company reviews its deferred tax assets for recoverability and establishes a valuation allowance based on projected future taxable income, applicable tax strategies and the expected timing of the reversals of existing temporary differences. A valuation allowance is provided when it is more likely than not (likelihood of greater than 50%) that some portion or all of the deferred tax assets will not be realized.

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recognized. See Note O for additional information regarding uncertain tax positions.

Stock-based compensation. Stock-based compensation expense is being recognized on restricted stock, restricted stock units, performance units and stock option awards that are expected to be settled in the Company's common stock ("Equity Awards") in the Company's consolidated 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. Stock-based compensation awards generally vest over a period of 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.

Stock-based compensation liability awards ("Liability Awards") are restricted stock awards that are expected to be settled in cash on their vesting dates, rather than in common stock. Liability Awards are recorded as accounts payable—affiliates based on the fair value of the vested portion 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.

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 to measure the fair value of Equity Awards and Liability Awards, (iii) the closing stock price on the balance sheet date to measure the fair value of the vested portions of Liability Awards and (iv) the Monte Carlo simulation method to measure the fair value of performance unit awards.

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 development, exploration and production. The Company considers its vertical integration services as ancillary to its oil and gas development, 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.

Restructuring. In February 2016, the Company announced plans to restructure its pressure pumping operations in South Texas, including relocating its two Eagle Ford Shale pressure pumping fleets to the Spraberry/Wolfcamp area. In connection therewith, the Company offered severance to certain employees and relocated a number of other employees from its South Texas locations to its operations in the Permian Basin. The initiative was substantially complete as of December 31, 2016. In connection therewith, the Company recognized $4 million of restructuring charges in other expense in the accompanying consolidated statements of operations during the year ended December 31, 2016. The restructuring costs included $3 million in cash employee severance costs and $1 million in employee relocation and other costs.

In May 2015, the Company announced plans to restructure its operations in Colorado, including closing its office in Denver, Colorado and eliminating its Trinidad-based pressure pumping services operations. The restructuring plan was substantially complete as of December 31, 2015. In connection therewith, the Company recognized $23 million of restructuring charges in other expense in the accompanying consolidated statements of operations during the year ended December 31, 2015. The restructuring costs included $17 million in employee severance costs and $6 million in office lease-related costs. The $17 million of employee severance costs for the year ended December 31, 2015 included $16 million related to cash severance payments and $1 million related to accelerated vesting of share-based grants, which were noncash charges.

Lease obligations and other. The $6 million of office lease-related costs for the year ended December 31, 2015 related to certain Denver office space that will no longer be used, of which $2 million represented the impairment of leasehold improvements and $4 million represented the Company's future obligations under the operating leases, net of anticipated sublease income.

As of December 31, 2017 and 2016, the Company had $1 million and $2 million of restructuring liabilities, respectively, primarily related to future lease obligations recorded in other current and noncurrent liabilities in the accompanying consolidated balance sheets.

New accounting pronouncements. In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2016-09, "Improvements to Employee Share-Based Payment Accounting." ASU 2016-09 simplifies several aspects of the accounting for share-based payment transactions, including accounting for income taxes, forfeitures and statutory tax withholding requirements, as well as certain classification changes in the statement of cash flows. The Company adopted this standard on January 1, 2017. See Note O for discussion on the impact of the adoption to the Company's income tax benefit.

In February 2016, FASB issued ASU 2016-02, "Leases (Topic 842)." ASU 2016-02 requires the recognition of lease assets and lease liabilities by lessees for those leases currently classified as operating leases and makes certain changes to the accounting for lease expenses. This update is effective for fiscal years beginning after December 15, 2018 and for interim periods beginning the following year. This update should be applied using a modified retrospective approach, and early adoption is permitted. The Company anticipates that the adoption of ASU 2016-02 for its leasing arrangements will likely (i) increase the Company's recorded assets and liabilities, (ii) increase depreciation, depletion and amortization expense, (iii) increase interest expense and (iv) decrease lease/rental expense. The Company is currently evaluating each of its lease arrangements and has not determined the aggregate amount of change expected for each category. In January 2018, the FASB issued ASU 2018-01, which permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expire before the Company's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840. The Company intends to elect this transition provision.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)," which supersedes the revenue recognition requirements in Accounting Standards Codification ("ASC") Topic 605, "Revenue Recognition," and most industry-specific guidance. ASU 2014-09 is based on the principle that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. In August 2015, the FASB issued ASU 2015-14, which defers the effective date of ASU 2014-09 for one year to annual reports beginning after December 15, 2017. Early adoption is permitted for fiscal years beginning after December 15, 2016. In addition, in May 2016, the FASB issued ASU 2016-11, which rescinds guidance from the SEC on accounting for gas balancing arrangements and will eliminate the use of the entitlements method.

During the Company's implementation of Topic 606, it identified the following revenue streams: oil, NGL and gas sales and sales of purchased oil and gas. The Company's analysis of contracts with customers in accordance with the requirements of Topic 606 is complete. The Company has not identified any changes to the timing of revenue recognition based upon the requirements of Topic 606 that would have a material impact on the Company's consolidated financial statements. The Company will utilize the modified approach to adopt the new standards on their January 1, 2018 effective date. The Company continues to review its implementation documentation and its evaluation of the new disclosure requirements is ongoing.

NOTE C. Acquisitions and Divestitures

Acquisitions

Permian Basin. In August 2016, the Company acquired approximately 28,000 net acres in the Permian Basin, with net production of approximately 1,400 barrels of oil equivalent per day ("BOEPD"), from an unaffiliated third party for $428 million. The acquisition was accounted for using the acquisition method under ASC 805, "Business Combinations," which requires acquired assets and liabilities to be recorded at fair value as of the acquisition date.

The following table represents the allocation of the acquisition price to the assets acquired and the liabilities assumed based on their fair value at the acquisition date (in millions):

Assets acquired:		
Proved properties	$	79
Unproved properties		347
Other property and equipment		5
Liabilities assumed:		
Asset retirement obligations		(2)
Other liabilities		(1)
Net assets acquired	$	428

The fair value measurements of the net assets acquired are based on inputs that are not observable in the market and, therefore, represent Level 3 inputs in the fair value hierarchy (see Note D for a description of the input levels in the fair value hierarchy). The Company calculated the fair values of the acquired proved properties and asset retirement obligations using a discounted future cash flow model that utilizes management's estimates of (i) proved reserves, (ii) forecasted production rates, (iii) future operating, development and plugging and abandonment costs, (iv) future commodity prices and (v) a discount rate of 10 percent for proved properties and seven percent for asset retirement obligations. The Company calculated the fair values of the acquired unproved properties based on the average price per acre in comparable market transactions. The operating results attributable to the acquired assets and liabilities assumed are included in the Company's accompanying consolidated statements of operations since the date of acquisition.

In connection with the acquisition, the Company incurred acquisition related costs (primarily consulting, advisory and legal fees) of $1 million. The operating results included in the Company's accompanying consolidated statements of operations from the date of acquisition to December 31, 2016, and the operating results that would have been recognized had the acquisition occurred on January 1, 2016, are not material to the Company's accompanying consolidated statements of operations.

Divestitures Recorded in Continuing Operations

The Company recorded net gains on the disposition of assets in continuing operations of $208 million, $2 million and $782 million during the years ended December 31, 2017, 2016 and 2015, respectively. The following describes the significant divestitures included in continuing operations:

- In April 2017, the Company completed the sale of approximately 20,500 acres in the Martin County region of the Permian Basin, with net production of approximately1,500 BOEPD, to an unaffiliated third party for cash proceeds of $264 million. The sale resulted in a gain of $194 million. In conjunction with the divestiture, the Company reduced the carrying value of goodwill by $2 million, reflecting the portion of the Company's goodwill related to the assets sold.

- *EFS Midstream.* In July 2015, the Company completed the sale of its 50.1 percent interest in EFS Midstream LLC ("EFS Midstream"), which was accounted for under the equity method of accounting, to an unaffiliated third party, with the Company receiving total consideration of $1.0 billion, of which $530 million was received at closing, and the remaining $501 million was received in July 2016. Associated with the sale, the Company recorded a gain of $777 million during 2015.

- *Other.* During 2017, 2016 and 2015, the Company sold other proved and unproved properties, inventory and other property and equipment and recorded net gains of $14 million, $2 million and $5 million, respectively. The net gain of $14 million for 2017 is primarily related to the sale of nonstrategic proved and unproved properties in the Permian Basin for cash proceeds of $77 million.

Divestitures Recorded in Discontinued Operations

In 2015, the Company recognized losses from discontinued operations, net of tax, of $7 million related to plugging and abandonment obligations associated with two Gulf of Mexico wells that Pioneer divested in 2009. The results of operations for these assets were recorded in discontinued operations upon their divestiture and therefore the costs incurred subsequent to their divestiture are reflected as discontinued operations in the accompanying consolidated statements of operations.

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, 2017 and 2016 for each of the fair value hierarchy levels:

	Fair Value Measurements at December 31, 2017 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, 2017
	(in millions)			
Assets:				
Commodity derivatives	$ —	$ 11	$ —	$ 11
Deferred compensation plan assets	95	—	—	95
Total assets	95	11	—	106
Liabilities:				
Commodity derivatives	—	255	—	255
Total liabilities	—	255	—	255
Total recurring fair value measurements	$ 95	$ (244)	$ —	$ (149)

	Fair Value Measurements at December 31, 2016 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, 2016
	(in millions)			
Assets:				
Commodity derivatives	$ —	$ 8	$ —	$ 8
Interest rate derivatives	—	6	—	6
Deferred compensation plan assets	83	—	—	83
Total assets	83	14	—	97
Liabilities:				
Commodity derivatives	—	84	—	84
Total liabilities	—	84	—	84
Total recurring fair value measurements	$ 83	$ (70)	$ —	$ 13

Commodity derivatives. The Company's commodity derivatives represent oil, NGL and gas swap contracts, collar contracts and collar contracts with short puts. The asset and liability measurements for the Company's commodity derivative contracts represented Level 2 inputs in the hierarchy. 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 that 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 contracts and collar contracts with short puts, which is based on active and independent market-quoted volatility factors.

Deferred compensation plan assets. 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, 2017 and 2016, the significant inputs to these asset exchange values represented Level 1 independent active exchange market price inputs.

Assets and liabilities measured at fair value on a nonrecurring basis. Certain assets and liabilities are measured at fair value on a nonrecurring basis. These assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances. These assets and liabilities can include inventory, proved and unproved oil and gas properties and other long-lived assets that are written down to fair value when they are impaired or held for sale. See Note C for information on the fair value of assets and liabilities acquired in the Permian Basin acquisition.

Inventories. During the years ended December 31, 2017, 2016 and 2015, the Company recognized noncash impairment charges of $2 million, $8 million and $71 million, respectively, primarily to reduce the carrying value of its excess 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 charges are included in other expense in the Company's accompanying consolidated statements of operations.

Proved oil and gas properties. As a result of the Company's proved property impairment assessments, the Company recognized noncash impairment charges to reduce the carrying values of (i) the Raton field during the year ended December 31, 2017, (ii) the West Panhandle field during the year ended December 31, 2016 and (iii) the Eagle Ford Shale field, the South Texas - Other field and the West Panhandle field during the year ended December 31, 2015.

The Company calculated the fair values of the Raton field, the West Panhandle field, the Eagle Ford Shale field and the South Texas - Other field proved properties using a discounted cash flow model. Significant Level 3 assumptions associated with the calculation of discounted future cash flows included management's longer-term commodity price outlooks ("Management's Price Outlooks") and management's outlooks for (i) production, (ii) capital expenditures, (iii) production costs 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 2017, 2016 and 2015 proved property impairments, as well as the average oil price per barrel ("Bbl") and gas price per British thermal unit ("MMBtu") utilized in the respective Management's Price Outlooks:

		Fair Value	Fair Value Adjustment	Management's Price Outlooks	
				Oil	Gas
Raton	March 2017	$ 186	$ (285)	$ 53.65	$ 3.00
West Panhandle	March 2016	$ 33	$ (32)	$ 49.77	$ 3.24
South Texas - Eagle Ford Shale	December 2015	$ 483	$ (846)	$ 52.82	$ 3.34
South Texas - Other	September 2015	$ 88	$ (72)	$ 57.41	$ 3.46
West Panhandle	March 2015	$ 61	$ (138)	$ 65.02	$ 3.83

It is reasonably possible that the Company's 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 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 reserves.

Unproved oil and gas properties. During March 2016, the Company recorded an impairment charge of $32 million to write-off the carrying value of its unproved royalty acreage in Alaska as a result of the operator curtailing operations in the area and Management's Price Outlooks. During 2015, the Company recorded impairment charges of $7 million to impair the remaining carrying value of its unproved properties in southeast Colorado as a result of the Company no longer planning to develop this acreage and the acreage's limited market value, if any, given the short time period until the leases expire. The Company's impairment charges for unproved oil and gas properties are reported in exploration and abandonments in the 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 accompanying consolidated balance sheets as of December 31, 2017 and 2016 are as follows:

	December 31, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(in millions)			
Commercial paper, corporate bonds and time deposits	$ 1,284	$ 1,282	$ 1,906	$ 1,901
Current portion of long-term debt	$ 449	$ 457	$ 485	$ 490
Long-term debt	$ 2,283	$ 2,479	$ 2,728	$ 2,956

Commercial paper, corporate bonds and time deposits. Periodically, the Company invests in commercial paper and corporate bonds with investment grade rated entities. The Company also periodically enters into time deposits with financial institutions. The investments are carried at amortized cost and classified as held-to-maturity as the Company has the intent and ability to hold them until they mature. The carrying values of held-to-maturity investments are adjusted for amortization of premiums and accretion of discounts over the remaining life of the investment. Income related to these investments is recorded in interest and other income in the Company's consolidated statement of operations. The Company's investments in corporate bonds represent Level 1 inputs in the hierarchy, while other investments represent Level 2 inputs in the hierarchy. Commercial paper and time deposits are included in cash and cash equivalents if they have maturity dates that are less than 90 days at the date of purchase; otherwise, investments are reflected in short-term investments or long-term investments in the accompanying consolidated balance sheets based on their maturity dates. The following tables provide the components of the Company's cash and cash equivalents and investments as of December 31, 2017 and 2016:

	December 31, 2017				
Consolidated Balance Sheet Location	Cash	Commercial Paper	Corporate Bonds	Time Deposits	Total
	(in millions)				
Cash and cash equivalents	$ 846	$ —	$ —	$ 50	$ 896
Short-term investments	—	124	647	447	1,218
Long-term investments	—	—	66	—	66
	$ 846	$ 124	$ 713	$ 497	$ 2,180

	December 31, 2016				
Consolidated Balance Sheet Location	Cash	Commercial Paper	Corporate Bonds	Time Deposits	Total
	(in millions)				
Cash and cash equivalents	$ 873	$ 45	$ —	$ 200	$ 1,118
Short-term investments	—	368	691	382	1,441
Long-term investments	—	—	420	—	420
	$ 873	$ 413	$ 1,111	$ 582	$ 2,979

Debt obligations. The Company's debt obligations are composed of its senior notes whose fair value is determined utilizing inputs that are Level 2 measurements in the fair value hierarchy. The Company's senior notes represent debt securities that are quoted but not actively traded on major exchanges; therefore, 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 receivables, payables and other current assets and liabilities that approximate fair value due to the nature of the instrument and their relatively short maturities. Non-financial assets and liabilities initially measured at fair value include assets acquired and liabilities assumed in a business combination, goodwill and asset retirement obligations.

Concentrations of credit risk. As of December 31, 2017, the Company's primary concentration of credit risks are the risks associated with collecting receivables (principally accounts receivables) and the risk of a counterparty's failure to perform under derivative contracts owed to the Company. See Note L for information regarding the Company's major customers.

With respect to accounts receivables, the Company uses credit and other financial criteria to evaluate the credit standing of the entity obligated to make the payment, and where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the entity or such other credit support as the Company believes is appropriate.

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.

Periodically, the Company may pay a premium to enter into commodity contracts. Premiums paid, if any, have been nominal in relation to the value of the underlying asset in the contract. The Company recognizes the nominal premium payments as an increase to the value of the derivative assets when paid. All derivatives are adjusted to fair value as of each balance sheet date.

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") 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 associated with the Company's outstanding oil derivative contracts as of December 31, 2017 and the weighted average oil prices for those contracts:

	2018				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year Ending December 31, 2019**
Collar contracts:					
Volume (Bbl)	3,000	3,000	3,000	3,000	—
Average price per Bbl:					
Ceiling	$ 58.05	$ 58.05	$ 58.05	$ 58.05	$ —
Floor	$ 45.00	$ 45.00	$ 45.00	$ 45.00	$ —
Collar contracts with short puts (a):					
Volume (Bbl)	149,000	149,000	154,000	159,000	40,000
Price per Bbl:					
Ceiling	$ 57.79	$ 57.79	$ 57.70	$ 57.62	$ 59.62
Floor	$ 47.42	$ 47.42	$ 47.34	$ 47.26	$ 52.00
Short put	$ 37.38	$ 37.38	$ 37.31	$ 37.23	$ 42.00

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(a) Subsequent to December 31, 2017, the Company entered into additional oil collar contracts with short puts for 25,000 Bbl per day of 2019 production with a ceiling price of $62.55 per Bbl, a floor price of $53.80 per Bbl and a short put price of $43.80 per Bbl.

NGL production derivative activities. All material physical sales contracts governing the Company's NGL production are tied directly or indirectly to either Mont Belvieu, Texas or Conway, Kansas NGL component product prices. The Company uses derivative contracts to manage the NGL component product price volatility.

The following table sets forth the volumes per day associated with the Company's outstanding NGL derivative contracts as of December 31, 2017 and the weighted average NGL prices for those contracts:

	2018				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ending December 31, 2019
Ethane basis swap contracts (a):					
Volume (MMBtu)	6,920	6,920	6,920	6,920	6,920
Price differential ($/MMBtu)	$ 1.60	$ 1.60	$ 1.60	$ 1.60	$ 1.60

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(a) The ethane basis swap contracts reduce the price volatility of ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices. The ethane basis swap contracts fix the basis differential on a NYMEX Henry Hub ("HH") MMBtu equivalent basis. The Company will receive the HH price plus the price differential on 6,920 MMBtu per day, which is equivalent to 2,500 Bbls per day of ethane.

Gas production derivative activities. All material physical sales contracts governing the Company's gas production are tied directly or indirectly to HH gas prices or regional index prices where the gas is sold. The Company uses derivative contracts to manage gas price volatility and basis swap contracts to reduce basis risk between HH prices and actual index prices at which the gas is sold.

The following table sets forth the volumes per day associated with the Company's outstanding gas derivative contracts as of December 31, 2017 and the weighted average gas prices for those contracts:

	2018				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year Ending December 31, 2019
Swap contracts (a):					
Volume (MMBtu)	30,000	100,000	100,000	100,000	—
Price per MMBtu	$ 3.37	$ 3.00	$ 3.00	$ 3.00	$ —
Collar contracts with short puts:					
Volume (MMBtu)	100,000	50,000	50,000	50,000	—
Price per MMBtu:					
Ceiling	$ 3.82	$ 3.40	$ 3.40	$ 3.40	$ —
Floor	$ 3.15	$ 2.75	$ 2.75	$ 2.75	$ —
Short put	$ 2.57	$ 2.25	$ 2.25	$ 2.25	$ —
Basis swap contracts:					
Southern California index swap volume (MMBtu) (b)(c)	80,000	40,000	80,000	53,261	80,000
Price differential ($/MMBtu)	$ 0.34	$ 0.30	$ 0.30	$ 0.43	$ 0.31
Houston Ship Channel index swap volume (MMBtu) (b)(d)	3,444	—	—	—	—
Price differential ($/MMBtu)	$ 0.63	$ —	$ —	$ —	$ —

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(a) Subsequent to December 31, 2017, the Company entered into additional swap contracts for 100,000 MMBtu per day of February 2018 production with a price of $3.46 per MMBtu.
(b) The referenced basis swap contracts fix the basis differentials between Permian Basin index prices and southern California or Houston Ship Channel index prices for Permian Basin gas forecasted for sale in southern California or the Gulf Coast region.
(c) Subsequent to December 31, 2017, the Company entered into additional basis swap contracts for 20,000 MMBtu per day of November 2018 through March 2019 production with a price differential of $0.77 per MMBtu.
(d) Subsequent to December 31, 2017, the Company entered into additional basis swap contracts for 10,000 MMBtu per day of February 2018 production with a price differential of $0.82 per MMBtu.

Marketing derivatives. Periodically, 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 swap contracts to mitigate price risk. The following table sets forth the volumes per day associated with the Company's outstanding marketing derivative contracts as of December 31, 2017 and the weighted average prices for those contracts:

	2018			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Average Daily Oil Transportation Commitments Associated with Derivatives (Bbl):				
Basis swap contracts:				
Louisiana Light Sweet index swap volume (a)	10,000	10,000	6,739	—
Price differential ($/Bbl)	$ 3.18	$ 3.18	$ 3.18	$ —
Magellan East Houston index swap volume (a)	11,556	11,703	3,370	—
Price differential ($/Bbl)	$ 3.29	$ 3.30	$ 3.30	$ —

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(a) The referenced basis swap contracts fix the basis differentials between NYMEX WTI and Louisiana Light Sweet or Magellan East Houston oil prices for Permian Basin oil forecasted for sale in the Gulf Coast region.

Interest rate derivatives. During 2017, the Company was party to interest rate derivative contracts whereby the Company would have received the three-month LIBOR rate for the 10-year period from December 2017 through December 2027 in exchange for paying a fixed interest rate of 1.81 percent on a notional amount of $100 million on December 15, 2017. During the fourth quarter of 2017, the Company liquidated its interest rate derivative contracts for cash proceeds of $5 million. As of December 31, 2017, the Company did not have any interest rate derivatives outstanding.

Diesel derivatives. Periodically, the Company enters into diesel derivative swap contracts that mitigate fuel price risk. The diesel derivative swap contracts are priced at an index that is highly correlated to the prices that the Company incurs to fuel its drilling rigs and fracture stimulation fleet equipment. During 2017, the Company liquidated its diesel derivative swap contracts for cash proceeds of $2 million. As of December 31, 2017, the Company did not have any diesel derivative contracts outstanding.

***Tabular disclosure of derivative financial instruments*.** All of the Company's derivatives are accounted for as non-hedge derivatives as of December 31, 2017 and December 31, 2016 and therefore all changes in the fair values of its derivative contracts are recognized 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 as net current or noncurrent derivative assets or net current or noncurrent derivative liabilities, whichever the case may be, by commodity and counterparty. The Company enters into derivatives under master netting arrangements, which, in an event of default, allows the Company to offset payables to and receivables from the defaulting counterparty.

The aggregate fair value of the Company's derivative instruments reported in the accompanying consolidated balance sheets by type and counterparty, including the classification between current and noncurrent assets and liabilities, consists of the following:

Fair Value of Derivative Instruments as of December 31, 2017

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
			(in millions)	
Derivatives not designated as hedging instruments				
Asset Derivatives:				
Commodity price derivatives	Derivatives - current	$ 13	$ (2)	$ 11
Commodity price derivatives	Derivatives - noncurrent	3	(3)	—
				$ 11
Liability Derivatives:				
Commodity price derivatives	Derivatives - current	$ 234	$ (2)	$ 232
Commodity price derivatives	Derivatives - noncurrent	26	(3)	23
				$ 255

Fair Value of Derivative Instruments as of December 31, 2016

Type	Consolidated Balance Sheet Location	Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
			(in millions)	
Derivatives not designated as hedging instruments				
Asset Derivatives:				
Commodity price derivatives	Derivatives - current	$ 33	$ (25)	$ 8
Interest rate derivatives	Derivatives - current	6	—	6
				$ 14
Liability Derivatives:				
Commodity price derivatives	Derivatives - current	$ 102	$ (25)	$ 77
Commodity price derivatives	Derivatives - noncurrent	7	—	7
				$ 84

The following table details the location of gains and losses recognized on the Company's derivative contracts in the accompanying consolidated statements of operations:

Derivatives Not Designated as Hedging Instruments	Location of Gain/(Loss) Recognized in Earnings on Derivatives	Amount of Gain/(Loss) Recognized in Earnings on Derivatives — Year Ended December 31, 2017	2016	2015
		(in millions)		
Commodity price derivatives	Derivative gains (losses), net	$ (99)	$ (174)	$ 873
Interest rate derivatives	Derivative gains (losses), net	(1)	13	6
Total		$ (100)	$ (161)	$ 879

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures.

The following table provides the Company's net derivative assets or liabilities by counterparty as of December 31, 2017:

	Net Assets (Liabilities)
	(in millions)
Macquarie Bank	$ (31)
BMO Financial Group	(30)
JP Morgan Chase	(28)
Citibank, N.A.	(28)
Morgan Stanley	(21)
J. Aron & Company	(21)
BNP Paribas	(20)
Wells Fargo Bank, N.A.	(20)
Merrill Lynch	(20)
Nextera Energy	(17)
Scotia Bank	(5)
Societe Generale	(4)
JP Morgan Ventures Energy Corp	(2)
Toronto Dominion	3
Total	$ (244)

NOTE F. Exploratory Well Costs

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

The following table reflects the Company's capitalized exploratory well and project activity during each of the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Beginning capitalized exploratory well costs	$ 323	$ 306	$ 305
Additions to exploratory well costs pending the determination of proved reserves	1,956	1,387	1,178
Reclassification due to determination of proved reserves	(1,764)	(1,369)	(1,160)
Exploratory well costs charged to exploration and abandonment expense	(10)	(1)	(17)
Ending capitalized exploratory well costs	$ 505	$ 323	$ 306

The following table provides an aging, as of December 31, 2017, 2016 and 2015 of capitalized exploratory costs and the number of projects for which exploratory well costs have been capitalized for a period greater than one year, based on the date drilling was completed:

	As of December 31,		
	2017	2016	2015
		(in millions, except well counts)	
Capitalized exploratory well costs that have been suspended:			
One year or less	$ 493	$ 318	$ 303
More than one year	12	5	3
	$ 505	$ 323	$ 306
Number of projects with exploratory well costs that have been suspended for a period greater than one year	7	3	1

The projects with exploratory well costs that have been suspended for a period greater than one year at December 31, 2017 are in the Eagle Ford Shale area. The Company is evaluating both the well performance of similar wells completed in 2017 and whether to drill additional wells near these wells in order for all of the wells in the area to be fracture stimulated as a package, thereby improving the resource recovery for the area. The Company expects to complete its evaluation of these seven wells during 2018.

NOTE G. Long-term Debt and Interest Expense

Long-term debt, including the effects of issuance costs and issuance discounts, consisted of the following components at December 31, 2017 and 2016:

	December 31, 2017	December 31, 2016
	(in millions)	
Outstanding debt principal balances:		
6.65% senior notes due 2017 (a)	$ —	$ 485
6.875% senior notes due 2018 (b)	450	450
7.500% senior notes due 2020	450	450
3.45% senior notes due 2021	500	500
3.95% senior notes due 2022	600	600
4.45% senior notes due 2026	500	500
7.20% senior notes due 2028	250	250
	2,750	3,235
Issuance costs and discounts	(18)	(22)
Long-term debt	2,732	3,213
Less current portion of long-term debt (a) (b)	449	485
Long-term debt	$ 2,283	$ 2,728

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(a) The 6.65% senior notes, net of $173 thousand of unamortized issuance costs and issuance discounts, are classified as current in the accompanying consolidated balance sheets as of December 31, 2016.

(b) The 6.875% senior notes, net of $106 thousand of unamortized issuance costs and issuance discounts, are classified as current in the accompanying consolidated balance sheets as of December 31, 2017.

Credit facility. During August 2015, the Company entered into a Second Amendment to its Second Amended and Restated 5-year Revolving Credit Agreement ("Credit Facility") with a syndicate of financial institutions (the "Syndicate"), primarily to extend the maturity of the credit facility from December 2017 to August 2020, while maintaining aggregate loan commitments of $1.5 billion. The Company accounted for the entry into the Credit Facility as a modification of the prior agreement and capitalized the debt issuance costs along with those unamortized issuance costs that remained from the issuance of the prior agreement. As of December 31, 2017, the Company had no outstanding borrowings under the Credit Facility.

Borrowings under the Credit Facility may be in the form of revolving loans or swing line loans. Revolving loans represent loans made ratably by the Syndicate in accordance with their respective commitments under the Credit Facility and bear interest, at the option of the Company, based on (a) a rate per annum equal to the higher of the prime rate announced from time to time by Wells Fargo Bank, National Association or the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System during the last preceding business day plus 0.5 percent plus a defined alternate base rate spread margin, which is currently 0.25 percent based upon the Company's debt rating or (b) a base Eurodollar rate, substantially equal to LIBOR, plus a margin (the "Applicable Margin"), which is currently 1.25 percent and is also determined by the Company's debt rating. Swing line loans represent loans made by a subset of the lenders in the Syndicate and may not exceed $150 million. Swing line loans under the Credit Facility bear interest at a rate per annum equal to the "ASK" rate for Federal funds periodically published by the Dow Jones Market Service plus the Applicable Margin. Letters of credit outstanding under the Credit Facility are subject to a per annum fee, representing the Applicable Margin plus 0.125 percent. The Company also pays commitment fees on undrawn amounts under the Credit Facility that are determined by the Company's debt rating (currently 0.15 percent). Borrowings under the Credit Facility are general unsecured obligations.

The Credit Facility requires the maintenance of a ratio of total debt to book capitalization, subject to certain adjustments, not to exceed .60 to 1.0. As of December 31, 2017, the Company was in compliance with all of its debt covenants.

Senior notes. The Company's 6.65% senior notes (the "6.65% Senior Notes") and 5.875% senior notes (the "5.875% Senior Notes") matured and were repaid in March 2017 and July 2016, respectively. The Company funded both the $485 million repayment of the 6.65% Senior Notes and the $455 million repayment of the 5.875% Senior Notes with cash on hand. The Company's 6.875%

senior notes (the "6.875% Senior Notes"), with an outstanding debt principal balance of $450 million, will mature in May 2018. The 6.875% Senior Notes are classified as current in the accompanying consolidated balance sheets as of December 31, 2017.

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

Principal maturities. Principal maturities of long-term debt at December 31, 2017, are as follows (in millions):

2018	$	450
2019	$	—
2020	$	450
2021	$	500
2022	$	600
Thereafter	$	750

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Cash payments for interest	$ 164	$ 196	$ 148
Amortization of issuance discounts	1	9	13
Amortization of capitalized loan fees	4	4	5
Net changes in accruals	(9)	2	25
Interest incurred	160	211	191
Less capitalized interest	(7)	(4)	(4)
Total interest expense	$ 153	$ 207	$ 187

NOTE H. Incentive Plans

Deferred compensation retirement plan. In August 1997, the Compensation Committee of the Company's board of directors (the "Board") approved a deferred compensation retirement plan for the officers and certain key employees of the Company. Each officer and key employee is allowed to contribute up to 25 percent of their base salary and 100 percent of their annual bonus. The Company will provide a matching contribution of 100 percent of the officer's and key employee's contribution limited to the first ten percent of the officer's base salary and eight percent of the key employee's base salary. The Company's matching contribution vests immediately. A trust fund has been established by the Company to accumulate the contributions made under this retirement plan. The Company's matching contributions were $3 million for each of the years ended December 31, 2017, 2016 and 2015, respectively.

401(k) plan. The Pioneer Natural Resources USA, Inc. ("Pioneer USA," a wholly-owned subsidiary of the Company) 401(k) and Matching Plan (the "401(k) Plan") is a defined contribution plan established under the Internal Revenue Code Section 401. All regular full-time and part-time employees of Pioneer USA are eligible to participate in the 401(k) Plan on the first day of the month following their date of hire. Participants may contribute an amount up to 80 percent of their annual salary into the 401(k) Plan. Matching contributions are made to the 401(k) Plan in cash by Pioneer USA in amounts equal to 200 percent of a participant's contributions to the 401(k) Plan that are not in excess of five percent of the participant's base compensation (the "Matching Contribution"). Each participant's account is credited with the participant's contributions, Matching Contributions and allocations of the 401(k) Plan's earnings. Participants are fully vested in their account balances except for Matching Contributions and their proportionate share of 401(k) Plan earnings attributable to Matching Contributions, which proportionately vest over a four-year period that begins with the participant's date of hire. During the years ended December 31, 2017, 2016 and 2015, the Company recognized compensation expense of $25 million, $23 million and $31 million, respectively, as a result of Matching Contributions.

Stock-based compensation costs. In accordance with GAAP, the Company records stock-based compensation expense ratably over the vesting periods of the Company's stock-based compensation awards using the awards' fair value. The Company maintains two plans providing for stock-based compensation: the Amended and Restated 2006 Long-Term Incentive Plan ("LTIP") and the Employee Stock Purchase Plan ("ESPP").

Long-Term Incentive Plan. The LTIP provides for the granting of various forms of awards, including stock options, stock appreciation rights, performance units, restricted stock and restricted stock units to directors, officers and employees of the Company. The shares to be delivered under the LTIP shall be made available from (i) authorized but unissued shares, (ii) shares held as treasury stock or (iii) previously issued shares reacquired by the Company, including shares purchased on the open market. In May 2016, the stockholders of the Company approved a 3.5 million increase in the number of shares available under the plan. The following table shows the number of shares available for issuance pursuant to awards under the LTIP at December 31, 2017:

Approved and authorized awards	12,600,000
Awards issued under plan	(7,657,755)
Awards available for future grant	4,942,245

Employee Stock Purchase Plan. The ESPP allows eligible employees to annually purchase the Company's common stock at a discounted price. Officers of the Company are not eligible to participate in the ESPP. Contributions to the ESPP are limited to 15 percent of an employee's pay (subject to certain ESPP limits) during the eight-month offering period (January 1 to August 31). Participants in the ESPP purchase the Company's common stock at a price that is 15 percent below the closing sales price of the Company's common stock on either the first day or the last day of each offering period, whichever closing sales price is lower. The following table shows the number of shares available for issuance under the ESPP at December 31, 2017:

Approved and authorized shares	1,250,000
Shares issued	(951,285)
Shares available for future issuance	298,715

The following table reflects stock-based compensation expense recorded for each type of stock-based compensation award and the associated income tax benefit for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Restricted stock-Equity Awards	$ 60	$ 66	$ 70
Restricted stock-Liability Awards	24	24	22
Stock options (a)	—	—	—
Performance unit awards	17	21	18
ESPP	2	2	2
Total	$ 103	$ 113	$ 112
Income tax benefit	$ 19	$ 34	$ 34

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(a) Cash proceeds received from stock option exercises during 2017 and 2016 amounted to $300 thousand and $1 million, respectively. There were no stock option exercises during 2015.

As of December 31, 2017, there was $94 million of unrecognized stock-based compensation expense related to unvested share-based compensation plans, including $22 million attributable to Liability Awards that are expected to be settled in cash on their vesting dates. The stock-based compensation expense will be recognized on a straight-line basis over the remaining vesting periods of the awards, which is a period of less than three years on a weighted average basis.

Restricted stock awards. During 2017, the Company awarded 450,619 restricted shares or units of the Company's common stock as compensation to directors, officers and employees of the Company (including 117,984 shares or units representing Liability Awards). The Company's issued shares, as reflected in the accompanying consolidated balance sheet as of December 31, 2017, do not include 77,727 of issued, but unvested shares awarded under stock-based compensation plans that have voting rights.

The following table reflects the restricted stock award activity for the year ended December 31, 2017:

	Equity Awards			Liability Awards
	Number of Shares		Weighted Average Grant-Date Fair Value	Number of Shares
Outstanding at beginning of year	1,077,227	$	143.39	290,552
Shares granted	332,635	$	180.50	117,984
Shares forfeited	(33,283)	$	153.17	(20,687)
Shares vested	(460,356)	$	153.06	(135,114)
Outstanding at end of year	916,223	$	151.71	252,735

The weighted average grant-date fair value of restricted stock equity awards awarded during 2017, 2016 and 2015 was $180.50, $122.72 and $153.55, respectively. The grant-date fair value of restricted stock equity awards that vested during 2017, 2016 and 2015 was $70 million, $66 million and $76 million, respectively.

As of December 31, 2017 and 2016, accounts payable – due to affiliates in the accompanying consolidated balance sheets includes $20 million and $22 million, respectively, of liabilities attributable to the Liability Awards, representing the fair value of the earned, but unvested, portion of the outstanding awards as of that date. The cash paid for Liability Awards that vested during 2017, 2016 and 2015 was $20 million, $18 million and $29 million, respectively.

Stock option awards. Certain employees may be granted options to purchase shares of the Company's common stock with an exercise price equal to the fair market value of Pioneer common stock on the date of grant. The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Option awards have a ten-year contract life. The expected life of an option is estimated based on historical and expected exercise behavior. The volatility assumption was estimated based upon expectations of volatility over the life of the option as measured by historical volatility. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the expected life of the option. The dividend yield was based upon a seven-year average dividend yield.

A summary of the Company's nonstatutory stock option awards activity for the year ended December 31, 2017 is presented below:

	Number of Shares		Weighted Average Exercise Price	Weighted Average Remaining Contractual Life		Aggregate Intrinsic Value
				(in years)		(in millions)
Outstanding at beginning of year	159,378	$	89.03			
Options exercised	(20,885)	$	15.62			
Outstanding at end of year	138,493	$	100.10	3.61	$	10
Exercisable at end of year	138,493	$	100.10	3.61	$	10

The Company has not granted stock options since February 2012. The intrinsic value of options exercised during 2017 and 2016 was $3 million and $6 million, respectively, based on the difference between the market price at the exercise date and the option exercise price. There were no options exercised during 2015.

Performance unit awards. During 2017, 2016 and 2015, the Company awarded performance units to certain of the Company's officers under the LTIP. The number of shares of common stock to be issued is determined by comparing the Company's total shareholder return to the total shareholder return of a predetermined group of peer companies over the performance period. The performance unit awards vest over a 34-month service period. The grant-date fair values per unit of the 2017, 2016 and 2015 performance unit awards were $258.27, $203.69 and $222.33, respectively, which amounts were determined using the Monte Carlo simulation method and are being recognized as stock-based compensation expense ratably over the performance period. The Monte Carlo simulation model utilizes multiple input variables that determine the probability of satisfying the market condition stipulated in the award grant and calculates the fair value of the award. Expected volatilities utilized in the model were estimated using a historical period consistent with the performance period of approximately three years. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the expected life of the grant. The Company used the following assumptions to estimate the fair value of performance unit awards granted during 2017, 2016 and 2015:

	2017	2016	2015
Risk-free interest rate	1.42%	0.96%	1.03%
Range of volatilities	33.6% - 58.2%	28.3% - 53.6%	26.1% - 41.3%

The following table summarizes the performance unit activity for the year ended December 31, 2017:

	Number of Units (a)	Weighted Average Grant-Date Fair Value
Beginning performance unit awards	178,556	$ 211.46
Units granted	59,044	$ 258.27
Units forfeited	—	$ —
Units vested (b)	(74,442)	$ 222.33
Ending performance unit awards	163,158	$ 223.45

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(a) These amounts reflect the number of performance units granted. The actual payout of shares may be between zero percent and 250 percent of the performance units granted depending upon the total shareholder return ranking of the Company compared to peer companies at the vesting date.

(b) On December 31, 2017, the service period lapsed on 78,796 performance unit awards that earned 1.50 shares for each vested award, representing 118,198 aggregate shares of common stock issued on January 2, 2018. The vested performance units that earned 1.50 shares for each vested award included 74,442 units vested in the current year, 4,029 units that vested in 2016 and 325 units that vested in 2015 upon the retirement of the officers to whom the performance unit awards were granted.

The grant-date fair value of performance units that vested during 2017, 2016 and 2015 was $18 million, $15 million and $17 million, respectively.

NOTE I. Asset Retirement Obligations

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations. The following table summarizes the Company's asset retirement obligation activity during the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Beginning asset retirement obligations	$ 297	$ 285	$ 189
Obligations assumed in acquisitions	—	2	—
New wells placed on production	3	2	4
Changes in estimates (a)	(9)	17	103
Dispositions	(7)	—	—
Liabilities settled	(32)	(27)	(23)
Accretion of discount	19	18	12
Ending asset retirement obligations	$ 271	$ 297	$ 285

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(a) Changes in estimates are determined based on several factors, including abandonment cost estimates based on recent actual costs incurred to abandon wells, credit-adjusted risk-free discount rates and well life estimates. The decrease in 2017 was primarily due to a increase in commodity prices, which has the effect of lengthening the economic life of the Company's producing wells. The increase in 2016 was primarily due to the forecasted timing of abandoning the Company's oil and gas wells being accelerated as a result of lower commodity prices, which has the effect of shortening the economic lives of the Company's producing wells.

As of December 31, 2017 and 2016, the current portions of the Company's asset retirement obligations were $41 million and $39 million, respectively.

NOTE J. Commitments and Contingencies

Severance agreements. The Company has entered into severance and change in control agreements with its officers and certain key employees. The current annual salaries for the officers and key employees covered under such agreements total $32 million.

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

Legal actions. The Company is party to 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 these proceedings and claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future annual results of operations. The Company records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

Environmental. Environmental expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Environmental 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.

Obligations following divestitures. In connection with its divestiture transactions, the Company may retain certain liabilities and provides the purchaser certain indemnifications, subject to defined limitations, which may apply to identified pre-closing matters, including matters of litigation, environmental contingencies, royalty obligations and income taxes. The Company does not believe that these obligations are probable of having a material impact on its liquidity, financial position or future results of operations.

Drilling commitments. The Company's principal drilling commitments are related to drilling rig contracts that require the Company to pay day rates for contracted drilling rigs over their contractual term. Certain of the drilling rig day rates are based upon oil prices and are subject to change over the lives of the commitments. In addition, the Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future. The Company recognizes its drilling commitments in the periods in which the rig services are performed.

Lease agreements. The Company leases equipment and office facilities under operating leases. Rent expense for the years ended December 31, 2017, 2016 and 2015 was $69 million, $59 million and $58 million, respectively.

In June 2017, the Company entered into a 20-year operating lease for the Company's new corporate headquarters that is currently being constructed in Irving, Texas. Annual base rent is expected to be $33 million and lease payments are expected to commence once the building is complete, which is anticipated to occur during the second half of 2019. The Company has a variable equity interest in the entity that is constructing the building. The Company is not the primary beneficiary of the variable interest entity and only has a profit sharing interest after certain economic returns are achieved. The Company has no exposure to the variable interest entity's losses or future liabilities, if any. The Company is the deemed owner of the building (for accounting purposes) during the construction period and is following the build-to-suit accounting guidance. Accordingly, as of December 31, 2017, the Company has capitalized $57 million of construction costs, including capitalized interest, within other property and equipment and has recognized a corresponding build-to-suit lease liability of $56 million. The recording of these assets and liabilities are considered noncash investing (other than capitalized interest) and financing items, respectively, for purposes of the consolidated statements of cash flows.

Firm purchase, gathering, processing, transportation and fractionation commitments. The Company from time to time enters into, and as of December 31, 2017 was a party to, take-or-pay agreements, which include contractual commitments to purchase sand and water for use in the Company's drilling operations and contractual commitments with midstream service companies and pipeline carriers for future gathering, processing, transportation, storage and fractionation. These commitments are normal and customary for the Company's business activities. Certain future minimum gathering, processing, transportation, storage and fractionation fees are based upon rates and tariffs that are subject to change over the lives of the commitments.

The Company's minimum commitments as of December 31, 2017 are as follows:

	Drilling Commitments	Lease Commitments	Purchase, Gathering, Processing, Transportation, Storage and Fractionation Commitments	Total
		(in millions)		
2018	$ 93	$ 27	$ 568	$ 688
2019	$ 41	$ 42	$ 619	$ 702
2020	$ 37	$ 53	$ 672	$ 762
2021	$ —	$ 40	$ 627	$ 667
2022	$ —	$ 37	$ 476	$ 513
Thereafter	$ —	$ 680	$ 1,554	$ 2,234
Total minimum commitments	$ 171	$ 879	$ 4,516	$ 5,566

Delivery commitments. The above commitments include demand fees associated with volume delivery commitments that are primarily related to the Permian Basin. If the Company does not expect to be able to fulfill its short-term and long-term delivery obligations from projected production of available reserves, the Company expects to purchase third party volumes, where applicable, to satisfy its commitment assuming it is economic to do so; otherwise, it will pay the demand fees associated with any commitment shortfalls. The Company's delivery commitments as of December 31, 2017 are as follows:

	Oil	Gas
	(MBbls per day)	(MMBtu per day)
2018	66,685	—
2019	63,356	75,342
2020	68,347	100,000
2021	70,000	100,000
2022	30,575	100,000
2023	—	100,000
2024	—	24,863

NOTE K. Related Party Transactions

Transactions with EFS Midstream. Prior to July 2015, the Company, through a wholly-owned subsidiary, owned a noncontrolling interest in its unconsolidated affiliate, EFS Midstream. In July 2015, the Company completed the sale of its interest in EFS Midstream to an unaffiliated third party.

Prior to July 2015, the Company also (i) provided certain services as the manager of EFS Midstream in accordance with a Master Services Agreement and (ii) contracted for services from EFS Midstream under a Hydrocarbon Gathering and Handling Agreement (the "HGH Agreement").

Master Services Agreement. The terms of the Master Services Agreement provided that the Company would perform certain manager services for EFS Midstream and be compensated by monthly fixed payments and variable payments attributable to expenses incurred by employees whose time was substantially dedicated to EFS Midstream's business. During 2015, the Company received $2 million of fixed payments and $9 million of variable payments, from EFS Midstream.

Hydrocarbon Gathering and Handling Agreement. Under the terms of the HGH Agreement, EFS Midstream was obligated to construct certain equipment and facilities capable of gathering, treating and transporting oil and gas production from the Eagle Ford Shale properties operated by the Company. The HGH Agreement obligated the Company to use the EFS Midstream gathering, treating and transportation equipment and facilities. In accordance with the terms of the HGH Agreement, the Company paid EFS Midstream $54 million of gathering and treating fees during 2015 prior to its sale. Such amounts were expensed as oil and gas production costs in the accompanying consolidated statements of operations.

NOTE L. Major Customers

The Company's share of oil and gas production is sold to various purchasers who must be prequalified under the Company's credit risk policies and procedures. The Company records allowances for doubtful accounts based on the age of accounts receivables and the financial condition of its purchasers and, depending on facts and circumstances, may require purchasers to provide collateral or otherwise secure their accounts.

The following purchasers individually accounted for ten percent or more of the Company's consolidated oil, NGL and gas production revenues in at least one of the three years ended December 31, 2017:

	Year Ended December 31,		
	2017	2016	2015
Sunoco Logistics Partners L.P. (a)	21%	19%	18%
Occidental Energy Marketing Inc.	16%	16%	18%
Plains Marketing LP	14%	16%	22%
Enterprise Products Partners L.P.	11%	12%	12%

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(a) Sunoco Logistics Partners L.P. ("Sunoco") acquired Vitol Inc.'s Permian Basin oil systems during the fourth quarter of 2016, and the Company's contracts with Vitol Inc. were transferred to Sunoco.

The loss of any of these significant purchasers could have a material adverse effect on the ability of the Company to sell its oil and gas production.

The Company enters into purchase transactions with third parties and separate sale transactions with third parties to diversify a portion of the Company's WTI oil sales to a Gulf Coast and export market price and to satisfy unused pipeline capacity commitments. The following purchasers individually accounted for ten percent or more of the Company's consolidated oil, NGL and gas revenues from sales of commodities purchased from third parties in at least one of the three years ended December 31, 2017:

	Year Ended December 31,		
	2017	2016	2015
Occidental Energy Marketing Inc.	39%	27%	25%
Valero Marketing and Supply Company	14%	17%	50%
BP Energy	11%	18%	—%
Exxon Mobil	11%	23%	12%

The presentation of certain purchases and sales of third-party oil and gas with the same counterparty has been revised in 2016 and 2015 to present such transactions on a net basis in purchased oil and gas expense. Previously, these purchase and sales, which were carried out as purchases from and sales to the same third party, were separately stated on a gross basis in sales of purchased oil and gas and purchased oil and gas expense. See Note B for additional information about the revision of the Company's revenues and expenses associated with these transactions.

The Company believes that the loss of any of these purchasers would not have an adverse effect on the ability of the Company to sell commodities it purchases from third parties.

NOTE M. Interest and Other Income

The following table provides the components of the Company's interest and other income during the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Interest income	$ 32	$ 22	$ 3
Severance, sales and property tax refunds	13	2	—
Deferred compensation plan income	4	3	4
Other income	4	5	10
Equity interest in income of EFS Midstream (a)	—	—	5
Total interest and other income	$ 53	$ 32	$ 22

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(a) The Company accounted for its investment in EFS Midstream prior to its sale in July 2015 using the equity method. EFS Midstream provided gathering, treating and transportation services for the Company. See Note C for additional information on the Company's sale of EFS Midstream.

NOTE N. Other Expense

The following table provides the components of the Company's other expense during the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Transportation commitment charges (a)	$ 167	$ 109	$ 53
Other	58	49	27
Loss from vertical integration services (b)	17	54	34
Impairment of inventory and other property and equipment (c)	2	8	86
Idle drilling and well service equipment charges (d)	—	64	92
Restructuring charges (e)	—	4	23
Total other expense	$ 244	$ 288	$ 315

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(a) Primarily represents firm transportation payments on excess pipeline capacity commitments.

(b) Loss from vertical integration services primarily represents net margins (attributable to third party working interest owners) that result from Company-provided fracture stimulation and well service operations, which are ancillary to and supportive of the Company's oil and gas joint operating activities, and do not represent intercompany transactions. For the three years ended December 31, 2017, 2016 and 2015, these net losses include $140 million, $147 million and $298 million of gross vertical integration revenues, respectively, and $157 million, $201 million and $332 million of total vertical integration costs and expenses, respectively.

(c) Primarily represents charges to reduce excess materials and supplies inventories to their market values for the years ended December 31, 2017, 2016 and 2015, respectively. See Note D for additional information on the fair value of material and supplies inventory.

(d) Primarily represents expenses attributable to idle drilling rig fees that are not chargeable to joint operations and charges to terminate rig contracts that were not required to meet planned drilling activities.

(e) Represents restructuring costs associated with the Company's restructuring of its operations in South Texas in 2016 and Colorado in 2015. See Note B for additional information on the restructuring charges.

NOTE O. Income Taxes

The Company and its eligible subsidiaries file a consolidated United States federal income tax return. Certain subsidiaries are not eligible to be included in the consolidated United States federal income tax return and separate provisions for income taxes have been determined for these entities or groups of entities. The tax returns and the amount of taxable income or loss are subject to examination by United States federal, state, local and foreign taxing authorities. The Company received tax refunds of $66 million (net of tax payments) during 2016 and made current and estimated tax payments of nil and $43 million (net of tax refunds) during 2017 and 2015, respectively.

The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Pioneer monitors Company-specific, oil and gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs") and other deferred tax attributes in the United States federal, state, local and foreign tax jurisdictions will be utilized prior to their expiration.

Enactment of the Tax Cuts and Jobs Act

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (the "Tax Reform Legislation"), which introduces significant changes to the United States federal income tax law. The changes that most impact the Company include:

- A permanent reduction in the federal corporate income tax rate from 35 percent to 21 percent. The rate reduction is effective for the Company as of January 1, 2018. The application of the rate change on the Company's existing deferred tax liabilities resulted in a $625 million income tax benefit to the Company during 2017.
- The corporate alternative minimum tax ("AMT") for tax years beginning in January 1, 2018 has been repealed. The Tax Reform Legislation provides that existing AMT credit carryovers are refundable beginning in 2018. As of December 31, 2017, the Company had AMT credit carryovers of $20 million that are expected to be fully refunded by 2022.
- The Tax Reform Legislation preserves the deductibility of intangible drilling costs and provides for 100 percent bonus depreciation on personal tangible property expenditures through 2022. The bonus depreciation percentage is phased down from 100 percent beginning in 2023 through 2026.

The Tax Reform Legislation is a comprehensive bill containing other provisions, such as limitations on the deductibility of interest expense and certain executive compensation, that are not expected to materially affect Pioneer. The ultimate impact of the Tax Reform Legislation may differ from the Company's estimates as of December 31, 2017 due to changes in the interpretations and assumptions made by the Company as well as additional regulatory guidance that may be issued.

Uncertain tax positions

The Company recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. As of December 31, 2017 and 2016, the Company had unrecognized tax benefits of $124 million and $112 million, respectively, resulting from research and experimental expenditures related to horizontal drilling and completion innovations. If all or a portion of the unrecognized tax benefit is sustained upon examination by the taxing authorities, the tax benefit will be recognized as a reduction to the Company's deferred tax liability and will affect the Company's effective tax rate in the period it is recognized. The Company is unable to estimate the range of a reasonably likely outcome at this time. The Company expects to substantially resolve the uncertainties associated with the unrecognized tax benefits by December 2018.

The following table sets forth changes in the Company's unrecognized tax benefits:

	Year Ended December 31,	
	2017	2016
Balance at beginning of year	$ 112	$ —
Additions based on tax positions related to the current year	12	112
Reductions for tax positions of prior years	—	—
Balance at end of year	$ 124	$ 112

Other Tax Matters

With respect to income taxes, the Company's policy is to account for interest charges as interest expense and any penalties as other expense in the accompanying consolidated statements of operations. The Company files income tax returns in the United States federal jurisdiction, and various state and foreign jurisdictions. As of December 31, 2017, there are no proposed adjustments in any jurisdiction that would have a significant effect on the Company's future results of operations or financial position. The Company's earliest open years in its key jurisdictions are as follows:

U.S. federal	2012
Various U.S. states	2013

The Company's income tax benefit and amounts separately allocated were attributable to the following items for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Income tax benefit from continuing operations	$ 524	$ 403	$ 155
Income tax benefit from discontinued operations	$ —	$ —	$ 2

The Company's income tax (provision) benefit attributable to income from continuing operations consisted of the following for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions)		
Current:			
U.S. federal	$ 5	$ 22	$ (22)
U.S. state	—	2	(1)
	5	24	(23)
Deferred:			
U.S. federal	526	375	165
U.S. state	(7)	4	13
	519	379	178
Income tax benefit from continuing operations	$ 524	$ 403	$ 155

Reconciliations of the United States federal statutory tax rate to the Company's effective tax rate for income (loss) from continuing operations are as follows for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31,		
	2017	2016	2015
	(in millions, except percentages)		
Income (loss) from continuing operations attributable to common stockholders before income taxes	$ 309	$ (959)	$ (421)
Federal statutory income tax rate	35 %	35%	35%
(Provision) benefit for federal income taxes at the statutory rate	(108)	336	147
State income tax (provision) benefit (net of federal tax)	(4)	3	8
State valuation allowance (net of federal tax)	(1)	(3)	—
Change in federal income tax rate (a)	625	—	—
Equity compensation excess tax benefit (b)	9	—	—
Federal credit for increasing research activities (net of unrecognized tax benefits)	6	68	—
State credit for increasing research activities (net of unrecognized tax benefits and federal tax)	—	4	—
Other	(3)	(5)	—
Income tax benefit from continuing operations	$ 524	$ 403	$ 155
Effective income tax rate, excluding net income attributable to the noncontrolling interests	(170)%	42%	37%

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(a) During 2017, the Company recognized a benefit of $625 million as a result of the December 22, 2017 Tax Reform Legislation that reduces the federal income tax rate beginning in 2018.

(b) During 2017, the Company recognized excess tax benefits of $9 million associated with the adoption of ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting," which requires excess tax benefits or deficiencies associated with the vesting of long-term incentive awards to be recorded as income tax expense or benefit in the statement of operations rather than as an adjustment to additional paid-in capital in the balance sheet.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities related to continuing operations are as follows as of December 31, 2017 and 2016:

	December 31, 2017	December 31, 2016
	(in millions)	
Deferred tax assets:		
Net operating loss carryforward (a)	$ 594	$ 635
Credit carryforwards (b)	87	107
Asset retirement obligations	59	106
Incentive plans	48	81
Net deferred hedge losses	52	32
Other	22	30
Total deferred tax assets	862	991
Deferred tax liabilities:		
Oil and gas properties, principally due to differences in basis, depletion and the deduction of intangible drilling costs for tax purposes	(1,640)	(2,184)
Other property and equipment, principally due to the deduction of bonus depreciation for tax purposes	(121)	(204)
Total deferred tax liabilities	(1,761)	(2,388)
Net deferred tax liability	$ (899)	$ (1,397)

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(a) Net operating loss carryforwards as of December 31, 2017 consist of $2.8 billion of U.S. federal NOLs, which expire between 2032 and 2037, and $164 million of Colorado NOLs, which expire between 2027 and 2037, and are net of a $6 million valuation allowance relating to $125 million of Colorado NOLs that the Company believes will more likely than not expire unutilized.

(b) Credit carryforwards as of December 31, 2017 consist of U.S. federal credits for increasing research activities of $82 million and Texas credits for increasing research activities of $5 million. The U.S. federal and state research credits as of December 31, 2017 exclude $124 million of unrecognized tax benefits.

NOTE P. Net Income Per Share Attributable To Common Stockholders

In the calculation of basic net income (loss) per share attributable to common stockholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common stockholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so. The computation of diluted net income (loss) per share attributable to common stockholders reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. During periods in which the Company realizes a loss from continuing operations attributable to common stockholders, securities or other contracts to issue common stock would not be dilutive to net loss per share and conversion into common stock is assumed not to occur. Diluted net income (loss) per share is calculated under both the two-class method and the treasury stock method and the more dilutive of the two calculations is presented.

The Company's basic net income (loss) per share attributable to common stockholders is computed as (i) net income (loss) attributable to common stockholders, (ii) less participating share- and unit-based basic earnings (iii) divided by weighted average basic shares outstanding. The Company's diluted net income (loss) per share attributable to common stockholders is computed as (i) basic net income (loss) attributable to common stockholders, (ii) plus diluted adjustments to participating undistributed earnings (iii) divided by weighted average diluted shares outstanding.

The following table is a reconciliation of the Company's net income (loss) attributable to common stockholders to basic and diluted net income (loss) attributable to common stockholders for the years ended December 31, 2017, 2016 and 2015:

	Year Ended December 31, 2017	2016	2015
	(in millions)		
Income (loss) from continuing operations	$ 833	$ (556)	$ (266)
Participating basic earnings (a)	(6)	—	—
Basic and diluted net income (loss) from continuing operations	827	(556)	(266)
Basic and diluted net loss from discontinued operations	—	—	(7)
Basic and diluted net income (loss) attributable to common stockholders	$ 827	$ (556)	$ (273)

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(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends with the common equity owners of the Company. Participating share- or unit-based earnings represent the distributed and undistributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

Basic and diluted weighted average common shares outstanding were 170 million, 166 million and 149 million for the years ended December 31, 2017, 2016 and 2015, respectively.

NOTE Q. Subsequent Events

In February 2018, the Company announced its intention to divest its properties in South Texas, Raton and the West Panhandle field and focus its efforts and capital resources to its Permian Basin assets. No assurance can be given that the sales will be completed in accordance with the Company's plans or on terms and at prices acceptable to the Company.

In February 2018, the Board (i) declared a cash dividend of $0.16 per share on Pioneer's outstanding common stock, payable April 12, 2018 to stockholders of record at the close of business on March 29, 2018 and (ii) approved a common stock repurchase program to offset the impact of dilution associated with annual employee stock awards. The stock repurchase program allows for up to $100 million of common stock to be repurchased during 2018.

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Oil & Gas Exploration and Production Activities

The Company has only one reportable operating segment, which is oil and gas development, exploration and production in the United States. See the Company's accompanying consolidated statements of operations for information about results of operations for oil and gas producing activities.

Capitalized Costs

	December 31, 2017	December 31, 2016
	(in millions)	
Oil and gas properties:		
Proved	$ 20,404	$ 18,566
Unproved	558	486
Capitalized costs for oil and gas properties	20,962	19,052
Less accumulated depletion, depreciation and amortization	(9,196)	(8,211)
Net capitalized costs for oil and gas properties	$ 11,766	$ 10,841

Costs Incurred for Oil and Gas Producing Activities **(a)**

	Year Ended December 31, 2017	2016	2015
		(in millions)	
Property acquisition costs:			
Proved	$ 8	$ 78	$ 9
Unproved	128	368	27
Exploration costs	2,033	1,454	1,245
Development costs	628	509	894
Total costs incurred	$ 2,797	$ 2,409	$ 2,175

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

	Year Ended December 31, 2017	2016	2015
		(in millions)	
Proved property acquisition costs	$ —	$ 2	$ —
Exploration costs	2	2	2
Development costs	(19)	17	100
Total	$ (17)	$ 21	$ 102

Reserve Quantity Information

The estimates of the Company's proved reserves as of December 31, 2017, 2016 and 2015 were based on evaluations prepared by the Company's engineers and audited by independent petroleum engineers with respect to the Company's major properties and prepared by the Company's engineers with respect to all other properties. Proved reserves were estimated in accordance with guidelines established by the United States Securities and Exchange Commission (the "SEC") and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions based upon an average of the first-day-of-the-month commodity price during the 12-month period ending on the balance sheet date with no provision for price and cost escalations except by contractual arrangements.

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

The following table provides a rollforward of total proved reserves for the years ended December 31, 2017, 2016 and 2015. Oil and NGL volumes are expressed in thousands of Bbls ("MBbls"), gas volumes are expressed in millions of cubic feet ("MMcf") and total volumes are expressed in thousands of barrels of oil equivalent ("MBOE").

	Year Ended December 31,											
	2017				2016				2015			
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf) (a)	Total (MBOE)
Balance, January 1	378,196	136,941	1,264,729	725,925	311,970	126,344	1,356,487	664,395	352,084	169,244	1,668,872	799,473
Production (b)	(57,878)	(20,078)	(143,464)	(101,867)	(48,926)	(15,922)	(139,510)	(88,100)	(38,452)	(14,086)	(147,173)	(77,067)
Revisions of previous estimates	20,140	44,995	365,275	126,015	(3,912)	1,279	(76,998)	(15,466)	(82,816)	(54,439)	(309,947)	(188,913)
Extensions and discoveries	146,822	49,378	266,347	240,591	117,406	24,735	120,766	162,269	80,726	25,496	143,991	130,221
Sales of minerals-in-place	(4,899)	(918)	(4,898)	(6,633)	(908)	(238)	(1,377)	(1,376)	(16)	(3)	(15)	(21)
Purchases of minerals-in-place	508	179	3,891	1,335	2,566	743	5,361	4,203	444	132	759	702
Balance, December 31	482,889	210,497	1,751,880	985,366	378,196	136,941	1,264,729	725,925	311,970	126,344	1,356,487	664,395

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(a) The proved gas reserves as of December 31, 2017, 2016 and 2015 include 171,623 MMcf, 137,853 MMcf and 144,955 MMcf, respectively, of gas that the Company expected to be produced and utilized as field fuel. Field fuel is gas consumed to operate field equipment (primarily compressors) rather than being delivered to a sales point.

(b) Production for 2017, 2016 and 2015 includes 14,799 MMcf, 15,082 MMcf and 15,531 MMcf of field fuel, respectively.

Revisions of previous estimates. Revisions of previous estimates for 2017 were comprised of 52 million barrels of oil equivalent ("MMBOE") of positive price revisions due to 20 percent increases in both the NYMEX oil and NYMEX gas prices that were used to determine proved oil and gas reserves for 2017, as compared to 2016, in addition to 74 MMBOE of positive revisions that were primarily attributable to improved performance from horizontal wells placed on production in the Spraberry/Wolfcamp prior to 2017 and, to a lesser extent, reductions in costs (based on the Company's cost reduction initiatives during 2017) that had the effect of extending the economic lives of the Company's producing wells. The December 31, 2017 NYMEX price used for oil and gas reserve preparation based upon SEC guidelines was $51.34 per barrel of oil and $2.98 per Mcf of gas, compared to $42.82 per barrel of oil and $2.48 per Mcf of gas at December 31, 2016.

Revisions of previous estimates for 2016 were comprised of 58 million barrels of oil equivalent of negative price revisions due to 15 percent and four percent declines in the NYMEX oil and gas prices, respectively, that were used to determine proved oil and gas reserves for 2016, as compared to 2015, partially offset by 43 MMBOE of positive revisions that were primarily attributable to reductions in cost estimates (based on cost savings achieved during 2016) that had the effect of extending the economic lives of the Company's producing wells. The December 31, 2016 NYMEX price used for oil and gas reserve preparation based upon SEC guidelines was $42.82 per barrel of oil and $2.48 per Mcf of gas, compared to $50.11 per barrel of oil and $2.59 per Mcf of gas at December 31, 2015.

Revisions of previous estimates for 2015 were comprised of 269 MMBOE of negative price revisions due to 47 percent and 40 percent declines in the NYMEX oil and gas prices, respectively, that were used to determine proved oil and gas reserves for 2015, as compared to 2014, partially offset by 80 MMBOE of positive revisions that were primarily attributable to reductions in cost estimates (based on cost savings achieved during 2015) that had the effect of extending the economic lives of the Company's producing wells. The December 31, 2015 NYMEX price used for oil and gas reserve preparation based upon SEC guidelines was $50.11 per barrel of oil and $2.59 per Mcf of gas, compared to $94.98 per barrel of oil and $4.35 per Mcf of gas at December 31, 2014.

Extensions and discoveries. Extensions and discoveries for 2017, 2016 and 2015 were primarily comprised of proved reserve additions attributable to the Company's successful horizontal drilling program in the Spraberry/Wolfcamp and Eagle Ford Shale areas.

Sales of minerals-in-place. Sales of minerals-in-place in 2017 were primarily related to the sale of approximately 20,500 acres in the Martin County region of the Permian Basin. See Note C for additional information regarding the Company's divestitures and discontinued operations.

Purchases of minerals-in-place. Purchases of minerals-in-place during 2017, 2016 and 2015 were primarily attributable to acquisitions in the Company's Spraberry/Wolfcamp area.

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The following table provides the Company's proved developed and proved undeveloped reserves for the years ended December 31, 2017, 2016 and 2015.

	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBOE)
Proved Developed Reserves:				
December 31, 2017	442,364	189,434	1,629,451	903,373
December 31, 2016	343,515	126,928	1,215,861	673,085
December 31, 2015	266,657	112,376	1,284,680	593,146
Proved Undeveloped Reserves:				
December 31, 2017	40,525	21,063	122,429	81,993
December 31, 2016	34,681	10,013	48,868	52,840
December 31, 2015	45,313	13,968	71,807	71,249

The following table summarizes the Company's proved undeveloped reserves activity during the year ended December 31, 2017 (in MBOE).

Beginning proved undeveloped reserves	52,840
Revisions of previous estimates	(7,343)
Extensions and discoveries	51,609
Transfers to proved developed	(15,113)
Ending proved undeveloped reserves	81,993

As of December 31, 2017, the Company had 134 proved undeveloped well locations as compared to 90 and 138 at December 31, 2016 and 2015, respectively. The Company has no proved undeveloped well locations that are scheduled to be drilled more than five years from their original date of booking.

The changes in proved undeveloped reserves during 2017 were comprised of the following items:

Revisions of previous estimates. Revisions of previous estimates were primarily comprised of 7 MMBOE of negative revisions that were related to proved undeveloped reserves that were replaced based on the Company's successful 2017 drilling program.

Extensions and discoveries. Extensions and discoveries were primarily comprised of proved reserve additions attributable to the Company's successful horizontal drilling program in the Spraberry/Wolfcamp area.

Transfers to proved developed. Transfers to proved developed reserves represented those undeveloped proved reserves that moved to proved developed as a result of development drilling. During 2017, the Company incurred $628 million of development costs and developed 29 percent of its proved undeveloped reserves.

The Company uses both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (both vertical and horizontally collected) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores and data measured from the Company's internal core analysis facility. After the geologic area was shown to be continuous, statistical analysis of existing producing wells was conducted to generate areas of reasonable certainty at distances from established production. As a result of this analysis, proved undeveloped reserves for drilling locations within these areas of reasonable certainty were recorded during 2017.

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While the Company expects, based on Management's Price Outlooks, that future operating cash flows will provide adequate funding for future development of its proved undeveloped reserves over the next five years, it may also use any combination of internally-generated cash flows, cash and cash equivalents on hand, sales of short-term and long-term investments, availability under its credit facility, proceeds from divestitures of nonstrategic assets or external financing sources to fund these and other capital expenditures, including exploratory drilling and acquisitions. The following table represents the estimated timing and cash flows of developing the Company's proved undeveloped reserves as of December 31, 2017 (dollars in millions):

Year Ended December 31, (a)	Estimated Future Production (MBOE)	Future Cash Inflows	Future Production Costs	Future Development Costs	Future Net Cash Flows
2018	3,065	$ 111	$ 19	$ 231	$ (139)
2019	8,597	281	58	215	8
2020	9,873	327	64	151	112
2021	8,258	262	56	67	139
2022	7,931	242	57	77	108
Thereafter (b)	44,269	1,462	356	11	1,095
	81,993	$ 2,685	$ 610	$ 752	$ 1,323

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(a) Production and cash flows represent the drilling results from the respective year plus the incremental effects of proved undeveloped drilling beginning in 2018.
(b) The $11 million of future development costs represents net abandonment costs in years beyond the forecasted years.

PIONEER NATURAL RESOURCES COMPANY

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Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying commodity prices used in determining proved reserves (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved reserves less estimated future expenditures (based on year-end estimated costs) to be incurred in developing and producing the proved reserves, discounted using a rate of ten percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and gas properties plus available carryforwards and credits and applying the current tax rates to the difference. The discounted future cash flow estimates do not include the effects of the Company's commodity derivative contracts.

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

The following tables provide the standardized measure of discounted future cash flows as of December 31, 2017, 2016 and 2015, as well as a rollforward in total for each respective year:

	December 31,		
	2017	**2016**	**2015**
	(in millions)		
Oil and gas producing activities:			
Future cash inflows	$ 31,716	$ 19,313	$ 18,805
Future production costs	(13,304)	(10,462)	(11,475)
Future development costs (a)	(1,532)	(1,189)	(1,622)
Future income tax expense	(725)	(55)	—
	16,155	7,607	5,708
10% annual discount factor	(8,004)	(3,417)	(2,464)
Standardized measure of discounted future cash flows	$ 8,151	$ 4,190	$ 3,244

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(a) Includes $639 million, $603 million and $604 million of undiscounted future asset retirement expenditures estimated as of December 31, 2017, 2016 and 2015, respectively, using current estimates of future abandonment costs. See Note I for additional information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

	Year Ended December 31,		
	2017	2016	2015
		(in millions)	
Oil and gas sales, net of production costs	$ (2,713)	$ (1,700)	$ (1,314)
Revisions of previous estimates:			
Net changes in prices and production costs	2,690	(284)	(7,960)
Changes in future development costs	(130)	39	1,204
Revisions in quantities	1,088	(122)	(1,292)
Accretion of discount	770	552	1,125
Changes in production rates, timing and other (a)	(621)	72	(93)
Extensions, discoveries and improved recovery	3,454	2,275	1,597
Development costs incurred during the period	139	142	308
Sales of minerals-in-place	(57)	(12)	—
Purchases of minerals-in-place	10	39	13
Change in present value of future net revenues	4,630	1,001	(6,412)
Net change in present value of future income taxes (b)	(669)	(55)	1,871
	3,961	946	(4,541)
Balance, beginning of year	4,190	3,244	7,785
Balance, end of year	$ 8,151	$ 4,190	$ 3,244

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(a) The Company's changes in Standardized Measure attributable to production rates, timing and other primarily represent changes in the Company's estimates of when proved reserve quantities will be realized.

(b) Reflects the permanent reduction in the federal corporate income tax rate from 35 percent to 21 percent associated with the enactment of the Tax Cuts and Jobs Act. See Note O for additional information.

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Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2017 and 2016, with adjustments to conform to the annual results:

	Quarter			
	First	Second	Third	Fourth
	(in millions, except per share data)			
Year Ended December 31, 2017:				
Oil and gas revenues	$ 809	$ 768	$ 855	$ 1,085
Total revenues and other income:				
As reported (a)	$ 1,468	$ 1,630	$ 1,460	$ 1,526
Adjustment for sales of purchased oil and gas (b)	(168)	(168)	(293)	—
As adjusted	$ 1,300	$ 1,462	$ 1,167	$ 1,526
Total costs and expenses:				
As reported (c)	$ 1,541	$ 1,276	$ 1,494	$ 1,464
Adjustment for purchased oil and gas (b)	(168)	(168)	(293)	—
As adjusted	$ 1,373	$ 1,108	$ 1,201	$ 1,464
Net income (loss) attributable to common stockholders	$ (42)	$ 233	$ (23)	$ 665
Net income (loss) attributable to common stockholders per share:				
Basic	$ (0.25)	$ 1.36	$ (0.13)	$ 3.88
Diluted	$ (0.25)	$ 1.36	$ (0.13)	$ 3.87
Year Ended December 31, 2016:				
Oil and gas revenues	$ 409	$ 613	$ 643	$ 753
Total revenues and other income:				
As reported (a)	685	786	1,186	1,168
Adjustment for sales of purchased oil and gas (b)	(60)	(115)	(129)	(140)
As adjusted	$ 625	$ 671	$ 1,057	$ 1,028
Total costs and expenses:				
As reported (c)	1,093	1,197	1,242	1,253
Adjustment for purchased oil and gas (b)	(60)	(115)	(129)	(140)
As adjusted	$ 1,033	$ 1,082	$ 1,113	$ 1,113
Net income (loss) attributable to common stockholders	$ (267)	$ (268)	$ 22	$ (44)
Net income (loss) attributable to common stockholders per share:				
Basic	$ (1.65)	$ (1.63)	$ 0.13	$ (0.26)
Diluted	$ (1.65)	$ (1.63)	$ 0.13	$ (0.26)

(a) During 2017, the Company's total revenues and other income included net derivative gains of $151 million and $135 million during the first and second quarters, respectively, and net derivative losses of $133 million and $254 million during the third quarter and fourth quarters, respectively. During 2016, the Company's total revenues and other income included net derivative gains of $43 million and $91 million during the first and third quarters, respectively, and net derivative losses of $229 million and $66 million during the second and fourth quarters, respectively.

(b) Represents the revision to present transportation costs associated with purchases and sales of third-party oil and gas on a net basis in purchased oil and gas expense. Previously, these transportation costs were separately stated on a gross basis in sales of purchased oil and gas and purchased oil and gas expense. See Note B for additional information about the revision of the Company's revenues and expenses associated with these transactions.

(c) During the first quarter of 2017, the Company's total costs and expenses included charges of $285 million to impair the carrying value of proved properties in the Raton field. During the first quarter of 2016, the Company's total costs and expenses included charges of $32 million to impair the carrying value of proved properties in the West Panhandle field.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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

Changes in internal control over financial reporting. There have been no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

The Company's management, with the participation of its principal executive officer and principal financial officer assessed the effectiveness, as of December 31, 2017, of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control — Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting at a reasonable assurance level as of December 31, 2017, based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2017. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2017, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and the Board of Directors of Pioneer Natural Resources Company

Opinion on Internal Control over Financial Reporting

We have audited Pioneer Natural Resources Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Pioneer Natural Resources Company (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of Pioneer Natural Resources Company as of December 31, 2017 and 2016, and the related consolidated statements of operations, equity and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and our report dated February 20, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP

Dallas, Texas
February 20, 2018

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The names of the executive officers of the Company and their ages, titles and biographies as of the date hereof are incorporated by reference from Part I of this Report. The other information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2018 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2018 and is incorporated herein by reference.

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

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes information about the Company's equity compensation plans as of December 31, 2017:

	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in first column)
Equity compensation plans approved by security holders:			
Pioneer Natural Resources Company:			
2006 Long-Term Incentive Plan (b)(c)	138,493	$ 100.10	4,942,245
Employee Stock Purchase Plan (d)	—	—	298,715
Total	138,493	$ 100.10	5,240,960

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(a) There are no outstanding warrants or equity rights awarded under the Company's equity compensation plans.

(b) In May 2006, the stockholders of the Company approved the 2006 Long-Term Incentive Plan, which provided for the issuance of up to 9.1 million awards, as was supplementally approved by the stockholders of the Company during May 2009. In May 2016, the stockholders of the Company approved a 3.5 million increase in the number of shares available under the plan. Awards under the 2006 Long-Term Incentive Plan can be in the form of stock options, stock appreciation rights, performance units, restricted stock and restricted stock units.

(c) The number of securities remaining for future issuance has been reduced by the maximum number of shares that could be issued pursuant to outstanding grants of performance units at December 31, 2017.

(d) The number of remaining securities available for future issuance under the Company's Employee Stock Purchase Plan is based on the original authorized issuance of 750,000 shares plus an additional 500,000 shares supplementally approved less 951,285 cumulative shares issued through December 31, 2017.

See Note H of Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for a description of each of the Company's equity compensation plans.

The remaining information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2018 and is incorporated herein by reference.

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

The information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2018 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required in response to this Item will be set forth in the Company's definitive proxy statement for the annual meeting of stockholders to be held during May 2018 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Listing of Financial Statements

Financial Statements

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

- Report of Independent Registered Pubic Accounting Firm
- Consolidated Balance Sheets as of December 31, 2017 and 2016
- Consolidated Statements of Operations for the Years Ended December 31, 2017, 2016 and 2015
- Consolidated Statements of Equity for the Years Ended December 31, 2017, 2016 and 2015
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015
- Notes to Consolidated Financial Statements
- Unaudited Supplementary Information

(b) Exhibits

The exhibits to this Report that are required to be filed pursuant to Item 15(b) are listed below.

(c) Financial Statement Schedules

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

Exhibits

Exhibit Number		Description
2.1 *	—	Agreement for the Sale and Purchase of the Entire Issued Share Capital of Pioneer Natural Resources Anaguid Ltd. and Pioneer Natural Resources Tunisia Ltd. between Pioneer Natural Resources USA, Inc. and OMV (Tunesien) Production GmbH dated January 6, 2011 (incorporated by reference to Exhibit 2.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 1-13245).
3.1	—	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-4 (Amendment No. 2), dated June 26, 1997, Registration No. 333-26951).
3.2	—	Certificate of Amendment of the Amended and Restated Certificate of Incorporation, effective May 18, 2012 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 18, 2012).
3.3	—	Fifth Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 24, 2016).
4.1	—	Form of Certificate of Common Stock, par value $.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-4 (Amendment No. 2), dated June 26, 1997, Registration No. 333-26951).
4.2	—	Indenture dated January 13, 1998, between the Company and The Bank of New York, as trustee (incorporated by reference to Exhibit 99.1 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on January 14, 1998).
4.3	—	First Supplemental Indenture dated as of January 13, 1998, among the Company, Pioneer USA and The Bank of New York, as trustee, with respect to the indenture identified above as Exhibit 4.2 (incorporated by reference to Exhibit 99.2 to the Company's and Pioneer USA's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on January 14, 1998).
4.4	—	Sixth Supplemental Indenture, dated as of May 1, 2006, among the Company, Pioneer USA and The Bank of New York Trust Company, N.A., as trustee, with respect to the indenture identified above as Exhibit 4.2 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 4, 2006).
4.5	—	Indenture dated January 22, 2008 between the Company and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on January 22, 2008).
4.6	—	Second Supplemental Indenture dated November 13, 2009 by and among the Company, Pioneer USA and Wells Fargo Bank, National Association, as trustee, with respect to the indenture identified above as Exhibit 4.10 (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on November 13, 2009).
4.7	—	Indenture dated June 26, 2012 between the Company and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on June 28, 2012).
4.8	—	First Supplemental Indenture, dated June 26, 2012, by and among the Company, Pioneer USA and Wells Fargo Bank, National Association, as trustee, with respect to the indenture identified above as Exhibit 4.13 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on June 28, 2012).
4.9	—	Second Supplemental Indenture, dated December 7, 2015, by and among the Company, Pioneer USA and Wells Fargo Bank, National Association, as trustee, with respect to the indenture identified above as Exhibit 4.13 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K File No. 1-13245, filed with the SEC on December 7, 2015).
10.1	—	Second Amended and Restated 5-Year Revolving Credit Agreement dated as of March 31, 2011, among the Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and certain other lenders (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on April 5, 2011).
10.2	—	First Amendment to Second Amended and Restated 5-Year Revolving Credit Agreement dated as of December 20, 2012, among the Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and certain other lenders (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on December 20, 2012).
10.3	—	Second Amendment to Second Amended and Restated 5-Year Revolving Credit Agreement dated as of August 31, 2015, among the Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, and certain other lenders (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on September 4, 2015).
10.4 **H**	—	The Company's Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-8, Registration No. 333-35087, filed with the SEC on September 8, 1997).

10.5 **H**	—	First Amendment to the Company's Long-Term Incentive Plan, effective as of November 23, 1998 (incorporated by reference to Exhibit 10.72 to the Company's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-13245).
10.6 **H**	—	Amendment No. 2 to the Company's Long-Term Incentive Plan, effective as of May 20, 1999 (incorporated by reference to Exhibit 10.73 to the Company's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-13245).
10.7 **H**	—	Amendment No. 3 to the Company's Long-Term Incentive Plan, effective as of February 17, 2000 (incorporated by reference to Exhibit 10.76 to the Company's Annual Report on Form 10-K for the year ended December 31, 1999, File No. 1-13245).
10.8 **H**	—	Amendment No. 4 to the Company's Long-Term Incentive Plan, effective as of November 20, 2003 (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-13245).
10.9 **H**	—	Amendment No. 5 to the Company's Long-Term Incentive Plan, effective as of May 12, 2004 (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-13245).
10.10 **H**	—	Amendment No. 6 to the Company's Long-Term Incentive Plan, effective as of December 17, 2004 (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-13245).
10.11 **H**	—	Amendment No. 7 to the Company's Long-Term Incentive Plan, effective November 20, 2008 (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on November 25, 2008).
10.12 **H**	—	Pioneer Natural Resources Company Amended and Restated 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 24, 2016).
10.13 **H**	—	Form of Restricted Stock Unit Award Agreement for Non-Employee Directors to be used in connection with initial equity awards under the Company's 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.18 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 1-13245).
10.14 **H**	—	Form of Restricted Stock Unit Award Agreement for Non-Employee Directors to be used in connection with annual equity awards under the Company's 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, File No. 1-13245).
10.15 **H**	—	Form of Restricted Stock Award Agreement between the Company and Timothy L. Dove, with respect to annual awards made under the Company's 2006 Long-Term Incentive Plan, together with a schedule identifying other substantially identical agreements between the Company and each of its other executive officers who received this award and identifying the material differences between each of those agreements and the filed Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, File No. 1-13245).
10.16 **H**	—	Form of Nonstatutory Stock Option Agreement between the Company and each of Scott D. Sheffield and Timothy L. Dove, with respect to awards made under the Company's 2006 Long-Term Incentive Plan, together with a schedule identifying other substantially identical agreements between the Company and each of its other executive officers and identifying the material differences between each of those agreements and the filed Nonstatutory Stock Option Agreement (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, File No. 1-13245).
10.17 **H**	—	Form of Performance Unit Award Agreement between the Company and each of Scott D. Sheffield and Timothy L. Dove, with respect to awards made under the Company's 2006 Long-Term Incentive Plan, together with a schedule identifying other substantially identical agreements between the Company and each of its other executive officers and identifying the material differences between each of those agreements and the filed Performance Unit Award Agreement (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 24, 2016).
10.18 **H**	—	Form of Restricted Stock Unit Agreement between the Company and each of Scott D. Sheffield and Timothy L. Dove, with respect to annual awards made under the Company's 2006 Long-Term Incentive Plan, together with a schedule identifying other substantially identical agreements between the Company and each of its other executive officers who received this award and identifying the material differences between each of those agreements and the filed Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 1-13245), filed with the SEC on May 24, 2016).
10.19 **H**	—	Form of Restricted Stock Award Agreement between the Company and executive officers of the Company with respect to retention awards made under the Company's 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, File No. 1-13245).

10.20 **H**	—	Form of Restricted Stock Unit Award Agreement between the Company and executive officers of the Company with respect to retention awards made under the Company's 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, File No. 1-13245).
10.21 **H**	—	Form of Performance Unit Award Agreement between the Company and Timothy L. Dove, with respect to awards made under the Company's 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, File No. 1-13245).
10.22 **H**	—	Form of Restricted Stock Unit Agreement between the Company and Timothy L. Dove, with respect to annual awards made under the Company's 2006 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, File No. 1-13245).
10.23 **H**	—	Pioneer Natural Resources Company Employee Stock Purchase Plan, as amended and restated, effective September 1, 2007 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, File No. 1-13245).
10.24 **H**	—	First Amendment to Amended and Restated Pioneer Natural Resources Company Employee Stock Purchase Plan, effective September 1, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 18, 2012).
10.25 **H**	—	The Company's Executive Deferred Compensation Plan, Amended and Restated, effective as of August 1, 2002 (incorporated by reference to Exhibit 10.15 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2005, File No. 1-13245).
10.26 **H**	—	Amendment No. 1 to the Company's Executive Deferred Compensation Plan, effective as of January 1, 2007 (incorporated by reference to Exhibit 10.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, File No. 1-13245).
10.27 **H**	—	Amended and Restated Executive Deferred Compensation Plan, effective as of January 1, 2009 (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on November 25, 2008).
10.28 **H**	—	Amendment No. 1 to the Company's Amended and Restated Executive Deferred Compensation Plan, effective January 1, 2009 (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, File No. 1-13245).
10.29 **H**	—	Amendment No. 2 to the Company's Amended and Restated Executive Deferred Compensation Plan, effective January 1, 2011 (incorporated by reference to Exhibit 10.56 to the Company's Annual Report on Form 10-K for the year ended December 31, 2010, File No. 1-13245).
10.30 **H**	—	Amendment No. 3 to the Company's Amended and Restated Executive Deferred Compensation Plan, executed August 19, 2013 and effective January 1, 2009 (incorporated by reference to Exhibit 10.36 to the Company's Annual Report on Form 10-K for the year ended December 31, 2013, File No. 1-13245).
10.31 **H**	—	Amendment No. 4 to the Company's Amended and Restated Executive Deferred Compensation Plan, effective January 1, 2014 (incorporated by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K for the year ended December 31, 2013, File No. 1-13245).
10.32 **H**	—	Amendment No. 5 to the Company's Amended and Restated Executive Deferred Compensation Plan, executed November 15, 2016 (incorporated by reference to Exhibit 10.30 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-13245).
10.33**H**	—	Pioneer USA 401(k) and Matching Plan, Amended and Restated, effective as of January 1, 2013 (incorporated by reference to Exhibit 10.38 to the Company's Annual Report on Form 10-K for the year ended December 31, 2013, File No. 1-13245).
10.34 **H**	—	First Amendment to Pioneer USA 401(k) and Matching Plan dated February 27, 2014 (incorporated by reference to Exhibit 10.37 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 1-13245).
10.35 **H**	—	Second Amendment to Pioneer USA 401(k) and Matching Plan dated November 10, 2014 (incorporated by reference to Exhibit 10.38 to the Company's Annual Report on Form 10-K for the year ended December 31, 2014, File No. 1-13245).
10.36 **H**	—	Third Amendment to Pioneer USA 401(k) and Matching Plan dated May 13, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 1-13245).
10.37 **H**	—	Fourth Amendment to Pioneer USA 401(k) and Matching Plan dated July 7, 2015 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 1-13245).
10.38 **H**	—	Fifth Amendment to Pioneer USA 401(k) and Matching Plan dated October 29, 2015 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 1-13245).

10.39 **H**	—	Sixth Amendment to Pioneer USA 401(k) and Matching Plan dated December 7, 2015 (incorporated by reference to Exhibit 10.41 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015, File No. 1-13245).
10.40 **H**	—	Seventh Amendment to Pioneer USA 401(k) and Matching Plan dated March 8, 2016 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2016, File No. 1-13245).
10.41 **H**	—	Eighth Amendment to Pioneer USA 401(k) and Matching Plan dated August 28, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017, File No. 1-13245).
10.42 **H** (a)	—	Ninth Amendment to Pioneer USA 401(k) and Matching Plan dated November 10, 2017.
10.43 **H** (a)	—	Tenth Amendment to Pioneer USA 401(k) and Matching Plan dated February 6, 2018
10.44 **H**	—	Indemnification Agreement, dated February 21, 2013, between the Company and Thomas D. Arthur, together with a schedule identifying other substantially identical agreements between the Company and each of the other non-employee directors identified on the schedule (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on February 26, 2013).
10.45 **H**	—	Indemnification Agreement, dated March 4, 2013, between the Company and Scott D. Sheffield, together with a schedule identifying other substantially identical agreements between the Company and each of its executive officers identified on the schedule and identifying the material differences between each of those agreements and the filed Indemnification Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on March 8, 2013).
10.46 **H**	—	Indemnification Agreement, dated March 4, 2013, between the Company and J.D. Hall, together with a schedule identifying other substantially identical agreements between the Company and the executive officers identified on the schedule and identifying the material differences between each of those agreements and the filed Indemnification Agreement (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014).
10.47 **H**	—	Indemnification Agreement, dated effective July 23, 2013, between the Company and Stacy P. Methvin, together with a schedule identifying other substantially identical agreements between the Company and each of the other non-employee directors identified on the schedule (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on July 29, 2013).
10.48 **H**	—	Indemnification Agreement, dated March 13, 2014, between the Company and Margaret M. Montemayor (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
10.49 **H**	—	Indemnification Agreement, dated July 7, 2014, between the Company and Phillip A. Gobe, together with a schedule identifying other substantially identical agreement between the Company and the other non-employee director identified on the schedule (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on July 10, 2014).
10.50 **H**	—	Indemnification Agreement, dated June 29, 2015, between the Company and Mona K. Sutphen, together with a schedule identifying other substantially identical agreement between the Company and the other non-employee director identified on the schedule (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 1-13245).
10.51 **H**	—	Indemnification Agreement, dated effective March 2, 2016 between the Company and Teresa A. Fairbrook, together with a schedule identifying other substantially identical agreements between the Company and the executive officers identified on the schedule and identifying the material differences between each of those agreements and the filed Indemnification Agreement (incorporated by reference to Exhibit 10.46 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-13245).
10.52 **H**	—	Severance Agreement dated August 16, 2005, between the Company and Scott D. Sheffield, together with a schedule identifying other substantially identical agreements between the Company and each of its executive officers identified on the schedule and identifying the material differences between each of those agreements and the filed Severance Agreement (incorporated by reference to Exhibit 10.24 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, File No. 1-13245).
10.53 **H**	—	Form of Amendment to Severance Agreement dated November 20, 2008, between the Company and each of Scott D. Sheffield and Timothy L. Dove (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on November 25, 2008).
10.54 **H**	—	Form of Amendment to Severance Agreement dated November 20, 2008, between the Company and each executive officer of the Company other than Scott D. Sheffield and Timothy L. Dove (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on November 25, 2008).
10.55 **H**	—	Letter Agreement dated May 19, 2016 between the Company and Scott D. Sheffield (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on May 24, 2016).

10.56 **H**	—	Amended and Restated Severance Agreement dated February 27, 2017, between the Company and Timothy L. Dove (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 1-13245, filed with the SEC on March 3, 2017).
10.57 **H**	—	Severance Agreement, dated effective August 10, 2005, between the Company and Kenneth Sheffield, together with a schedule identifying the other substantially identical agreement between the Company and the executive officer identified on the schedule and identifying the material differences between that agreement and the filed Severance Agreement (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 1-13245).
10.58 **H**	—	Amendment to Severance Agreement, dated December 8, 2008, between the Company and Kenneth Sheffield, together with a schedule identifying the other substantially identical agreement between the Company and the executive officer identified on the schedule and identifying the material differences between that agreement and the filed Amendment to Severance Agreement (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 1-13245).
10.59 **H**	—	Severance Agreement, dated effective January 14, 2010, between the Company and J. D. Hall (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 1-13245).
10.60 **H**	—	Severance Agreement, dated effective January 1, 2014, between the Company and Margaret M. Montemayor (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, File No. 1-13245).
10.61 **H**	—	Severance Agreement, dated effective December 12, 2005, between the Company and William Hannes, together with a schedule identifying the other substantially identical agreement between the Company and the executive officer identified on the schedule and identifying the material differences between that agreement and the filed Severance Agreement (incorporated by reference to Exhibit 10.55 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-3245).
10.62 **H**	—	Amendment to Severance Agreement, dated November 20, 2008, between the Company and William Hannes, together with a schedule identifying the other substantially identical agreement between the Company and the executive officer identified on the schedule and identifying the material differences between that agreement and the filed Amendment to Severance Agreement (incorporated by reference to Exhibit 10.56 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-3245).
10.63 **H**	—	Severance Agreement, dated effective February 27, 2013, between the Company and Teresa A. Fairbrook, together with a schedule identifying the other substantially identical agreement between the Company and the executive officer identified on the schedule and identifying the material differences between that agreement and the filed Severance Agreement (incorporated by reference to Exhibit 10.57 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-3245).
10.64 **H**	—	Separation Agreement, dated effective January 4, 2016, between the Company and Danny Kellum (incorporated by reference to Exhibit 10.56 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015, File No. 1-13245).
10.65 **H**	—	Change in Control Agreement, dated March 4, 2013, between the Company and Scott D. Sheffield, together with a schedule identifying other substantially identical agreements between the Company and each of its executive officers identified on the schedule and identifying the material differences between each of those agreements and the filed Change in Control Agreement (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 1-13245).
10.66 **H**	—	Change in Control Agreement, dated March 4, 2013, between the Company and J. D. Hall, together with a schedule identifying other substantially identical agreements between the Company and the executive officers identified on the schedule and identifying the material differences between each of those agreements and the filed Change in Control Agreement (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 1-13245).
10.67 **H**	—	Change in Control Agreement, dated March 13, 2014, between the Company and Margaret M. Montemayor (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, File No. 1-13245).
10.68 **H**	—	Change in Control Agreement, dated February 27, 2013, between the Company and Teresa A. Fairbrook (incorporated by reference to Exhibit 10.62 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-3245).
10.69 **H**	—	Change in Control Agreement, dated March 4, 2013, between the Company and William F. Hannes, together with a schedule identifying other substantially identical agreements between the Company and the executive officers identified on the schedule and identifying the material differences between each of those arrangements and the filed Change in Control Agreement (incorporated by reference to Exhibit 10.63 to the Company's Annual Report on Form 10-K for the year ended December 31, 2016, File No. 1-3245).
10.70 **H**	—	Form of Amendment to Severance Agreement and Change in Control Agreement dated May 17, 2017, between the Company and each executive officer of the Company (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, File No. 1-13245).

12.1 (a)	—	Computation of Ratios of Earnings to Fixed Charges and Earnings to Fixed Charges and Preferred Stock Dividends.
21.1 (a)	—	Subsidiaries of the registrant.
23.1 (a)	—	Consent of Ernst & Young LLP.
23.2 (a)	—	Consent of Netherland, Sewell & Associates, Inc.
31.1 (a)	—	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 (a)	—	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 (b)	—	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 (b)	—	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
95.1 (a)	—	Mine Safety Disclosure pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act.
99.1 (a)	—	Report of Netherland, Sewell & Associates, Inc.
101. INS (a)	—	XBRL Instance Document.
101. SCH (a)	—	XBRL Taxonomy Extension Schema.
101. CAL (a)	—	XBRL Taxonomy Extension Calculation Linkbase Document.
101. DEF (a)	—	XBRL Taxonomy Extension Definition Linkbase Document.
101. LAB (a)	—	XBRL Taxonomy Extension Label Linkbase Document.
101. PRE (a)	—	XBRL Taxonomy Extension Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

H Executive Compensation Plan or Arrangement.

ITEM 16. 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PIONEER NATURAL RESOURCES COMPANY

Date: February 20, 2018

By: /s/ Timothy L. Dove

Timothy L. Dove,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

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Signature	Title	Date
/s/ Timothy L. Dove Timothy L. Dove	President and Chief Executive Officer (principal executive officer)	February 20, 2018
/s/ Richard P. Dealy Richard P. Dealy	Executive Vice President and Chief Financial Officer (principal financial officer)	February 20, 2018
/s/ Margaret M. Montemayor Margaret M. Montemayor	Vice President and Chief Accounting Officer (principal accounting officer)	February 20, 2018
/s/ Scott D. Sheffield Scott D. Sheffield	Chairman of the Board	February 20, 2018
/s/ Edison C. Buchanan Edison C. Buchanan	Director	February 20, 2018
/s/ Andrew F. Cates Andrew F. Cates	Director	February 20, 2018
/s/ Phillip A. Gobe Phillip A. Gobe	Director	February 20, 2018
/s/ Larry R. Grillot Larry R. Grillot	Director	February 20, 2018
/s/ Stacy P. Methvin Stacy P. Methvin	Director	February 20, 2018
/s/ Royce W. Mitchell Royce W. Mitchell	Director	February 20, 2018
/s/ Frank A. Risch Frank A. Risch	Director	February 20, 2018
/s/ Mona K. Sutphen Mona K. Sutphen	Director	February 20, 2018
/s/ J. Kenneth Thompson J. Kenneth Thompson	Director	February 20, 2018
/s/ Phoebe A. Wood Phoebe A. Wood	Director	February 20, 2018
/s/ Michael D. Wortley Michael D. Wortley	Director	February 20, 2018

EXHIBIT 10.42

NINTH AMENDMENT TO THE
PIONEER NATURAL RESOURCES USA, INC.
401(k) AND MATCHING PLAN
(Amended and Restated Effective as of January 1, 2013)

THIS NINTH AMENDMENT is made and entered into by Pioneer Natural Resources USA, Inc. (the "**Company**"):

WITNESSETH:

WHEREAS, the Company maintains the Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (the "**Plan**");

WHEREAS, pursuant to Section 8.3 of the Plan, the Benefit Plan Design Committee (the "**Committee**") of the Company maintains the authority to amend the Plan at any time; and

WHEREAS, the Committee desires to amend the Plan to provide for full and immediate vesting in any employer-derived benefits accrued under the Plan for certain employees who are involuntarily terminated in connection with the closing or restructuring of certain offices.

NOW THEREFORE, the Plan is hereby amended as follows.

1. Section 5.3(o) is hereby added to the Plan as follows:

(n) Any provision of this Plan to the contrary notwithstanding, the amounts credited to the Employer Account of a Participant who is specifically designated by the Vice President and Chief Human Resources Officer of the Company as being involuntarily terminated in connection with the closing on or about December 1, 2017 of the Colorado Springs plant shall become fully vested and nonforfeitable on the date of such involuntary termination.

NOW, THEREFORE, be it further provided that except as provided above, the Plan shall continue to read in its current state.

IN WITNESS WHEREOF, the Company has executed this Ninth Amendment this 10th day of November, 2017 to be effective as specified above.

PIONEER NATURAL RESOURCES USA, INC.

By: /s/ Teresa A. Fairbrook
Name: Teresa A. Fairbrook
Title: Vice President and Chief Human Resources Officer

EXHIBIT 10.43

TENTH AMENDMENT TO THE
PIONEER NATURAL RESOURCES USA, INC.
401(k) AND MATCHING PLAN
(Amended and Restated Effective as of January 1, 2013)

THIS TENTH AMENDMENT is made and entered into by Pioneer Natural Resources USA, Inc. (the "**Company**"):

WITNESSETH:

WHEREAS, the Company maintains the Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan (the "**Plan**");

WHEREAS, pursuant to Section 8.3 of the Plan, the Benefit Plan Design Committee (the "**Committee**") of the Company maintains the authority to amend the Plan at any time; and

WHEREAS, the Committee desires to amend the Plan to increase the automatic enrollment percentage for Covered Employees and remove the mandatory automatic increase program for Covered Employees.

NOW THEREFORE, the Plan is hereby amended as follows.

1. Effective January 29, 2018, Section 2.2 is hereby amended as follows:

Section 2.2 Participation. Each Covered Employee who is eligible to participate in the Plan may elect, in the manner prescribed by the Committee, to participate in this Plan as soon as administratively practicable but no later than 31 days following the completion and submission of such election.

(a) Automatic Enrollment. For a Covered Employee who is notified that he or she is eligible to participate in the Plan on or after January 29, 2018 and fails to return an alternate election pursuant to Section 3.1(a), Pre-Tax Contributions will automatically begin being made on such Covered Employee's behalf at the rate specified in Section 3.1(a) on the later to occur of (a) the thirtieth day following the Covered Employee's Employment Date, (b) the thirtieth day following the date such Covered Employee satisfies the eligibility requirements set forth in Section 2.1, or (c) the thirtieth day following the date such Covered Employee is notified of the Plan's automatic enrollment provisions in accordance with section 401(k)(13)(E)(i) of the Code. A Covered Employee who desires to make an alternate election pursuant to Section 3.1(a) must do so in the manner prescribed by the Committee.

(b) Covered Employees in Enrollment Period on January 29, 2018. A Covered Employee who was notified that he or she was eligible to participate in the Plan prior to January 29, 2018 and on January 29, 2018 was in his or her enrollment period and fails to return an alternate election pursuant to Section 3.1(a), Pre-Tax

Contributions will automatically begin being made on such Covered Employee's behalf at the rate in effect as of the date he or she was notified that he or she was eligible to participate in the Plan on the thirtieth day following the date such Covered Employee is notified of the Plan's automatic enrollment provisions in accordance with section 401(k)(13)(E)(i) of the Code. On March 1, 2018, a Covered Employee described in this Section 2.2(b) will receive notification that his or her combined Pre-Tax Contribution and Roth Contribution rate will be increased to 5%, and if such Covered Employee fails to return an alternate election pursuant to Section 3.1(a) and such Covered Employee's current combined rate is less than 5%, Pre-Tax Contributions will automatically be increased such that the combined Pre-Tax and Roth Contribution rate for each such Covered Employee is 5% on the thirtieth day following the date such Covered Employee is notified. A Covered Employee who desires to make an alternate election pursuant to Section 3.1(a) must do so in the manner prescribed by the Committee.

(c) Plan Contribution Sweep. Effective January 29, 2018, each Covered Employee (including any Covered Employee who has previously opted out of participation in the Plan or has made an alternate election and excluding those Covered Employees set forth below) will receive notice that his or her combined Pre-Tax Contribution and Roth Contribution rate will be increased to 5%, and if such Covered Employee fails to return an alternate election pursuant to Section 3.1(a) and such Covered Employee's current combined rate is less than 5%, Pre-Tax Contributions will automatically be increased such that the combined Pre-Tax and Roth Contribution rate for each such Covered Employee is 5% on the thirtieth day following the date such Covered Employee is notified. Covered Employees under this Section 2.2(c) will not include any Covered Employee described in Section 2.2(b), any Covered Employee whose election has been suspended in accordance with the terms of the Plan, any Covered Employee with a pending election change, any Covered Employee who participates in the Vanguard Managed Account Program, or any Covered Employee who is a member of a collective bargaining unit. A Covered Employee who desires to make an alternate election pursuant to Section 3.1(a) must do so in the manner prescribed by the Committee.

2. Effective January 29, 2018, Section 2.3 is hereby amended as follows:

Section 2.3 Reemployed Participant. Any Participant who ceases to be a Covered Employee shall thereupon cease to be eligible to participate in the Plan; provided, however, that if any such Participant is thereafter reemployed as a Covered Employee, he or she shall be automatically enrolled in the Plan pursuant to Section 3.1(a).

3. Effective January 29, 2018, Section 3.1(a) is hereby amended as follows:

(a) Each Participant may elect to have his or her Employer make a Pre-Tax Contribution to the Plan on his or her behalf for each pay period in an amount up to 80% of his or her Basic Compensation for that pay period, subject to any other deductions from the Participant's Basic Compensation that are required by law or authorized by the Participant pursuant to a compensation reduction agreement. All such contributions shall be made by uniform payroll deductions pursuant to a compensation reduction agreement which authorizes the Employer to pay such contributions to the Trustee on behalf of the Participant. However, for any Participant subject to the Plan's automatic enrollment provisions (as described in Section 2.2) who fails to make an alternate election, Pre-Tax Contributions will automatically begin being made on such Participant's behalf, in an amount equal to 5% of his or her Basic Compensation on the date specified in Section 2.2 with respect to such Participant. In the event a Participant does not desire to have Pre-Tax Contributions made on his or her behalf at the level set by this Section 3.1(a), the Participant may elect a different amount up to 80% of his or her Basic Compensation in the manner prescribed by the Committee.

3. Effective January 29, 2018, Section 3.1(d) is hereby amended as follows:

(d) A Participant may change the applicable percentage of such payroll (or bonus) deductions or suspend his or her election to have Pre-Tax Contributions and/or Pre-Tax Bonus Contributions made to the Plan at any time. Any such change or suspension will be effective as soon as administratively practicable but no later than 31 days following the submission of such change or submission. Participants will have access to a voluntary percentage increase program.

NOW, THEREFORE, be it further provided that except as provided above, the Plan shall continue to read in its current state.

IN WITNESS WHEREOF, the Company has executed this Tenth Amendment this 6th day of February, 2018 to be effective as specified above.

PIONEER NATURAL RESOURCES USA, INC.

By: /s/ Teresa A. Fairbrook
Name: Teresa A. Fairbrook
Title: Vice President and Chief Human Resources Officer

EXHIBIT 12.1

RATIOS OF EARNINGS TO FIXED CHARGES AND EARNINGS TO FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

The following table sets forth the Company's ratios of consolidated earnings to fixed charges and earnings to fixed charges and preferred stock dividends for the periods presented:

	Year ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Ratio of earnings to fixed charges (a)	2.84	(b)	(c)	9.45	(d)
Ratio of earnings to fixed charges and preferred stock (e)	2.84	(b)	(c)	9.45	(d)

____

(a) The ratio has been computed by dividing earnings by fixed charges. For purposes of computing the ratio:

- earnings consist of income from continuing operations before income taxes, cumulative effect of change in accounting principle, adjustments for net income or loss attributable to the noncontrolling interest and the Company's share of investee's income or loss accounted for under the equity method, and adjustment for capitalized interest, plus fixed charges and the Company's share of distributed income from investees accounted for under the equity method; and

- fixed charges consist of interest expense, capitalized interest and the portion of rental expense deemed to be representative of the interest component of rental expense.

(b) The ratio indicates a less than one-to-one coverage because the earnings are inadequate to cover the fixed charges during the year ended December 31, 2016 by $963 million.

(c) The ratio indicates a less than one-to-one coverage because the earnings are inadequate to cover the fixed charges during the year ended December 31, 2015 by $432 million.

(d) The ratio indicates a less than one-to-one coverage because the earnings are inadequate to cover the fixed charges during the year ended December 31, 2013 by $606 million.

(e) The ratio has been computed by dividing earnings by fixed charges and preferred stock dividends. For purposes of computing the ratio:

- earnings consist of income from continuing operations before income taxes, cumulative effect of change in accounting principle, adjustments for net income or loss attributable to the noncontrolling interest and the Company's share of investee's income or loss accounted for under the equity method, and adjustment for capitalized interest, plus fixed charges, the Company's share of distributed income from investees accounted for under the equity method and preferred stock dividends, net of preferred stock dividends of a consolidated subsidiary; and

- fixed charges and preferred stock dividends consist of interest expense, capitalized interest and the portion of rental expense deemed to be representative of the interest component of rental expense, preferred stock dividends of a consolidated subsidiary and preferred stock dividends.

EXHIBIT 21.1

SUBSIDIARIES OF THE COMPANY

Subsidiaries	**State or Jurisdiction of Organization**
Pioneer Natural Resources USA, Inc.	Delaware
DMLP CO.	Delaware
Long Canyon Gas Company, LLC	Colorado
Lorencito Gas Gathering, LLC	Colorado
Mesa Environmental Ventures Co.	Delaware
Petroleum South Cape (Pty) Ltd.	South Africa
Pioneer Hutt Wind Energy LLC	Delaware
Pioneer Natural Gas Company	Texas
Pioneer Natural Resources Foundation	Texas
Pioneer Natural Resources Pumping Services LLC	Delaware
Industrial Sands Holding Company	Delaware
Pioneer Sands LLC	California
Pioneer Natural Resources South Africa (Pty) Limited	South Africa
Pioneer Natural Resources (Tierra del Fuego) S.R.L.	Argentina
Pioneer Natural Resources Well Services LLC	Delaware
Pioneer Resources Gabon Limited	Bahamas
Pioneer Water Management LLC	Delaware
Pioneer Uravan, Inc.	Texas
PNR Acquisitions LLC	Delaware
Pioneer International Resources Company	Delaware
LF Holding Company LDC	Cayman Islands
Parker & Parsley Argentina, Inc.	Delaware
TDF Holding Company LDC	Cayman Islands

Note: Inclusion in the list is not a representation that the subsidiary is a significant subsidiary.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No. 333-218255) of Pioneer Natural Resources Company and Pioneer Natural Resources USA, Inc. and in the related Prospectus,

(2) Registration Statement (Form S-8 No. 333-136488) pertaining to the Pioneer Natural Resources Company Executive Deferred Compensation Plan,

(3) Registration Statement (Form S-8 No. 333-136489) pertaining to the Pioneer Natural Resources Company 2006 Long-Term Incentive Plan,

(4) Registration Statement (Form S-8 No. 333-136490) pertaining to the Pioneer Natural Resources Company Long-Term Incentive Plan,

(5) Registration Statement (Form S-8 No. 333-88438) pertaining to the Pioneer Natural Resources Company Long-Term Incentive Plan,

(6) Registration Statement (Form S-8 No. 333-39153) pertaining to the Pioneer Natural Resources Company Deferred Compensation Retirement Plan,

(7) Registration Statement (Form S-8 No. 333-39249) pertaining to the Pioneer Natural Resources USA, Inc. Profit Sharing 401(k) Plan,

(8) Registration Statement (Form S-8 No. 333-35087) pertaining to the Pioneer Natural Resources Company Long-Term Incentive Plan,

(9) Registration Statement (Form S-8 No. 333-161283) pertaining to the Pioneer Natural Resources Company 2006 Long Term Incentive Plan,

(10) Registration Statement (Form S-8 No. 333-176712) pertaining to the Pioneer Natural Resources Company Employee Stock Purchase Plan,

(11) Registration Statement (Form S-8 No. 333-178671) pertaining to the Pioneer Natural Resources USA, Inc. 401(k) and Matching Plan, the Pioneer Natural Resources Company 2006 Long-Term Incentive Plan and the Pioneer Natural Resources Company Executive Deferred Compensation Plan,

(12) Registration Statement (Form S-8 No. 333-183379) pertaining to the Pioneer Natural Resources Company Employee Stock Purchase Plan, and

(13) Registration Statement (Form S-8 No. 333-212774) pertaining to the Pioneer Natural Resources Company Amended and Restated 2006 Long Term Incentive Plan,

of our reports dated February 20, 2018, with respect to the consolidated financial statements of Pioneer Natural Resources Company and the effectiveness of internal control over financial reporting of Pioneer Natural Resources Company included in this Annual Report (Form 10-K) of Pioneer Natural Resources Company for the year ended December 31, 2017.

/s/ Ernst & Young LLP

Dallas, Texas
February 20, 2018

EXHIBIT 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm, in the context in which they appear, and to the references to and the incorporation by reference of our audit letter dated January 31, 2018, included in the Annual Report on Form 10-K of Pioneer Natural Resources Company (the "Company") for the fiscal year ended December 31, 2017, as well as in the notes to the financial statements included therein. We also hereby consent to the incorporation by reference of the references to our firm, in the context in which they appear, and to our audit letter dated January 31, 2018, into the Company's previously filed Registration Statements on Form S-8 (No. 333-176712, No. 333-178671, No. 333-35087, No. 333-39153, No. 333-39249, No. 333-88438, No. 333-136488, No. 333-136489, No. 333-136490, No. 333-161283, No. 333-183379 and No. 333-212774) and on Form S-3 (No. 333-218255) in accordance with the requirements of the Securities Act of 1933, as amended.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

Dallas, Texas
February 20, 2018

EXHIBIT 31.1

CHIEF EXECUTIVE OFFICER CERTIFICATION

I, Timothy L. Dove, certify that:

1. I have reviewed this Annual Report on Form 10-K of Pioneer Natural Resources Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 20, 2018

/s/ Timothy L. Dove

Timothy L. Dove, President and Chief Executive Officer

EXHIBIT 31.2

CHIEF FINANCIAL OFFICER CERTIFICATION

I, Richard P. Dealy, certify that:

1. I have reviewed this Annual Report on Form 10-K of Pioneer Natural Resources Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 20, 2018

/s/ Richard P. Dealy

Richard P. Dealy, Executive Vice President
and Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PIONEER NATURAL RESOURCES COMPANY
PURSUANT TO 18 U.S.C. § 1350

I, Timothy L. Dove, President and Chief Executive Officer of Pioneer Natural Resources Company (the "Company"), hereby certify that the accompanying Annual Report on Form 10-K for the year ended December 31, 2017 and filed with the Securities and Exchange Commission pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report") by the Company fully complies with the requirements of that section.

I further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ Timothy L. Dove
Name:	Timothy L. Dove, President and Chief Executive Officer
Date:	February 20, 2018

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PIONEER NATURAL RESOURCES COMPANY
PURSUANT TO 18 U.S.C. § 1350

I, Richard P. Dealy, Executive Vice President and Chief Financial Officer of Pioneer Natural Resources Company (the "Company"), hereby certify that the accompanying Annual Report on Form 10-K for the year ended December 31, 2017 and filed with the Securities and Exchange Commission pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report") by the Company fully complies with the requirements of that section.

I further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

	/s/ Richard P. Dealy
Name:	Richard P. Dealy, Executive Vice President and Chief Financial Officer
Date:	February 20, 2018

EXHIBIT 95.1

Mine Safety Disclosure

The following disclosures are provided pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") and Item 104 of Regulation S-K, which requires certain disclosures by companies required to file periodic reports under the Securities Exchange Act of 1934, as amended, that operate mines regulated under the Federal Mine Safety and Health Act of 1977 (the "Mine Act").

Whenever the Federal Mine Safety and Health Administration ("MSHA") believes a violation of the Mine Act, any health or safety standard or any regulation has occurred, it may issue a citation which describes the alleged violation and fixes a time within which the U.S. mining operator must abate the alleged violation. In some situations, such as when MSHA believes that conditions pose a hazard to miners, MSHA may issue an order removing miners from the area of the mine affected by the condition until the alleged hazards are corrected. When MSHA issues a citation or order, it generally proposes a civil penalty, or fine, as a result of the alleged violation, that the operator is ordered to pay. Citations and orders can be contested and appealed, and as part of that process, are often reduced in severity and amount, and are sometimes dismissed. The number of citations, orders and proposed assessments vary depending on the size and type (underground or surface) of the mine as well as by the MSHA inspector(s) assigned.

The table below sets forth for the year ended December 31, 2017 for each sand mine of Pioneer Natural Resources Company or its subsidiaries (the "Company"), (i) the total number of citations for violations of mandatory health or safety standards that could significantly and substantially contribute to the cause and effect of mine safety or health hazard under section 104 of the Mine Act for which the operator received a citation from MSHA; (ii) the total number of orders issued under section 104(b) of the Mine Act; (iii) the total number of citations and orders for unwarrantable failure of the mine operator to comply with mandatory health or safety standards under section 104(d) of the Mine Act; (iv) the total number of flagrant violations under section 110(b)(2) of the Mine Act; (v) the total number of imminent danger orders issued under section 107(a) of the Mine Act; (vi) the total dollar value of proposed assessments from MSHA; (vii) the total number of mining-related fatalities; (viii) whether or not the mine has received any notices from MSHA of a pattern of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of mine health or safety hazards under section 104(e) of the Mine Act; (ix) whether or not the mine has received any notices from MSHA regarding the potential to have a pattern of violations as referenced in (viii) above; and (x) the total number of pending legal actions before the Federal Mine Safety and Health Review Commission as of December 31, 2017 involving such mine, as well as the aggregate number of legal actions instituted and the aggregate number of legal actions resolved during the reporting period. The MSHA citations, orders and assessments are those initially issued or proposed by MSHA. They do not reflect any subsequent changes in the level of severity of a citation or order or the value of an assessment that may occur as a result of proceedings conducted in accordance with MSHA rules.

Mine/MSHA Identification Number(1)	Section 104 S&S Citations	Section 104(b) Orders	Section 104(d) Citations and Orders	Section 110(b)(2) Violations	Section 107(a) Orders	Total Dollar Value of Proposed Assessments	Mining Related Fatalities	Received Notice of Pattern of Violations under Section 104(e) (yes/no)	Received Notice of Potential to have Pattern under Section 104(e) (yes/no)	Legal Actions Pending as of Last Day of Period	Legal Actions Initiated During Period	Legal Actions Resolved During Period
Colorado Springs Operation / 0503295	10	—	—	—	—	$ 4,348	—	No	No	—	—	—
Voca Pit and Plant / 4101003	8	—	—	—	—	$ 1,027	—	No	No	—	—	—
Voca West / 4103618	5	—	—	—	—	$ 635	—	No	No	—	—	—
Brady Plant / 4101371	4	—	—	—	—	$ 596	—	No	No	—	—	—
Millwood Operation / 3301355	2	—	—	—	—	$ 254	—	No	No	—	—	—

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(1) The definition of mine under section three of the Mine Act includes the mine, as well as other items used in, or to be used in, or resulting from, the work of extracting minerals, such as land, structures, facilities, equipment, machines, tools and minerals preparation facilities. Unless otherwise indicated, any of these other items associated with a single mine have been aggregated in the totals for that mine. MSHA assigns an identification number to each mine and may or may not assign separate identification numbers to related facilities such as preparation facilities.

EXHIBIT 99.1

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 31, 2018

Mr. Kerry D. Scott
Pioneer Natural Resources Company
5205 N. O'Connor Boulevard, Suite 200
Irving, Texas 75039-3746

Dear Mr. Scott:

In accordance with your request, we have audited the estimates prepared by Pioneer Natural Resources Company (Pioneer), as of December 31, 2017, of the proved reserves and future revenue to the Pioneer interest in certain oil and gas properties located in Colorado, New Mexico, North Dakota, and Texas. It is our understanding that the proved reserves estimates shown herein constitute all of the proved reserves owned by Pioneer. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, future net revenue, and the present value of such future net revenue, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves and future revenue have been prepared in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for Pioneer's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth Pioneer's estimates of the net reserves and future net revenue, as of December 31, 2017, for the audited properties:

	Net Reserves			Future Net Revenue (M$)	
Category	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	437,666	188,106	1,460,841	15,150,654	8,233,021
Proved Developed Non-Producing	4,698	1,327	168,610	406,015	160,313
Proved Undeveloped	40,525	21,063	122,429	1,322,897	482,573
Total Proved	482,889	210,497	1,751,880	16,879,566	8,875,907

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

When compared on a lease-by-lease basis, some of the estimates of Pioneer are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of Pioneer's reserves and future revenue are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by Pioneer in preparing the December 31, 2017, estimates of reserves and future revenue, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by Pioneer.

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Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk. Pioneer's estimates do not include probable or possible reserves that may exist for these properties, nor do they include any value for undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Prices used by Pioneer are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2017. For oil and NGL volumes, the average West Texas Intermediate spot price of $51.34 per barrel is adjusted by property group for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.976 per MMBTU is adjusted by property group for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $48.63 per barrel of oil, $19.63 per barrel of NGL, and $2.60 per MCF of gas.

Operating costs used by Pioneer are based on historical operating expense records. For the nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs for the operated properties are limited to direct lease- and field-level costs and Pioneer's estimate of the portion of its headquarters general and administrative overhead (G&A) expenses necessary to operate the properties. Pioneer's estimate of G&A expenses is included at the field area level. Capital costs used by Pioneer are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Abandonment costs used are Pioneer's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Abandonment costs are included for economic wells and shut-in wells; these costs are not included for wells that are currently producing below their economic limit. Operating, capital, and abandonment costs are not escalated for inflation.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, estimates of Pioneer and NSAI are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Pioneer, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of major properties making up approximately 77 percent of Pioneer's total proved reserves and accounting for approximately 91 percent of the present worth for those reserves. These major properties are located in the Permian Basin, New Mexico and Texas, and are grouped into Permian vertical, Spraberry horizontal, and Southern Wolfcamp Asset Team (SWAT) horizontal field areas. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by Pioneer with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of Pioneer's overall reserves management processes and practices.

We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to establish the conclusions set forth herein. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

Supporting data documenting this audit, along with data provided by Pioneer, are on file in our office. The technical person primarily responsible for conducting this audit meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. G. Lance Binder, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1983 and has over 5 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III
By:
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

/s/ G. Lance Binder
By:
G. Lance Binder, P.E. 61794 Executive Vice President

Date Signed: January 31, 2018

GLB:CLH