EQT Corp
Form 10-K
February 14, 2019

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

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

or

FOR THE TRANSITION PERIOD FROM ___________ TO __________

COMMISSION FILE NUMBER 001-03551

EQT CORPORATION
(Exact name of registrant as specified in its charter)

PENNSYLVANIA (State or other jurisdiction of incorporation or organization)	25-0464690 (IRS Employer Identification No.)
625 Liberty Avenue, Suite 1700 Pittsburgh, Pennsylvania (Address of principal executive offices)	15222 (Zip Code)

Registrant’s telephone number, including area code: (412) 553-5700

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

Title of each class	Name of each exchange on which registered
Common Stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No ___

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes X 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, smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer X	Accelerated filer ___
Non-accelerated filer ___ (Do not check if a smaller reporting company)	Smaller reporting company ___
	Emerging growth 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 X

The aggregate market value of voting stock held by non-affiliates of the registrant as of June 30, 2018: $14.5 billion

The number of shares (in thousands) of common stock outstanding as of January 31, 2019: 254,762

DOCUMENTS INCORPORATED BY REFERENCE

The Company's definitive proxy statement relating to the 2019 annual meeting of shareholders will be filed with the Securities and Exchange Commission within 120 days after the close of the Company's fiscal year ended December 31, 2018 and is incorporated by reference in Part III to the extent described therein.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

Commonly Used Terms

Appalachian Basin – the area of the United States composed of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains.

basis – when referring to commodity pricing, the difference between the futures price for a commodity and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location, transportation capacity availability and contract pricing.

British thermal unit – a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.

collar – a financial arrangement that effectively establishes a price range for the underlying commodity. The producer bears the risk and benefit of fluctuation between the minimum (floor) price and the maximum (ceiling) price.

continuous accumulations – natural gas and oil resources that are pervasive throughout large areas, have ill-defined boundaries and typically lack or are unaffected by hydrocarbon-water contacts near the base of the accumulation.

development well – a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

exploratory well – a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

extension well – a well drilled to extend the limits of a known reservoir.

gas – all references to “gas” in this report refer to natural gas.

gross – “gross” natural gas and oil wells or “gross” acres equal the total number of wells or acres in which the Company has a working interest.

hedging – the use of derivative commodity and interest rate instruments to reduce financial exposure to commodity price and interest rate volatility.

horizontal drilling – drilling that ultimately is horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

horizontal wells – wells that are drilled horizontal or near horizontal to increase the length of the well bore penetrating the target formation.

multiple completion well – a well equipped to produce oil and/or gas separately from more than one reservoir. Such wells contain multiple strings of tubing or other equipment that permit production from the various completions to be measured and accounted for separately.

multi-well pad – a well pad designed to enable the development of multiple horizontal wells from a single compact surface location.

well pad - an area of land that has been cleared and leveled to enable a drilling rig to operate in the exploration and development of a natural gas or oil well.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

natural gas liquids (NGLs) – those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation or other methods in gas processing plants. Natural gas liquids include primarily ethane, propane, butane and iso-butane.

net – "net" natural gas and oil wells or "net" acres are determined by adding the fractional ownership working interests the Company has in gross wells or acres.

net revenue interest – the interest retained by the Company in the revenues from a well or property after giving effect to all third-party interests (equal to 100% minus all royalties on a well or property).

option – a contract that gives the buyer the right, but not the obligation, to buy or sell a specified quantity of a commodity or other instrument at a specific price within a specified period of time.

play – a proven geological formation that contains commercial amounts of hydrocarbons.

productive well – a well that is producing oil or gas or that is capable of production.

proved reserves – quantities of oil, natural gas, and NGLs which, by analysis of geological 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.

proved developed reserves – proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

proved undeveloped reserves (PUDs) – proved reserves that can be estimated with reasonable certainty to be recovered from new wells on undrilled proved acreage or from existing wells where a relatively major expenditure is required for completion.

reservoir – a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

service well – a well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include, among other things, gas injection, water injection and salt-water disposal.

working interest – an interest that gives the owner the right to drill, produce and conduct operating activities on a property and receive a share of any production.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

Abbreviations

ASC – Accounting Standards Codification
CFTC – Commodity Futures Trading Commission
EPA – U.S. Environmental Protection Agency
FASB – Financial Accounting Standards Board
FERC – Federal Energy Regulatory Commission
GAAP – U.S. Generally Accepted Accounting Principles
IPO – initial public offering
IRS – Internal Revenue Service
NYMEX – New York Mercantile Exchange
OTC – over the counter
SEC – Securities and Exchange Commission

Measurements

Bbl = barrel
Bcf = billion cubic feet
Bcfe = billion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
Btu = one British thermal unit
Dth = dekatherm or million British thermal units
Mbbl = thousand barrels
Mcf = thousand cubic feet
Mcfe = thousand cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
MMBtu = million British thermal units
MMcf = million cubic feet
MMcfe = million cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas
MMDth = million dekatherm
Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

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Cautionary Statements

This Annual Report on Form 10-K contains certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking and usually identified by the use of words such as “anticipate,” “estimate,” “could,” “would,” “will,” “may,” “forecast,” “approximate,” “expect,” “project,” “in “believe” and other words of similar meaning in connection with any discussion of future operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report on Form 10-K include the matters discussed in the sections captioned “Strategy” and "Outlook" in Item 1, “Business,” the section captioned “Impairment of Oil and Gas Properties and Goodwill” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” and all discussions of expectations of plans, strategies, objectives and growth and anticipated financial and operational performance of the Company and its subsidiaries, including guidance regarding the Company’s strategy to develop its Marcellus, Utica, Upper Devonian and other reserves; drilling plans and programs (including the number, type, depth, spacing, lateral lengths and location of wells to be drilled and the availability of capital to complete these plans and programs); production and sales volumes (including liquids volumes) and growth rates; production of free cash flow and the Company's ability to reduce its drilling costs and capital expenditures; the Company's ability to maximize recoveries per acre; infrastructure programs; the cost, capacity, timing of regulatory approvals; monetization transactions, including asset sales, joint ventures or other transactions involving the Company’s assets; acquisition transactions; the Company’s ability to achieve the anticipated synergies, operational efficiencies and returns from its acquisition of Rice Energy Inc.; the Company's ability to achieve the anticipated operational, financial and strategic benefits of its spin-off of Equitrans Midstream Corporation (Equitrans Midstream); the timing and structure of any dispositions of the Company's approximately 19.9% interest in Equitrans Midstream, and the planned use of the proceeds from any such dispositions; natural gas prices, changes in basis and the impact of commodity prices on the Company's business; reserves, including potential future downward adjustments and reserve life; potential future impairments of the Company's assets; projected capital expenditures and capital contributions; the amount and timing of any repurchases of the Company's common stock including whether the Company will institute a share repurchase program; dividend amounts and rates; liquidity and financing requirements, including funding sources and availability; hedging strategy; the effects of government regulation and litigation and tax position. The forward-looking statements included in this Annual Report on Form 10-K involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The Company has based these forward-looking statements on current expectations and assumptions about future events, taking into account all information currently available to the Company. While the Company considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties, many of which are difficult to predict and beyond the Company’s control. The risks and uncertainties that may affect the operations, performance and results of the Company’s business and forward-looking statements include, but are not limited to, those set forth under Item 1A, “Risk Factors,” and elsewhere in this Annual Report on Form 10-K, and the other documents the Company files from time to time with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company does not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development program. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

In reviewing any agreements incorporated by reference in or filed with this Annual Report on Form 10-K, please remember such agreements are included to provide information regarding the terms of such agreements and are not intended to provide any other factual or disclosure information about the Company. The agreements may contain representations and warranties by the Company, which should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to such agreements should those statements prove to be inaccurate. The representations and warranties were intended to be relied upon solely by the applicable party to such agreement and were made only as of the date of the relevant agreement or such other date or dates as may be specified in such agreement and are subject to more recent developments. Accordingly, these representations and warranties alone may not describe the actual state of affairs of the Company or its affiliates as of the date they were made or at any other time and should not be relied upon as statements of fact.

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PART I

Item 1. Business

General

EQT Corporation (EQT or the Company) is a natural gas production company with emphasis in the Appalachian Basin and operations throughout Pennsylvania, West Virginia and Ohio. EQT is the largest producer of natural gas in the United States, based on average daily sales volumes, with 21.8 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 1.4 million gross acres, including approximately 1.1 million gross acres in the Marcellus play, many of which have associated deep Utica or Upper Devonian drilling rights, and approximately 0.1 million gross acres in the Ohio Utica play as of December 31, 2018.

Strategy

The Company seeks to be the premier producer of environmentally friendly, reliable, low-cost natural gas, while maximizing the long-term value of its assets through operational efficiency and a culture of sustainability. To accomplish these objectives and deliver value to its stakeholders, the Company's strategic priorities include focusing on reducing costs, improving operational and capital efficiency, consistently delivering volumes and prioritizing the return of capital to shareholders while strengthening the Company's balance sheet. The Company intends to achieve mid-single digit year-over-year production growth combined with substantial and sustainable free cash flow by executing on its plan, with a stable operating cadence which is expected to result in higher capital efficiency.

The Company believes the long-term outlook for its business is favorable due to the Company’s substantial resource base, financial strength, and its commitment to capital discipline and operational efficiencies. The Company believes the combination of these factors provide it with an opportunity to exploit and develop its acreage and reserves and maximize efficiency through economies of scale. The Company has a significant contiguous acreage position in the core of the Marcellus and Utica shales which the Company believes will allow it to realize operational efficiencies and improve overall returns. The Company believes that it is a technology leader in horizontal drilling and completion activities in the Appalachian Basin and continues to improve its operations through the use of new technologies and a company-wide focus on efficiency. Development of multi-well pads in conjunction with longer laterals, optimized well spacing, and completion techniques allow the Company to maximize development efficiencies while reducing the overall environmental surface footprint of its drilling operations.

Key Events in 2018

- The Company achieved annual sales volumes of 1,488 Bcfe and average daily sales volumes of 4,076 MMcfe/d. Adjusted for the impact of the 2018 Divestitures, as explained below, total annual sales volumes were 1,447 Bcfe or 3,964 MMcfe/d.

- On June 19, 2018, the Company sold its non-core Permian Basin assets located in Texas for net proceeds of $56.9 million (the Permian Divestiture). The assets sold in the Permian Divestiture included approximately 970 productive wells with net production of approximately 20 MMcfe per day at the time of sale, approximately 350 miles of low-pressure gathering lines and 26 compressors.

- On July 18, 2018, the Company sold approximately 2.5 million non-core, net acres in the Huron play for net proceeds of $523.6 million (the Huron Divestiture). The assets sold in the Huron Divestiture included approximately 12,000 productive wells with current net production of approximately 200 MMcfe per day, approximately 6,400 miles of low-pressure gathering lines and 59 compressor stations. The Company retained the deep drilling rights across the divested acreage.

- On November 12, 2018, the Company completed the Separation and Distribution of Equitrans Midstream Corporation (Equitrans Midstream), as explained below under “Separation and Distribution.”

Outlook

In 2019, the Company expects to spend approximately $1.5 billion for reserve development, approximately $0.2 billion for land and lease acquisitions, approximately $0.1 billion for capitalized overhead and approximately $0.1 billion for other production infrastructure. The Company plans to spud approximately 134 gross wells (126 net), including 91 Marcellus wells in Pennsylvania, 15 Marcellus wells in West Virginia and 28 Ohio Utica gross wells (20 net). Estimated sales volumes are expected to be 1,470 to 1,510 Bcfe for 2019. The 2019 drilling program is expected to support a 5% increase in sales volume in 2020 over

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the Company's 2019 expected sales volumes. The 2019 capital investment plan is expected to be funded by cash generated from operations.

The Company’s revenues, earnings, liquidity and ability to grow are substantially dependent on the prices it receives for, and the Company’s ability to develop its reserves of, natural gas, oil and NGLs. Due to the volatility of commodity prices, the Company is unable to predict future potential movements in the market prices for natural gas, and NGLs at the Company's ultimate sales points and thus cannot predict the ultimate impact of prices on its operations. Changes in natural gas, NGLs and oil prices could affect, among other things, the Company's development plans, which would increase or decrease the pace of the development and the level of the Company's reserves, as well as the Company's revenues, earnings or liquidity. Lower prices could also result in non-cash impairments in the book value of the Company’s oil and gas properties or other long lived intangible assets or downward adjustments to the Company’s estimated proved reserves. Any such impairment and/or downward adjustment to the Company’s estimated reserves could potentially be material to the Company. See "Impairment of Oil and Gas Properties and Goodwill" and “Critical Accounting Policies and Estimates” included in Item 7, "Management’s Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of the Company’s accounting policies and significant assumptions related to accounting for oil and gas producing activities and the Company's policies and processes with respect to impairment reviews for proved and unproved property and goodwill.

Separation and Distribution

On November 12, 2018, EQT completed the previously announced separation of its midstream business, which was composed of the separately operated natural gas gathering, transmission and storage, and water services businesses of EQT, from its upstream business, which is composed of the natural gas, oil and natural gas liquids development, production and sales and commercial operations of the Company (the Separation). The Separation was effected by the transfer of the midstream business from EQT to Equitrans Midstream and the distribution of 80.1% of the outstanding shares of Equitrans Midstream common stock to EQT's shareholders (the Distribution). EQT's shareholders of record as of the close of business on November 1, 2018 (the Record Date) received 0.80 shares of Equitrans Midstream common stock for every one share of EQT common stock held as of the close of business on the Record Date. EQT retained 19.9% of the outstanding shares of Equitrans Midstream common stock.

As a result of the Distribution, Equitrans Midstream is now an independent public company listed under the ticker symbol “ETRN” on the New York Stock Exchange (NYSE). The Company’s common stock is listed under the symbol “EQT” on the NYSE.

The Company plans to dispose of all of its retained Equitrans Midstream common stock, which may include dispositions through one or more subsequent exchanges for debt or a sale of its shares for cash. The Company expects to use the proceeds from any dispositions of its retained Equitrans Midstream common stock to reduce the Company's debt.

Segment and Geographical Information

The Company's operations consist of one reportable segment. The Company has a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. The Company measures financial performance as a single enterprise and not on an area-by-area basis. Substantially all of the Company’s assets and operations are located in the Appalachian Basin.

Proved Reserves

The Company’s proved reserves increased 2% in 2018, or 11% when adjusted for the impact of the Huron Divestiture and Permian Divestiture (collectively, the 2018 Divestitures). The Company's Marcellus assets constituted approximately 19.1 Tcfe of the Company's total proved reserves as of December 31, 2018 and increased 13% as compared to December 31, 2017. The Company’s Marcellus assets constituted approximately 87% of the Company's total proved reserves by volume as of December 31, 2018. As of December 31, 2018, the Company’s proved reserves were as follows:

(Bcfe)	Marcellus	Upper Devonian	Ohio Utica	Other	Total
Proved Developed	9,625	915	898	112	11,550
Proved Undeveloped	9,464	92	711	—	10,267
Total Proved Reserves	19,089	1,007	1,609	112	21,817

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The Company’s natural gas wells generally have long reserve lives. Assuming that future annual production from these reserves is consistent with 2019 production guidance, the remaining reserve life of the Company’s total proved reserves, as calculated by dividing total proved reserves by 2019 production volumes guidance, is approximately 15 years.

The Company invested approximately $2,255.0 million on reserve development during 2018, with total sales volumes of 1,488 Bcfe, an increase of 68% over the previous year. The Company drilled approximately 153 gross wells (133 net), including 105 Marcellus gross wells in Pennsylvania (99 net), 5 Upper Devonian wells in Pennsylvania, 12 Marcellus wells in West Virginia and 31 Ohio Utica gross wells (17 net). During the past three years, the Company’s capital expenditures for reserve development were:

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Horizontal Marcellus*	$1,895	$1,137	$559
Ohio Utica	360	50	58
Other	—	21	6
Total	$2,255	$1,208	$623

* Includes Upper Devonian formations.

The Company sells natural gas and NGLs to marketers, utilities and industrial customers within its operational footprint and in markets that are accessible through the Company's current transportation portfolio. The Company has access to approximately 2.9 Bcf per day of firm contractual pipeline takeaway capacity and 0.6 Bcf per day of firm processing capacity. The Company has also committed to an initial 1.29 Bcf per day of firm capacity on the Mountain Valley Pipeline (MVP) which is expected to be placed in-service in the fourth quarter of 2019.

Markets and Customers

No single customer accounted for more than 10% of EQT's total operating revenues for 2018, 2017 and 2016.

Natural Gas Sales: The Company’s produced natural gas is sold to marketers, utilities and industrial customers located in the Appalachian Basin and in the markets that are accessible through the Company's current transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States as well as Canada. Natural gas is a commodity and therefore the Company typically receives market-based pricing. The market price for natural gas in the Appalachian Basin is lower relative to the price at Henry Hub, Louisiana (the location for pricing NYMEX natural gas futures) as a result of the increased supply of natural gas in the Appalachian Basin. In order to protect cash flow from undue exposure to the risk of changing commodity prices, the Company hedges a portion of its forecasted natural gas production, most of which is hedged at NYMEX natural gas prices. The Company’s hedging strategy and information regarding its derivative instruments is set forth under the heading “Commodity Risk Management” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” in Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” and in Notes 1 and 5 to the Consolidated Financial Statements.

NGLs Sales: The Company primarily sells NGLs processed from its own gas production. In its Appalachian operations, the Company primarily contracts with MarkWest Energy Partners, L.P. (MarkWest) to process natural gas in order to extract the heavier hydrocarbon stream (consisting predominately of ethane, propane, iso-butane, normal butane and natural gasoline) primarily from the Company’s produced gas. The Company also contracts with MarkWest to market a portion of the Company's NGLs. The Company also has contractual arrangements with Williams Ohio Valley Midstream LLC to process natural gas and market a portion of its NGLs on behalf of the Company in its

Appalachian operations.

The following table presents the average sales price on a per Mcfe basis to EQT for sales of produced natural gas, NGLs and oil, with and without cash settled derivatives.

	For the Years Ended December 31,		
	2018	2017	2016
Average sales price per Mcfe sold (excluding cash settled derivatives)	$3.15	$2.98	$1.99
Average sales price per Mcfe sold (including cash settled derivatives)	$3.01	$3.04	$2.47

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In addition, price information for all products is included in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” under the caption “Average Realized Price Reconciliation,” and incorporated herein by reference.

Natural Gas Marketing: EQT Energy, LLC (EQT Energy), the Company's indirect wholly owned marketing subsidiary, provides marketing services and contractual pipeline capacity management primarily for the benefit of the Company. EQT Energy also engages in risk management and hedging activities on behalf of the Company, the objective of which is to limit the Company’s exposure to shifts in market prices.

Competition

Other natural gas producers compete with the Company in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and NGLs and the securing of services, labor, equipment and transportation required to conduct operations. The Company's competitors include independent oil and gas companies, major oil and gas companies and individual producers, operators and marketing companies.

Regulation

Regulation of the Company’s Operations

The Company’s exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of fluids and materials incidental to oil and gas operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances. These regulations and any delays in obtaining related authorizations may affect the costs and timing of developing the Company’s natural gas resources.

The Company’s operations are also subject to conservation and correlative rights regulations, including the regulation of the size of drilling and spacing units or field rule units; setbacks; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of natural gas properties. Kentucky, Ohio, Virginia and, for Utica or other deep wells, West Virginia allow the statutory pooling or unitization of tracts to facilitate development and exploration. In West Virginia, the Company must rely on voluntary pooling of lands and leases for Marcellus and Upper Devonian acreage. In 2013, the Pennsylvania legislature enacted lease integration legislation, which authorizes joint development of existing contiguous leases. In addition, state conservation and oil and gas laws generally limit the venting or flaring of natural gas. Various states also impose certain regulatory requirements to transfer wells to third parties or discontinue operations in the event of divestitures by the Company.

The Company's gathering operations are subject to various types of federal and state environmental laws and local zoning ordinances, including air permitting requirements for compressor station and dehydration units and other permitting requirements; erosion and sediment control requirements for compressor station and pipeline construction projects; waste management requirements and spill prevention plans for compressor stations; various recordkeeping and reporting requirements for air permits and waste management practices; compliance with safety regulations; and siting and noise regulations for compressor stations. These regulations may increase the costs of operating existing pipelines and compressor stations and increase the costs of, and the time to develop, new or expanded pipelines and compressor stations.

In 2010, Congress adopted comprehensive financial reform legislation that established federal oversight and regulation of the over-the-counter derivative market and entities, such as the Company, that participate in that market. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), required the CFTC, the SEC and other regulatory agencies to promulgate rules and regulations implementing this legislation. As of the filing date of this Annual Report on Form 10-K, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including the Company, such as recordkeeping and certain reporting obligations. Other CFTC rules that may be relevant to the Company have yet to be finalized. Because significant CFTC rules relevant to natural gas hedging activities have not been adopted or implemented, it is not possible at this time to predict the extent of the impact of the regulations on the Company's hedging program or regulatory compliance obligations. The Company has experienced increased, and anticipates additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

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Regulators periodically review or audit the Company’s compliance with applicable regulatory requirements. The Company anticipates that compliance with existing laws and regulations governing current operations will not have a material adverse effect upon its capital expenditures, earnings or competitive position. Additional proposals that affect the oil and gas industry are regularly considered by Congress, the states, regulatory agencies and the courts. The Company cannot predict when or whether any such proposals may become effective or the effect that such proposals may have on the Company.

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

Natural Gas Sales and Transportation

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural 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 FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Historically, federal legislation and regulatory controls have affected the price of the natural gas the Company produces and the manner in which the Company markets its production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of the Company's sales of its own production. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties of over $1 million per day for each violation and disgorgement of profits associated with any violation. While the Company's production activities have not been regulated by the FERC as a natural gas company under the NGA, the Company is required to report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. In addition, Congress may enact legislation or the FERC may adopt regulations that may subject certain of the Company's otherwise non-FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject the Company to civil penalty liability.

The CFTC also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that the Company undertakes, the Company is thus required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the CFTC. The CFTC also holds substantial enforcement authority, including the ability to assess civil penalties.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which the Company may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that the Company produces, as well as the revenues the Company receives for sales of natural gas and release of its natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. The FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, the Company cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can the Company determine what effect, if any, future regulatory changes might have on the Company's natural gas related activities.

Under the FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities are done on a case-by-case basis. To the extent that the FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, and, depending on the scope of that decision, the Company's costs of transporting gas to point of sale locations may increase. The Company believes that the third-party natural gas pipelines on which its gas is gathered meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas

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company. However, the distinction between the FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of those gathering facilities are subject to change based on future determinations by the FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Oil and NGLs Price Controls and Transportation Rates

Sales prices of oil and NGLs are not currently regulated and are made at market prices. The Company's sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission (FTC) prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of over $1 million per day per violation. The Company's sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price the Company receives from the sale of these products may be affected by the cost of transporting the products to market. Some of the Company's transportation of oil, natural gas and NGLs is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of crude oil and NGLs transportation rates may tend to increase the cost of transporting crude oil and NGLs by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. The Company is not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from the Company's crude oil producing operations.

Environmental, Health and Safety Regulation

The business operations of the Company are also subject to numerous stringent federal, state and local environmental, health and safety laws and regulations pertaining to, among other things, the release, emission or discharge of materials into the environment; the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes); the safety of employees and the general public; pollution; site remediation; and preservation or protection of human health and safety, natural resources, wildlife and the environment. The Company must take into account environmental, health and safety regulations in, among other things, planning, designing, constructing, operating and abandoning wells and related facilities. Violations of these laws can result in substantial administrative, civil and criminal penalties. These laws and regulations may require the acquisition of permits before drilling or other regulated activity commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas or areas with endangered or threatened species restrictions, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits, establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with applicable laws and regulations. In addition, these laws and regulations may restrict the rate of production.

Moreover, the trend has been for stricter regulation of activities that have the potential to affect the environment. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, federal agencies, the states, local governments, and the courts. The Company cannot predict when or whether any such proposals may become effective. Therefore, the Company is unable to predict the future costs or impact of compliance. The regulatory burden on the industry increases the cost of doing business and affects profitability. The

Company has established procedures, however, for the ongoing evaluation of its operations to identify potential environmental exposures and to track compliance with regulatory policies and procedures.

The following is a summary of the more significant existing environmental and occupational health and workplace safety laws and regulations, as amended from time to time, to which the Company's business operations are subject and for which compliance may have a material adverse impact on the Company's financial condition, earnings or cash flows.

Hazardous Substances and Waste Handling. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the “Superfund” law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous

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substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In addition, despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, the Company generates materials in the course of its operations that may be regulated as hazardous substances based on their characteristics; however, the Company is unaware of any liabilities arising under CERCLA for which the Company may be held responsible that would materially and adversely affect the Company.

The Resource Conservation and Recovery Act (RCRA) and analogous state laws establish detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA, or state agencies under RCRA's less stringent nonhazardous solid waste provisions, or under state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019, for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. The EPA would be required to complete any rulemaking revising the Subtitle D criteria by 2021. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in the Company's costs to manage and dispose of generated wastes, which could have a material adverse effect on the Company's results of operations and financial condition.

The Company currently owns, leases, or operates numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although the Company believes that it has utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by the Company, or on, under or from other locations, including offsite locations, where such substances have been taken for recycling or disposal. In addition, some of the Company's properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under the Company's control. The Company is able to control directly the operation of only those wells with respect to which the Company acts or has acted as operator. The failure of a prior owner or operator to comply with applicable environmental regulations may, in certain circumstances, be attributed to the Company as current owner or operator under CERCLA. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Company could be required to undertake response or corrective measures, regardless of fault, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or waste pit closure operations to prevent future contamination.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act (CWA), and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state equivalent agency. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (Corps). In September 2015, the EPA and the Corps issued a final rule defining the scope of the EPA's and the Corps' jurisdiction over waters of the United States (WOTUS), but several legal challenges to the rule followed, and the WOTUS rule was stayed nationwide in October 2015 pending resolution of the court challenges. The EPA and the Corps proposed a rule in June 2017 to repeal the WOTUS rule and announced their intent to issue a new rule defining the CWA's jurisdiction. In January 2018, the U.S. Supreme Court issued a decision finding that jurisdiction to hear challenges to the WOTUS rule resides with the federal district courts; consequently, the previously filed district court cases were allowed to proceed, resulting in a patchwork of implementation in some states and stays in others. Following the U.S. Supreme Court's decision, the EPA and the Corps issued a final rule in January 2018 staying implementation of the WOTUS rule for two years while the agencies reconsider the rule, but a federal judge barred the agencies' suspension of the rule in August 2018. Subsequently, various district court decisions revived the WOTUS rule in 22 states, the District of Columbia, and the U.S. territories, and have enjoined implementation of the rule in 28 states. In December 2018, the EPA and the Corps released a proposal to redefine the definition of WOTUS. The new proposed definition narrows the scope of waters that are covered as jurisdictional under the WOTUS rule. This proposed definition may be subject to an expanded comment period and future litigation. As a result, future implementation of the WOTUS 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, which could delay the development of the Company's natural gas and oil projects. Also, pursuant to these laws and regulations, the Company may be required to obtain and maintain approvals or permits for the discharge of wastewater or stormwater and to develop and implement spill prevention, control and countermeasure (SPCC) plans in connection with on-site storage of significant quantities of oil. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Air Emissions. The federal Clean Air Act (CAA) and comparable state laws regulate the emission of air pollutants from many sources, such as, for example, tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require the Company to obtain pre approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants, the costs of which could be significant. The need to obtain permits has the potential to delay the development of the Company's oil and natural gas projects. Over the next several years, the Company may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard (NAAQS) for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards and completed attainment/non-attainment designations in July 2018. States are expected to implement more stringent permitting requirements as a result of the final rule, which could apply to the Company's operations. While the EPA has determined that all counties in which the Company operates are in attainment with the new ozone standards, these determinations may be revised in the future. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new facilities or modify existing facilities in these newly designated non-attainment areas. Compliance with these more stringent standards and other environmental regulations could delay or prohibit the Company's ability to obtain permits for its operations or require the Company's to install additional pollution control equipment, the costs of which could be significant.

Climate Change and Regulation of “Greenhouse Gas” Emissions. In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (GHG) present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration (PSD) construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rulemakings could adversely affect our operations and restrict or delay the Company's ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of the Company's operations. For example, in December 2015, the EPA finalized rules that added new sources to the scope of the GHG monitoring and reporting rule. These new sources include gathering and boosting facilities as well as completions and workovers from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. These changes to the EPA’s GHG emissions reporting rule could result in increased compliance costs.

In June 2016, the EPA finalized new regulations that establish New Source Performance Standards (NSPS), known as Subpart OOOOa, for methane and volatile organic compounds (VOC) from new and modified oil and natural gas production and natural gas processing and transmission facilities. While the EPA has taken several steps to delay implementation of its methane standards, to date the courts have generally ruled that such attempts have been unlawful. In September 2018, the EPA proposed amendments to the 2016 Subpart OOOOa standards that would reduce the 2016 rule’s fugitive emissions monitoring requirements and expand exceptions to pneumatic pump requirements, among other changes. Various industry and environmental groups have separately challenged both the methane requirements and the EPA’s attempts to delay the implementation of the rule. In addition, in April 2018, several states filed a lawsuit seeking to compel the EPA to issue methane performance standards for existing sources in the oil and natural gas source category. As a result of the actions described above, the Company cannot predict with certainty the scope of any final methane regulations or the costs for complying with federal methane regulations.

At the state level, several states have proceeded with regulation targeting GHG emissions. For example, in June 2018, the Pennsylvania Department of Environmental Protection (PADEP) released revised versions of GP-5 and GP-5A, Pennsylvania’s general air permits applicable to processing plants and well site operations, among other facilities. These permits apply to new or modified sources constructed on or after August 8, 2018, with emissions below certain specified thresholds. GP-5 and GP-5A impose “best available technology” (BAT) standards, which are in addition to, and in many cases more stringent than, the federal NSPS. These BAT standards include a 200 ton per year limit on methane emissions, above which a BAT requirement for methane emissions control applies. Moreover, in December 2018, the PADEP released a draft proposed rulemaking for emissions of VOCs and other pollutants for existing sources. State regulations such as these could impose increased compliance costs on the Company's operations.

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While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of federal legislation in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting GHGs. While Pennsylvania is not currently a member of the Regional Greenhouse Gas Initiative (RGGI), a multi-state regional cap and trade program comprised of several Eastern U.S. states, it is possible that it may join RGGI in the future. This could result in increased operating costs if the Company's operations are required to purchase emission allowances.

On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to an international climate change agreement in Paris, France, that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets (Paris Agreement). The Paris Agreement was signed by the United States in April 2016 and entered into force on November 4, 2016; however, the Paris Agreement does not impose any binding obligations on its participants. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' intent 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 reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact the Company's business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company's equipment and operations could require the Company to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could also adversely affect demand for the oil and natural gas the Company produces and lower the value of its reserves.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of finding for the energy sector. Moreover, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While the Company cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities.

Finally, it should be noted that a number of 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 have the potential to cause physical damage to the Company's assets or affect the availability of water and thus could have an adverse effect on the Company's exploration and production operations.

Hydraulic Fracturing Activities. Vast quantities of natural gas deposits exist in shale and other formations. It is customary in the Company's industry to recover natural gas from these shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into a shale gas formation. These deeper formations are geologically separated and isolated from fresh ground water supplies by overlying rock layers. The Company's well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers. To assess water sources near the Company's drilling locations, the Company conducts baseline and, as appropriate, post-drilling water testing at all water wells within at least 2,500 feet of the Company's drilling pads.

Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (SDWA) over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding such activities. The EPA also finalized rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

Certain governmental reviews have been conducted or are underway that focus on the environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water

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withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Because the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, in January 2016, the PADEP issued new rules establishing stricter disposal requirements for wastes associated with hydraulic fracturing activities, which include, among other things, a prohibition on the use of centralized impoundments for the storage of drill cuttings and waste fluids. Further, these rules include requirements relating to storage tank security, secondary containment for storage vessels, construction rules for gathering lines and horizontal drilling under streams, and temporary transport lines for freshwater and wastewater. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where the Company operates, the Company could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from constructing wells.

Occupational Safety and Health Act. The Company is also subject to the requirements of the federal Occupational Safety and Health Act (OSHA), as amended, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in the Company's operations and that this information be provided to employees, state and local government authorities, and citizens.

Endangered Species Act. The federal Endangered Species Act (ESA) provides for the protection of endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service (FWS), may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas for natural gas and oil development. Further, the designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause the Company to incur increased costs arising from species protection measures or could result in limitations on the Company's exploration and production activities that could have an adverse impact on the Company's ability to develop and produce reserves.

See Note 15 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

Employees

The Company and its subsidiaries had 863 employees as of January 31, 2019; none are subject to a collective bargaining agreement.

Availability of Reports

The Company makes certain filings with the SEC, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through its website, http://www.eqt.com, as soon as reasonably practicable after they are filed with, or furnished to, the SEC. The filings are also available by accessing the SEC's website at http://www.sec.gov.

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Composition of Operating Revenues

Presented below are operating revenues for each class of products and services.

	For the Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
Operating revenues:			
Sales of natural gas, oil and NGLs	$4,695,519	$2,651,318	$1,594,997
Net marketing services and other	40,940	49,681	41,048
(Loss) gain on derivatives not designated as hedges	(178,591)	390,021	(248,991)
Total operating revenues	$4,557,868	$3,091,020	$1,387,054

Jurisdiction and Year of Formation

The Company is a Pennsylvania corporation formed in 2008 in connection with a holding company reorganization of the former Equitable Resources, Inc.

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Item 1A. Risk Factors

In addition to the other information contained in this Annual Report on Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. Please note that additional risks not presently known to us or that are currently considered immaterial may also have a negative impact on our business and operations. If any of the events or circumstances described below actually occurs, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline.

Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect upon our revenue, profitability, future rate of growth, liquidity and financial position.

Our revenue, profitability, future rate of growth, liquidity and financial position depend upon the prices for natural gas, NGLs and oil. The prices for natural gas, NGLs and oil have historically been volatile, and we expect this volatility to continue in the future. The prices are affected by a number of factors beyond our control, which include:

- weather conditions and seasonal trends;
- the domestic and foreign supply of and demand for natural gas, NGLs and oil;
- prevailing prices on local price indexes in the areas in which we operate and expectations about future commodity prices;
- national and worldwide economic and political conditions;
- new and competing exploratory finds of natural gas, NGLs and oil;
- changes in U.S. exports of natural gas, NGLs and/or oil;
- the effect of energy conservation efforts;
- the price, availability and acceptance of alternative fuels;
- the availability, proximity, capacity and cost of pipelines, other transportation facilities, and gathering, processing and storage facilities and other factors that result in differentials to benchmark prices;
- technological advances affecting energy consumption and production;
- the actions of the Organization of Petroleum Exporting Countries;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others;
- the cost of exploring for, developing, producing and transporting natural gas, NGLs and oil;
- the level of global inventories;
- risks associated with drilling, completion and production operations; and
- domestic, local and foreign governmental regulations, tariffs and taxes, including environmental and climate change regulation.

The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $6.88 per MMBtu to a low of $2.48 per MMBtu from January 1, 2018 through December 31, 2018, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $77.41 per barrel to a low of $44.48 per barrel during the same period. In addition, the market price for natural gas in the Appalachian Basin continues to be lower relative to NYMEX Henry Hub as a result of the significant increases in the supply of natural gas in the Northeast region in recent years. Because our production and reserves predominantly consist of natural gas (approximately 94% of equivalent proved developed reserves), changes in natural gas prices have significantly greater impact on our financial results than oil prices. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, which adds further volatility to the pricing of NGLs. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, oil and NGLs at the Company's ultimate sales points and thus cannot predict the ultimate impact of prices on our operations.

Prolonged low, and/or significant or extended declines in, natural gas, NGLs and oil prices may adversely affect our revenues, operating income, cash flows and financial position, particularly if we are unable to control our development costs during periods of lower natural gas, NGLs and oil prices. Declines in prices could also adversely affect our drilling activities and the amount of natural gas, NGLs and oil that we can produce economically, which may result in our having to make significant downward adjustments to the value of our assets and could cause us to incur non-cash impairment charges to earnings in future periods. Reductions in cash flows from lower commodity prices may require us to incur additional borrowings or to reduce our capital spending, which could reduce our production and our reserves, negatively affecting our future rate of growth. Lower prices for natural gas, NGLs and oil may also adversely affect our credit ratings and result in a reduction in our borrowing capacity and access to other capital. See “Impairment of Oil and Gas Properties and Goodwill” under Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Natural gas, NGLs and oil price declines have resulted in impairment of certain of our non-core assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, including long lived intangible assets, which could materially and adversely affect our results of operations in future periods.” We are also exposed to the risk

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of non-performance by our hedge counterparties in the event that changes, positive or negative, in natural gas prices result in our derivative contracts having a positive fair value in our favor. Further, adverse economic and market conditions could negatively affect the collectability of our trade receivables and cause our hedge counterparties to be unable to perform their obligations or to seek bankruptcy protection.

Increases in natural gas, NGLs and oil prices may be accompanied by or result in increased well drilling costs, increased production taxes, increased lease operating expenses, increased volatility in seasonal gas price spreads for our storage assets and increased end-user conservation or conversion to alternative fuels. Significant natural gas price increases may subject us to margin calls on our commodity price derivative contracts (hedging arrangements, including swap, collar and option agreements and exchange-traded instruments) which would potentially require us to post significant amounts of cash collateral with our hedge counterparties. The cash collateral provided to our hedge counterparties, which is interest-bearing, is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related derivative contract. In addition, to the extent we have hedged our current production at prices below the current market price, we are unable to benefit fully from an increase in the price of natural gas.

Drilling for and producing natural gas and oil are high-risk and costly activities with many uncertainties. Our future financial position, cash flows and results of operations will depend on the success of our development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas or oil production or that we will not recover all or any portion of our investment in such wells.

Our decisions to purchase, explore or develop prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “Our proved reserves are estimates that are based upon many assumptions that may prove to be inaccurate. Any significant change in these underlying assumptions will greatly affect the quantities and present value of our reserves.” In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including limitations resulting from permitting, wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;
- shortages of or delays in obtaining equipment, rigs, materials and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- adverse weather conditions, such as flooding, droughts, freeze-offs, slips, blizzards and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in natural gas, NGLs and oil market prices;
- limited availability of financing at acceptable terms;
- ongoing litigation or adverse court rulings;
- public opposition to our operations;
- title, surface access, coal mining and right of way problems; and

•limitations in the market for natural gas, NGLs and oil.

Any of these risks can cause a delay in our development program or result in substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

Our drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our drilling locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our business strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, topography, gathering system and pipeline transportation costs and constraints, access to and availability of water sourcing and distribution systems, coordination with coal mining, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce natural gas, NGLs or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. Further, certain of the horizontal wells we intend to drill in the future may require pooling or unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to pool or unitize such leaseholds with ours, the total locations we can drill may be limited. As such, our actual drilling activities may materially differ from those presently identified.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful, may not increase our overall production levels and proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our drilling locations, see “Item 2. Properties.”

The amount and timing of actual future natural gas, NGLs and oil production is difficult to predict and may vary significantly from our estimates, which may reduce our earnings.

Because the rate of production from natural gas and oil wells, and associated NGLs, generally declines as reserves are depleted, our future success depends upon our ability to develop additional oil and gas reserves that are economically recoverable and to optimize existing well production, and our failure to do so may reduce our earnings. Additionally, a failure to effectively and efficiently operate existing wells may cause production volumes to fall short of our projections. Our drilling and subsequent maintenance of wells can involve significant risks, including those related to timing, cost overruns and operational efficiency, and these risks can be affected by the availability of capital, leases, rigs, equipment, a qualified work force, and adequate capacity for the treatment and recycling or disposal of waste water generated in our operations, as well as weather conditions, natural gas, NGLs and oil price volatility, government approvals, title and property access problems, geology, equipment failure or accidents and other factors. Drilling for natural gas and oil can be unprofitable, not only from dry wells, but from productive wells that perform below expectations or do not produce sufficient revenues to return a profit. Low natural gas, NGLs and oil prices may further limit the types of reserves that we can develop and produce economically.

Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as reserves are produced. Future natural gas, NGLs and oil production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot be certain that we will be able to find or acquire and develop additional reserves at an acceptable cost. Without continued successful development or acquisition activities, together with efficient operation of existing wells, our reserves and production, together with associated revenues, will decline as a result of our current reserves being depleted by production.

Our proved reserves are estimates that are based upon many assumptions that may prove to be inaccurate. Any significant change in these underlying assumptions will greatly affect the quantities and present value of our reserves.

Reserve engineering is a subjective process involving estimates of underground accumulations of natural gas, NGLs and oil and assumptions concerning future prices, production levels and operating and development costs, some of which are beyond our control. These estimates and assumptions are inherently imprecise, and we may adjust our estimates of proved reserves based on changes in these estimates or assumptions. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Any significant variance from our assumptions could greatly affect our estimates of reserves, the economically recoverable quantities of natural gas, NGLs and oil, the classifications of reserves based on risk of recovery and estimates of the future net cash flows. To the extent we experience a sustained period of reduced commodity prices, there is a risk that a portion of our proved reserves could be deemed uneconomic and no longer be classified as proved. Although we believe our estimates are reasonable, actual production, revenues and costs to develop reserves will likely vary from estimates and these variances could be material. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of natural gas, NGLs and oil we ultimately recover being different from our reserve estimates.

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The standardized measure of discounted future net cash flows from our proved reserves is not the same as the current market value of our estimated natural gas, NGLs and oil reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated natural gas, NGLs and oil reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the twelve month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our properties will be affected by factors such as the actual prices we receive for natural gas, NGLs and oil, the amount, timing and cost of actual production and changes in governmental regulations or taxation. The timing of both our production and our incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating the standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas, NGLs and oil industry in general.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial position and reduce our future growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our business, including well development, reserve acquisitions, exploratory activities, corporate items, leasehold maintenance and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our business plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify and execute optimal business strategies, including the appropriate corporate structure and appropriate rate of reserve development, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial position and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our business plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Our exploration and production operations have substantial capital requirements, and we may not be able to obtain needed capital or financing on satisfactory terms.

Our business is capital intensive. We make and expect to continue to make substantial capital expenditures for the development and acquisition of natural gas, NGLs and oil reserves. We typically fund our capital expenditures with existing cash and cash generated by operations and, to the extent our capital expenditures exceed our cash resources, from borrowings under our revolving credit facility and other external sources of capital. If we do not have sufficient borrowing availability under our revolving credit facility due to the current commodity price environment or otherwise, we may seek alternate debt or equity financing, sell assets or reduce our capital expenditures. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Our cash flow from operations and access to capital are subject to a number of variables, including:

•our level of proved reserves and production;
•the level of hydrocarbons we are able to produce from existing wells;
•our access to, and the cost of accessing, end markets for our production;
•the prices at which our production is sold;
•our ability to acquire, locate and produce new reserves;
•the levels of our operating expenses; and
•our ability to access the public or private capital markets or borrow under our revolving credit facility.

If our cash flows from operations or the borrowing capacity under our revolving credit facility are insufficient to fund our capital expenditures and we are unable to obtain the capital necessary for our planned capital budget or our operations, we could be required to curtail our operations and the development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, results of operations and financial position.

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As of December 31, 2018, our Senior Notes were rated “Baa3” by Moody’s Investors Services (Moody’s) with a "stable" outlook, “BBB-” by Standard & Poor’s Ratings Service (S&P) with a "stable" outlook, and “BBB-” by Fitch Ratings Service (Fitch) with a "stable" outlook. Although we are not aware of any current plans of Moody’s, S&P or Fitch to lower their respective ratings on our Senior Notes, we cannot be assured that our credit rating will not be downgraded or withdrawn entirely by a rating agency. Low prices for natural gas, NGLs and oil or an increase in the level of our indebtedness in the future may result in a downgrade in the ratings that are assigned to our Senior Notes. If any credit rating agency downgrades our ratings, particularly below investment grade, our access to the capital markets may be limited, borrowing costs and margin deposits on our derivatives would increase, we may be required to provide additional credit assurances in support of pipeline capacity contracts, the amount of which may be substantial, or we may be required to provide additional credit assurances related to joint venture arrangements or construction contracts, which could adversely affect our business, results of operations and liquidity. Investment grade refers to the quality of a company’s credit as assessed by one or more credit rating agencies. In order to be considered investment grade, a company must be rated “BBB-” or higher by S&P, “Baa3” or higher by Moody’s and “BBB-” or higher by Fitch.

Risks associated with our debt and the provisions of our debt agreements could adversely affect our business, financial position and results of operations.

As of December 31, 2018, we had approximately $5,497.4 million of debt outstanding and we may incur additional indebtedness in the future. Increases in our level of indebtedness may:

- require us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;
- limit our operating flexibility due to financial and other restrictive covenants, including restrictions on incurring additional debt, making certain investments, and paying dividends;
- place us at a competitive disadvantage compared to our competitors with lower debt service obligations;
- depending on the levels of our outstanding debt, limit our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes; and
- increase our vulnerability to downturns in our business or the economy, including declines in prices for natural gas, NGLs and oil.

Our debt agreements also require compliance with certain covenants. If the price that we receive for our natural gas, NGLs and oil production deteriorates from current levels or continues for an extended period, it could lead to reduced revenues, cash flow and earnings, which in turn could lead to a default due to lack of covenant compliance. For more information about our debt agreements, please read “Capital Resources and Liquidity” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

We are subject to financing and interest rate exposure risks.

Our business and operating results can be adversely affected by increases in interest rates or other increases in the cost of capital resulting from a reduction in our credit rating or otherwise. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for operating and capital expenditures and place us at a competitive disadvantage.

Disruptions or volatility in the financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. A significant reduction in the availability of credit could materially and adversely affect our ability to implement our business strategy and achieve favorable operating results. In addition, we are exposed to credit risk related to our revolving credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing revolving line of credit if it experiences liquidity problems.

Derivative transactions may limit our potential gains and involve other risks.

To manage our exposure to price risk, we currently and may in the future enter into derivative arrangements, utilizing commodity derivatives with respect to a portion of our future production. Such hedges are designed to lock in prices so as to limit volatility and increase the predictability of cash flow. These transactions limit our potential gains if natural gas, NGLs and oil prices rise above the price established by the hedge. In addition, derivative transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

•our production is less than expected;
•the counterparties to our derivatives contracts fail to perform on their contract obligations; or

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•an event materially impacts natural gas, NGLs or oil prices or the relationship between the hedged price index and the natural gas, NGLs or oil sales price.

We cannot be certain that any derivative transaction we may enter into will adequately protect us from declines in the prices of natural gas, NGLs or oil. Furthermore, where we choose not to engage in derivative transactions in the future, we may be more adversely affected by changes in natural gas, NGLs or oil prices than our competitors who engage in derivative transactions. Lower natural gas, NGLs and oil prices may also negatively impact our ability to enter into derivative contracts at favorable prices.

Derivative transactions also expose us to a risk of financial loss if a counterparty fails to perform under a derivative contract or enters bankruptcy or encounters some other similar proceeding or liquidity constraint. In this case, we may not be able to collect all or a significant portion of amounts owed to us by the distressed entity or entities. During periods of falling commodity prices our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

We are subject to risks associated with the operation of our wells and facilities.

Our business is subject to all of the inherent hazards and risks normally incidental to drilling for, producing, transporting and storing natural gas, NGLs and oil, such as fires, explosions, slips, landslides, blowouts, and well cratering; pipe and other equipment and system failures; delays imposed by, or resulting from, compliance with regulatory requirements; formations with abnormal or unexpected pressures; shortages of, or delays in, obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities; adverse weather conditions, such as freeze offs of wells and pipelines due to cold weather; issues related to compliance with environmental regulations; environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized releases of brine, well stimulation and completion fluids, toxic gases or other pollutants into the environment, especially those that reach surface water or groundwater; inadvertent third party damage to our assets, and natural disasters. We also face various risks or threats to the operation and security of our or third parties' facilities and infrastructure, such as processing plants, compressor stations and pipelines. Any of these risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property, equipment and natural resources, pollution or other environmental damage, loss of hydrocarbons, disruptions to our operations, regulatory investigations and penalties, suspension of our operations, repair and remediation costs, and loss of sensitive confidential information. Moreover, in the event that one or more of these hazards occur, there can be no assurance that a response will be adequate to limit or reduce damage. As a result of these risks, we are also sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business. There can be no assurance that the insurance policies we maintain to limit our liability for such losses will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices or to cover all risks. In addition, pollution and environmental risks generally are not fully insurable, and, we may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. The occurrence of an event that is not fully covered by insurance could materially adversely affect our business, results of operations, cash flows and financial position.

Cyber incidents targeting our systems or natural gas and oil industry systems and infrastructure may adversely impact our operations.

Our business and the natural gas and oil industry in general have become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications, and the maintenance of our financial and other records has long been dependent upon such technologies. We depend on this technology to record and store data, estimate quantities of natural gas, NGLs and crude oil reserves, analyze and share operating data and communicate internally and externally. Computers control nearly all of the natural gas, NGLs and oil distribution systems in the U.S., which are necessary to transport our products to market.

The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. We can provide no assurance that we will not suffer such attacks in the future. Deliberate attacks on, or unintentional events affecting, our systems or infrastructure, the systems or infrastructure of third parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in production or delivery of natural gas, NGLs and oil, difficulty in completing and settling transactions, challenges in maintaining our books and records, communication interruptions, environmental damage, personal injury, property damage, other operational disruptions and third-party liability. Further, as cyber incidents continue to evolve and cyber-attackers become more sophisticated, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. The cost to remedy an unintended dissemination of sensitive information or data may be significant. Furthermore, the continuing and evolving threat of cyber-attacks has resulted in increased regulatory focus on prevention. To the extent we face increased regulatory requirements, we may be required to expend significant additional resources to meet such requirements.

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Failure to timely develop our leased real property could result in increased capital expenditures and/or impairment of our leases.

Mineral rights are typically owned by individuals who may enter into property leases with us to allow for the development of natural gas. Such leases expire after an initial term, typically five years, unless certain actions are taken to preserve the lease. If we cannot preserve a lease, the lease terminates. 26% of our net undeveloped acres are subject to leases that could expire over the next three years. Lack of access to capital, changes in government regulations, changes in future development plans, reduced drilling activity, or the reduction in the fair value of undeveloped properties in the areas in which we operate could impact our ability to preserve, trade, or sell our leases prior to their expiration resulting in the termination and impairment of leases for properties which we have not developed.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. The likelihood of an impairment of unproved oil and gas properties increases as the expiration of a lease term approaches and drilling activity has not commenced. For the years ended December 31, 2018, 2017 and 2016, we recorded lease impairments and expirations of $279.7 million, $7.6 million and $15.7 million, respectively. Refer to Note 1 to the Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K.

We may incur losses as a result of title defects in the properties in which we invest.

Our inability to cure any title defects in our leases in a timely and cost efficient manner may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial position.

Substantially all of our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating primarily in one major geographic area.

Substantially all of our producing properties are geographically concentrated in the Appalachian Basin. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by, and costs associated with, governmental regulation, state and local political activities, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other weather related conditions, interruption of the processing or transportation of oil, natural gas or NGLs and changes in state and local laws, judicial precedents, political regimes and regulations. Such conditions could materially adversely affect our results of operations and financial position.
In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations. For example, third-parties may engage in subsurface coal and other mining operations near or under our properties, which could cause subsidence or other damage to our properties, adversely impact our drilling operations or adversely impact third-party midstream activities on which we rely. In such event, our operations may be impaired or interrupted, and we may not be able to recover the costs incurred as a result of temporary shut-ins or the plugging and abandonment of any of our wells. Furthermore, the existence of mining operations near our properties could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. These restrictions on our operations, and any similar restrictions, could cause delays or interruptions or prevent us from executing our business strategy, which could materially adversely affect our results of operations and financial position.
Further, insufficient takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas prices. The Appalachian Basin has recently experienced periods in which production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers such as us and others at times

being possibly shut in. Although additional Appalachian Basin takeaway capacity has been added in recent years, the existing and expected capacity may not be sufficient to keep pace with the increased production caused by accelerated drilling in the area in the short term.

Due to the concentrated nature of our portfolio of natural gas properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

Natural gas, NGLs and oil price declines have resulted in impairment of certain of our non-core assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, including long lived intangible assets, which could materially and adversely affect our results of operations in future periods.

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We review the carrying values of our proved oil and gas properties and goodwill for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In addition, we evaluate goodwill for impairment at least annually. A significant amount of judgment is involved in performing these evaluations because the results are based on estimated future events and estimated future cash flows. The estimated future cash flows used to test our proved oil and gas properties for recoverability are based on proved and, if determined reasonable by management, risk-adjusted probable reserves, utilizing assumptions generally consistent with the assumptions utilized by our management for internal planning and budgeting purposes. Key assumptions used in our analyses, include, among other things, the intended use of the asset, the anticipated production from reserves, future market prices for natural gas, NGLs and oil, future operating costs, inflation and the anticipated proceeds which may be received upon divestiture if there is a possibility that the asset will be divested prior to the end of its useful life. Commodity pricing is estimated by using a combination of the five-year NYMEX forward strip prices and assumptions related to gas quality, locational basis adjustments and inflation. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rate assumptions that marketplace participants would use in their estimates of fair value. When testing goodwill for impairment, we also consider the market value of our common stock and other valuation techniques when determining the fair value of our single reporting unit.

Future declines in natural gas, NGLs or oil prices, increases in operating costs or adverse changes in well performance, among other things, may result in our having to make significant future downward adjustments to our estimated proved reserves and/or could result in additional non-cash impairment charges to write-down the carrying amount of our assets, including other long lived intangible assets, which may have a material adverse effect on our results of operations in future periods.

Any impairment of our assets, including other long lived intangible assets, would require us to take an immediate charge to earnings. Such charges could be material to our results of operations and could adversely affect our results of operations and financial position. See “Impairment of Oil and Gas Properties and Goodwill” under Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

The unavailability or high cost of additional drilling rigs, completion services, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages or higher costs. Historically, there have been shortages of personnel and equipment as demand for personnel and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could materially adversely affect our business, results of operations, cash flows and financial position.

Our ability to drill for and produce natural gas and oil is dependent on the availability of adequate supplies of water for drilling and completion operations and access to water and waste disposal or recycling services at a reasonable cost and in accordance with applicable environmental rules. Restrictions on our ability to obtain water or dispose of produced water and other waste may adversely affect our results of operations, cash flows and financial position.

The hydraulic fracture stimulation process on which we depend to drill and complete natural gas and oil wells requires the use and disposal of significant quantities of water. Our ability to access sources of water and the availability of disposal alternatives to receive all of the water produced from our wells and used in hydraulic fracturing may affect our drilling and completion operations. Our inability to secure sufficient amounts of water, or to dispose of or recycle the water used in our operations, or to timely obtain water sourcing permits or other rights, could adversely affect our

operations. Additionally, the imposition of new environmental initiatives and regulations could include restrictions on our ability to obtain water or dispose of waste, which would adversely affect our business and results of operations, which could result in decreased cash flows.
In addition, federal and state regulatory agencies recently have focused on a possible connection between the operation of injection wells used for natural gas and oil waste disposal and increased seismic activity in certain areas. In some cases, operators of injection wells in the vicinity of seismic events have been ordered to reduce injection volumes or suspend operations. Increased regulation and attention given to induced seismicity in the states where we operate could lead to restrictions on our disposal well injection volumes and increased scrutiny of and delay in obtaining new disposal well permits, which could result in increased operating costs, which could be material, or a curtailment of our operations.

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The loss of key personnel could adversely affect our ability to execute our strategic, operational and financial plans.
Our operations are dependent upon key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, the success of our operations will depend, in part, on our ability to identify, attract, develop and retain experienced personnel. There is competition within our industry for experienced technical personnel and certain other professionals, which could increase the costs associated with identifying, attracting and retaining such personnel. If we cannot identify, attract, develop and retain our technical and professional personnel or attract additional experienced technical and professional personnel, our ability to compete in our industry could be harmed.
Competition in our industry is intense, and many of our competitors have substantially greater financial resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable oil and gas properties, as well as for the capital, equipment and labor required to operate and develop these properties. Many of our competitors have financial resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on existing and changing processes and may also have a greater ability to continue drilling activities during periods of low natural gas and oil prices and to absorb the burden of current and future governmental regulations and taxation.

We depend upon Equitrans Midstream, a third-party midstream provider, for a significant portion of our midstream services, and our failure to obtain and maintain access to the necessary infrastructure to successfully deliver natural gas, NGLs and oil to market may adversely affect our earnings, cash flows and results of operations.
Our delivery of natural gas, NGLs and oil depends upon the availability, proximity and capacity of pipelines, other transportation facilities and gathering and processing facilities primarily owned by third-parties, and our ability to contract with these third-parties. The capacity of transmission, gathering and processing facilities may be insufficient to accommodate potential production from existing and new wells, which may result in substantial discounts in the prices we receive for our natural gas, NGLs and oil or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Competition for access to pipeline infrastructure within the Appalachian Basin is intense, and our ability to secure access to pipeline infrastructure on favorable economic terms could affect our competitive position.

Historically our ownership interest in and control of EQM Midstream Partners, LP (EQM) and Rice Midstream Partners LP (RMP) allowed us to exercise greater control over the development of midstream infrastructure to service our operations. However, as a result of the Separation, we no longer control those operations and facilities and will be dependent on Equitrans Midstream and other third-party providers of these services. Access to midstream assets may be unavailable due to market conditions or mechanical or other reasons. In addition, at current commodity prices, construction of new pipelines and building of such infrastructure may occur more slowly. A lack of access to needed infrastructure, or an extended interruption of access to or service from our or third-party pipelines and facilities for any reason, including vandalism, sabotage or cyber-attacks on such pipelines and facilities or service interruptions due to gas quality, could result in adverse consequences to us, such as delays in producing and selling our natural gas, NGLs and oil. In addition, some of our third-party contracts involve significant long-term financial commitments on our part and could reduce our cash flow during periods of low prices for natural gas, NGLs and oil. Our usage of third parties for transmission, gathering and processing services subjects us to the performance risk of such third parties and may make us dependent upon those third parties to get our produced natural gas, NGLs and oil to market. To the extent these services are delayed or unavailable, we would be unable to realize revenue from wells served by such facilities until suitable arrangements are made to market our production. Our failure to obtain these services on acceptable terms could materially harm our business.

Finally, in order to ensure access to certain midstream facilities, we have entered into agreements that obligate us to pay demand charges to various pipeline operators. We also have commitments with third parties for processing capacity. We may be obligated to make payments under these agreements even if we do not fully utilize the capacity we have reserved, and these payments may be significant.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

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Negative public perception regarding us and/or our industry resulting from, among other things, the explosion of natural gas transmission and gathering lines, oil spills, and concerns raised by advocacy groups or the media about hydraulic fracturing, greenhouse gas or methane emissions or fossil fuels in general, or about royalty payment and surface use issues, may lead to increased litigation and regulatory, legislative and judicial scrutiny, which may, in turn, lead to new local, state and federal laws, regulations, guidelines and enforcement interpretations in safety, environmental, royalty and surface use areas. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, challenged or burdened by requirements that restrict our ability to profitably conduct our business.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are regulated extensively at the federal, state and local levels. Laws, regulations and other legal requirements have increased the cost to plan, design, drill, install, operate and abandon wells and related infrastructure. Our exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of water and other fluids and materials, including solid and hazardous wastes, incidental to natural gas and oil operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances.

Our operations are also subject to conservation and correlative rights regulations, including the regulation of the size of drilling and spacing units or field rule units; setbacks; the number of wells that may be drilled in a unit or in close proximity to other wells; drilling in the vicinity of coal mining operations and certain other structures; and the unitization or pooling of properties. Some states allow the statutory pooling and unitization of tracts to facilitate development and exploration, as well as joint development of existing contiguous leases. In addition, state conservation and natural gas and oil laws generally limit the venting or flaring of natural gas, and may set production allowances on the amount of annual production permitted from a well.

Environmental, health and safety legal requirements govern discharges of substances into the air, ground and water; the management and disposal of hazardous substances and wastes; the clean-up of contaminated sites; groundwater quality and availability; plant and wildlife protection; locations available for drilling; environmental impact studies and assessments prior to permitting; restoration of drilling properties after drilling is completed; and work practices related to employee health and safety.

To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Maintaining compliance with the laws, regulations and other legal requirements applicable to our business and any delays in obtaining related authorizations may affect the costs and timing of developing our natural gas, NGLs and oil resources. These requirements could also subject us to claims for personal injuries, property damage and other damages. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could materially adversely affect our results of operations, cash flows and financial position. Our failure to comply with the laws, regulations and other legal requirements applicable to our business, even if as a result of factors beyond our control, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and damages as well as corrective action costs.

In December 2018, changes to certain federal income tax laws were signed into law which impact us, including but not limited to: changes to the regular income tax rate; the elimination of the alternative minimum tax; full expensing of capital equipment; limited deductibility of interest expense; and increased limitations on deductible executive compensation. The current administration continues to debate further changes to federal income tax laws that could be enacted which could have a material impact on us. The most significant potential tax law changes include further changes to the regular income tax rate, the expensing of intangible drilling costs or percentage depletion, and further limited deductibility of interest expense, any of which could adversely impact our current and deferred federal and state income tax liabilities. State and local taxing authorities in jurisdictions in which we operate or own assets may enact new taxes, such as the imposition of a severance tax on the extraction of natural resources in states in which we produce natural gas, NGLs and oil, or change the rates of existing taxes, which could adversely impact our earnings, cash flows and financial position.

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In 2010, Congress adopted the Dodd-Frank Act, which established federal oversight and regulation of the over-the-counter derivative market and entities, such as us, that participate in that market. The Dodd-Frank Act required the CFTC, the SEC and other regulatory agencies to promulgate rules and regulations implementing the legislation. As of the filing date of this Annual Report on Form 10-K, the CFTC had adopted and implemented many final rules that impose regulatory obligations on all market participants, including us, such as recordkeeping and certain reporting obligations. Other rules that may be relevant to us or our counterparties have yet to be finalized. Because significant rules relevant to natural gas hedging activities have not been adopted or implemented, it is not possible at this time to predict the extent of the impact of the regulations on our hedging program, including available counterparties, or regulatory compliance obligations. We have experienced increased, and anticipate additional, compliance costs and changes to current market practices as participants continue to adapt to a changing regulatory environment.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing and governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of natural gas and oil wells, which could adversely affect our production.

We utilize hydraulic fracturing in the completion of our natural gas and oil wells. Hydraulic fracturing typically is regulated by state natural gas and oil commissions, but the EPA has asserted federal regulatory authority. For example, the EPA also finalized rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

Certain governmental reviews have been conducted or are underway that focus on the environmental aspects of hydraulic fracturing practices. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from constructing wells. See "Business-Regulation-Environmental, Health and Safety Regulation” for more information.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment and occupational health and workplace safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and occupational health and workplace safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters.

In addition, new or additional laws and regulations, new interpretations of existing requirements or changes in enforcement policies could impose unforeseen liabilities, significantly increase compliance costs or result in delays of, or denial of rights to conduct, our development programs. For example, in September 2015, the EPA and the Corps issued a final rule under the CWA defining the scope of the EPA's and the Corps' jurisdiction over WOTUS, but several legal challenges to the rule followed, and the WOTUS rule was stayed nationwide in October 2015 pending resolution of the court challenges. The EPA and the Corps proposed a rule in June 2017 to repeal the WOTUS rule, and announced their intent to issue a new rule defining the CWA's jurisdiction. In January 2018, the U.S. Supreme Court issued a decision finding that jurisdiction to hear challenges to the WOTUS rule resides with the federal district courts; consequently, the previously filed district court cases were allowed to proceed, resulting in a patchwork of implementation in some states and stays in others. Following the U.S. Supreme Court's decision, the EPA and the Corps issued a final rule in January 2018 staying implementation of the WOTUS rule for two years while the agencies reconsider the rule, but a federal judge barred the agencies' suspension of the rule in August 2018. Subsequently, various district court decisions

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revived the WOTUS rule in 22 states, the District of Columbia, and the U.S. territories and enjoined implementation of the rule in 28 states. In December 2018, the EPA and the Corps released a proposal to redefine the definition of WOTUS. The new proposed definition narrows the scope of waters that are covered as jurisdictional under the WOTUS rule. The proposed definition may be subject to an expanded comment period and future litigation. As a result, future implementation of the WOTUS rule is uncertain at this time. To the extent the WOTUS rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Such potential regulations or litigation could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which in turn could materially adversely affect our results of operations and financial position. Further, the discharges of natural gas, NGLs, oil, and other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties.

Regulations related to the protection of wildlife could adversely affect our ability to conduct drilling activities in some of the areas where we operate.
Our operations can be adversely affected by regulations designed to protect various wildlife. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in constraints on our exploration and production activities. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Conservation measures and technological advances could reduce demand for natural gas and oil.
Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to natural gas and oil, technological advances in fuel economy and energy generation devices could reduce demand for natural gas and oil. The impact of the changing demand for natural gas and oil could adversely impact our earnings, cash flows and financial position.
Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the natural gas, NGLs and oil that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.
In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore natural gas and oil production sources in the United States on an annual basis, which include certain of our operations. At the state level, several states including Pennsylvania have proceeded with regulation targeting GHG emissions. Such state regulations could impose increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of federal legislation in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. While Pennsylvania is not currently a member of the RGGI, a multi-state regional cap and trade program comprised of several Eastern U.S.

states, it is possible that it may join RGGI in the future. This could result in increased operating costs if our operations are required to purchase emission allowances.

On an international level, the United States is one of almost 200 nations that, in December 2015, agreed to the Paris Agreement which calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. The Paris Agreement was signed by the United States in April 2016 and entered into force on November 4, 2016; however, the Paris Agreement does not impose any binding obligations on its participants. In August 2017, the U.S. Department of State officially informed the United Nations of the United States' intent 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 reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could also adversely affect demand for the natural gas, NGLs and oil we produce and lower the value of our reserves.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of finding for the energy sector. Moreover, activist shareholders have introduced proposals that may seek to force companies to adopt aggressive emission reduction targets or to shift away from more carbon-intensive activities. While we cannot predict the outcomes of such proposals, they could ultimately make it more difficult to engage in exploration and production activities.

Finally, it should be noted that a number of 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 have the potential to cause physical damage to our assets or affect the availability of water and thus could have an adverse effect on our exploration and production operations. See "Business-Regulation-Environmental, Health and Safety Regulation" for more information.
The growth of our business through strategic transactions may expose us to various risks.

We periodically engage in acquisitions, dispositions and other strategic transactions, including joint ventures. These transactions involve various inherent risks, such as our ability to obtain the necessary regulatory and third party approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; the assumption of potential environmental or other liabilities; and our ability to realize the benefits expected from the transactions. In addition, various factors, including prevailing market conditions, could negatively impact the benefits we receive from transactions. Competition for transaction opportunities in our industry is intense and may increase the cost of, or cause us to refrain from, completing transactions. Joint venture arrangements may restrict our operational and corporate flexibility. Moreover, joint venture arrangements involve various risks and uncertainties, such as committing us to fund operating and/or capital expenditures, the timing and amount of which we may have little or partial control over, and our joint venture partners may not satisfy their obligations to the joint venture. Our inability to complete a transaction or to achieve our strategic or financial goals in any transaction could have significant adverse effects on our earnings, cash flows and financial position.

Acquisitions may disrupt our current plans or operations and may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities. We may not achieve the intended benefits of our acquisition of Rice Energy Inc.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include estimates of recoverable reserves, exploration potential, future natural gas, NGLs and oil prices, operating costs, production taxes and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well or lease that we acquire, and even when we inspect a well or lease we may not discover structural, subsurface, or environmental problems that may exist or arise.

There may be threatened or contemplated claims against the assets or businesses we acquire related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We often assume certain liabilities, and we may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. At times, we acquire interests in properties on an "as is" basis with limited representations and warranties and limited remedies for breaches of such representations and warranties. In addition, significant acquisitions can change the nature of our operations and business if the acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties.

On November 13, 2017, we completed the acquisition of Rice Energy Inc. (Rice). There can be no assurance that we will be able to successfully integrate Rice's assets or otherwise realize the expected benefits of the acquisition of Rice. In addition, our business may be negatively impacted if we are unable to effectively manage our expanded operations going forward. The integration has required and will continue to require significant time and focus from management and could disrupt current plans and operations, which could delay the achievement of our strategic objectives.

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Changes in our business following the completion of recent significant transactions, including the acquisition of Rice and the Separation and Distribution, may result in disruptions to our business and negatively impact our operations and our relationships with our customers and business partners.

Over the last two years we have completed multiple significant transactions, including the acquisition of Rice and the Separation and Distribution, with material work to be completed to achieve synergies and rationalize operations. As a result of these transactions, our company and employees have experienced significant changes, including the departure of members of senior management, new leadership in significant roles, and employee re-assignments necessary in connection with the Separation as well as a reduction in our workforce. The combination of these factors may materially adversely affect our operations. Further, uncertainty related to our business following the Separation may lead customers and other parties to terminate or attempt to negotiate changes in existing business relationships, or consider entering into business relationships with parties other than us. These disruptions could materially adversely affect our results of operations, financial position and prospects.

The Separation and Distribution may subject us to future liabilities.

In November 2018, we completed the Separation and Distribution, resulting in the spin-off of Equitrans Midstream, a stand-alone publicly traded corporation which holds our former midstream business.

Pursuant to agreements we entered into with Equitrans Midstream in connection with the Separation, we and Equitrans Midstream are each generally responsible for the obligations and liabilities related to our respective businesses. Pursuant to those agreements, we and Equitrans Midstream each agreed to cross-indemnities principally designed to allocate financial responsibility for the obligations and liabilities of our business to us and those of Equitrans Midstream's business to it. However, third parties, including governmental agencies, could seek to hold us responsible for obligations and liabilities that Equitrans Midstream agreed to retain or assume, and there can be no assurance that the indemnification from Equitrans Midstream will be sufficient to protect us against the full amount of such obligations and liabilities, or that Equitrans Midstream will be able to fully satisfy its indemnification obligations. Additionally, if a court were to determine that the Separation or related transactions were consummated with the actual intent to hinder, delay or defraud current or future creditors or resulted in Equitrans Midstream receiving less than reasonably equivalent value when it was insolvent, or that it was rendered insolvent, inadequately capitalized or unable to pay its debts as they become due, then it is possible that the court could disregard the allocation of obligations and liabilities agreed to between us and Equitrans Midstream, impose substantial obligations and liabilities on us and void some or all of the Separation-related transactions. Any of the foregoing could adversely affect our results of operations and financial position.

If there is a later determination that the Distribution or certain related transactions are taxable for U.S. federal income tax purposes because the facts, assumptions, representations or undertakings underlying the IRS private letter ruling and/or opinion of counsel are incorrect or for any other reason, we could incur significant liabilities.

In connection with the Separation and Distribution, we obtained a private letter ruling from the IRS and an opinion of outside counsel regarding the qualification of the Distribution, together with certain related transactions, as a transaction that is generally tax-free, for U.S. federal income tax purposes, under Sections 355 and 368(a)(1)(D) of the U.S. Internal Revenue Code (the Code) and certain other U.S. federal income tax matters relating to the Distribution and certain related transactions. The IRS private letter ruling and the opinion of counsel are based upon and rely on, among other things, various facts and assumptions, as well as certain representations, statements and undertakings of us and Equitrans Midstream, including those relating to the past and future conduct of us and Equitrans Midstream. If any of these representations, statements or undertakings is, or becomes, inaccurate or incomplete, or if we or Equitrans Midstream breach any representations or covenants contained in any of the Separation-related agreements and documents or in any documents relating to the IRS private letter ruling and/or the opinion of counsel, we and our shareholders may not be able to rely on the IRS private letter ruling or the opinion of counsel.

Notwithstanding receipt of the IRS private letter ruling and the opinion of counsel, the IRS could determine on audit that the Distribution and/or certain related transactions should be treated as taxable transactions for U.S. federal income tax purposes if it determines that any of the representations, assumptions or undertakings upon which the IRS private letter ruling was based are false or have been violated or if it disagrees with the conclusions in the opinion of counsel that are not covered by the ruling or for other reasons, including as as result of certain significant changes in the stock ownership of the Company or Equitrans Midstream after the Distribution further described below. An opinion of counsel represents the judgment of such counsel and is not binding on the IRS or any court, and the IRS or a court may disagree with the conclusions in such opinion of counsel. Accordingly, notwithstanding receipt of the IRS private letter ruling and the opinion of counsel, there can be no assurance that the IRS will not assert that the Distribution and/or certain related transactions should be treated as taxable transactions or that a court would not sustain such a challenge. In the event the IRS were to prevail with such challenge, we, Equitrans Midstream and our shareholders could be subject to material U.S. federal and state income tax liabilities. In connection with the Separation, we

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and Equitrans Midstream entered into a tax matters agreement, which described the sharing of any such liabilities between us and Equitrans Midstream.

Even if the Distribution otherwise qualifies as generally tax-free under Section 355 and Section 368(a)(1)(D) of the Code, the Company (but not shareholders) would be subject to material U.S. federal and state income tax liability under Section 355(e) of the Code if one or more persons acquire, directly or indirectly, a 50-percent or greater interest (measured by either vote or value) in our stock or in the stock of Equitrans Midstream (excluding, for this purpose, the acquisition of stock of Equitrans Midstream by holders of our stock in the Distribution) as part of a plan or series of related transactions that includes the Distribution. Any acquisition of our stock or stock of Equitrans Midstream (or any predecessor or successor corporation) within two years before or after the Distribution generally would be presumed to be part of a plan that includes the Distribution, although the parties may be able to rebut that presumption under certain circumstances. Additionally, Equitrans Midstream is subject to certain agreements entered into with us that restrict, within two years of the Distribution, the ability of Equitrans Midstream to engage in certain corporate transactions without obtaining an advance ruling from the IRS and our prior consent. The process for determining whether an acquisition is part of a plan under these rules is complex, inherently factual in nature and subject to a comprehensive analysis of the facts and circumstances of the particular case. Notwithstanding the IRS private letter ruling or any opinion of counsel described above, we or Equitrans Midstream may cause or permit a change in ownership of our stock or stock of Equitrans Midstream sufficient to result in a material tax liability to us.

The Separation may not achieve some or all of the anticipated benefits.

We may not realize some or all of the anticipated strategic, financial, operational or other benefits from the Separation. As independent publicly-traded companies, we and Equitrans Midstream are smaller, less diversified companies with a narrower business focus and may be more vulnerable to changing market conditions, which could materially adversely affect our and its results of operations, cash flows and financial position. Further, we may be required to expend additional resources to consolidate and/or upgrade our information technology processes and systems to achieve our strategic goals.

We are a significant shareholder of Equitrans Midstream and the value of our investment in Equitrans Midstream may fluctuate substantially.

We own approximately 19.9% of the outstanding shares of common stock of Equitrans Midstream. The value of our investment in Equitrans Midstream may be adversely affected by negative changes in its results of operations, cash flows and financial position, which may occur as a result of the many risks attendant with operating in the midstream industry, including loss of gathering and transportation volumes, the effect of laws and regulations on the operation of its business and development of its assets, increased competition, loss of contracted volumes, adverse rate-making decisions, policies and rulings by the FERC, delays in the timing of or the failure to complete expansion projects, lack of access to capital and operating risks and hazards.

We intend to dispose of our interest in Equitrans Midstream through one or more exchanges of our shares of Equitrans Midstream common stock for our debt or one or more sales of such shares for cash. However, we can offer no assurance that we will be able to complete such disposition or as to the value we will realize. The occurrence of any of these and other risks faced by Equitrans Midstream could adversely affect the value of our investment in Equitrans Midstream.

Future sales of our common stock in the public market could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

See Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” for further discussion regarding the Company’s exposure to market risks, including the risks associated with the Company's use of derivative contracts to hedge commodity prices.

Item 1B. Unresolved Staff Comments

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None.

Item 2. Properties

Principal facilities are owned or, in the case of certain office locations, warehouse buildings and equipment, leased, by the Company and its subsidiaries. The majority of the Company's properties are located on or under (i) private properties owned in fee, held by lease or occupied under perpetual easements or other rights acquired for the most part without warranty of underlying land titles or (ii) public highways under franchises or permits from various governmental authorities. The Company's facilities are generally well maintained and, where appropriate, are replaced or expanded to meet operating requirements.

The Company's properties are located primarily in Pennsylvania, West Virginia and Ohio. The Company has approximately 1.4 million gross acres (approximately 74% of which are considered undeveloped), which encompass substantially all of the Company's acreage of proved developed and undeveloped natural gas and oil producing properties. Of these gross acres, approximately 1.1 million are in the Marcellus play, much of which has associated deep Utica or Upper Devonian drilling rights, and approximately 0.1 million are in the Ohio Utica play. Although most of the Company's wells are drilled to relatively shallow depths (5,000 to 8,500 feet below the surface), the Company retains what are normally considered "deep rights" on the majority of its acreage. As of December 31, 2018, the Company estimated its total proved reserves to be 21.8 Tcfe, consisting of proved developed producing reserves of 11.3 Tcfe, proved developed non-producing reserves of 0.2 Tcfe and proved undeveloped reserves of 10.3 Tcfe. Substantially all of the Company's reserves reside in continuous accumulations.

The Company's estimate of proved natural gas, NGLs and oil reserves is prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor's degree
in Chemical Engineering from the Pennsylvania State University and has 21 years of experience in the oil and gas industry. To ensure that the reserves are materially accurate, management reviews the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves. Additionally, division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems, and the reserve reconciliation between prior year reserves and current year reserves is reviewed by senior management.

The Company's estimate of proved natural gas, NGLs and oil reserves is audited by the independent consulting firm of Ryder Scott Company, L.P. (Ryder Scott), which is hired by the Company's management. Since 1937, Ryder Scott has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally. In the course of its audit, Ryder Scott reviewed 100% of the total net natural gas, NGLs and oil proved reserves attributable to the Company's interests as of December 31, 2018. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 81% of the Company's proved developed reserves. Ryder Scott's audit of the remaining approximately 19% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 115 wells per case for non-operated wells. For undeveloped locations, the Company determined, and Ryder Scott reviewed and approved, the areas within the Company's acreage considered to be proven. Reserves were assigned and projected by the Company's reserves engineers for locations within these proven areas and approved by Ryder Scott based on analogous type curves and offset production information. Ryder Scott's audit report has been filed herewith as Exhibit 99.

No report has been filed with any federal authority or agency reflecting a 5% or more difference from the Company's estimated total reserves. Additional information relating to the Company's estimates of natural gas, NGLs and crude oil reserves and future net cash flows is provided in Note 18 (unaudited) to the Consolidated Financial Statements.

In 2018, the Company commenced drilling operations (spud or drilled) on 117 gross horizontal Marcellus wells, 5 gross horizontal Upper Devonian wells and 31 gross horizontal Ohio Utica wells. Sales volumes in 2018 from the Marcellus play, including the Upper Devonian play, was 1,230 Bcfe. Over the past five years, the Company has experienced a 97% developmental drilling success rate.

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Natural gas, NGLs and crude oil pricing:

	For the Years Ended December 31,		
	2018	2017	2016
Natural Gas:			
Average sales price (excluding cash settled derivatives) ($/Mcf)	$ 3.04	$ 2.82	$ 1.88
Average sales price (including cash settled derivatives) ($/Mcf)	$ 2.89	$ 2.89	$ 2.41
NGLs (excluding ethane):			
Average sales price (excluding cash settled derivatives) ($/Bbl)	$ 37.63	$ 31.59	$ 19.43
Average sales price (including cash settled derivatives) ($/Bbl)	$ 36.56	$ 30.90	$ 19.43
Ethane:			
Average sales price ($/Bbl)	$ 8.09	$ 6.32	$ 5.08
Crude Oil:			
Average sales price ($/Bbl)	$ 52.70	$ 40.70	$ 34.73

For additional information on pricing, see “Average Realized Price Reconciliation” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

The Company’s average per unit production cost, excluding production taxes, of natural gas, NGLs and oil during 2018, 2017 and 2016 was $0.07 per Mcfe, $0.13 per Mcfe and $0.15 per Mcfe, respectively.

Summary of productive and in process natural gas and oil wells at December 31, 2018:

	Natural Gas	Oil
Total productive wells at December 31, 2018:		
Total gross productive wells	3,258	—
Total net productive wells	3,050	—
Total in-process wells at December 31, 2018:	0	
Total gross in-process wells	310	—
Total net in-process wells	278	—

Summary of proved natural gas, oil and NGLs reserves as of December 31, 2018 based on average fiscal year prices:

	Natural Gas (MMcf)	Oil and NGLs (Bbls)
Developed	10,887,953	110,368
Undeveloped	9,917,499	58,186
Total proved reserves	20,805,452	168,554

Total acreage at December 31, 2018:	
Total gross productive acres	367,378
Total net productive acres	354,817
Total gross undeveloped acres	1,021,615
Total net undeveloped acres	866,395

As of December 31, 2018, the Company had no proved undeveloped reserves that had remained undeveloped for more than five years.

The Company has an active lease renewal program in areas targeted for development. In the event that production is not established or the Company takes no action to extend or renew the terms of its leases, the Company's net undeveloped acreage that will expire over the next three years as of December 31, 2018 is 90,543, 79,107 and 54,373 for the years ended December 31, 2019, 2020 and 2021, respectively.

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Number of net productive and dry exploratory and development wells drilled:

	For the Years Ended December 31,		
	2018	2017	2016
Exploratory wells:			
Productive	—	—	—
Dry	—	1.0	—
Development wells:			
Productive	210.2	149.2	140.9
Dry	4.6	4.9	15.0

The dry developmental wells in 2018 and 2017 are primarily related to non-core wells no longer planned to be drilled to depth or completed and acquired wells with mechanical integrity issues. The number of dry developmental wells drilled in 2016 were primarily related to vertical wells that are no longer planned to be drilled horizontally due to the uncertainty of identifying a near-term pipeline solution.

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The table below provides select production, sales and acreage data by state (as of December 31, 2018 unless otherwise noted), which is substantially all from the Appalachian Basin. NGLs and oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods. Refer to the "Average Realized Price Reconciliation" table in Item 7 of this Annual Report on Form 10-K for sales volumes by final product.

	Pennsylvania	West Virginia (d)	Ohio	Other (b)	Total
Natural gas, oil and NGLs production (MMcfe) – 2018 (a) (c)	918,156	330,504	208,197	37,806	1,494,663
Natural gas, oil and NGLs production (MMcfe) – 2017 (a) (c)	456,614	352,481	24,426	74,371	907,892
Natural gas, oil and NGLs production (MMcfe) – 2016 (a)	426,524	272,529	541	76,769	776,363
Natural gas, oil and NGLs sales (MMcfe) – 2018 (c)	922,033	323,976	209,428	32,252	1,487,689
Natural gas, oil and NGLs sales (MMcfe) – 2017 (c)	456,600	343,199	24,113	63,608	887,520
Natural gas, oil and NGLs sales (MMcfe) – 2016	429,011	264,452	536	64,968	758,967
Average net revenue interest of proved reserves (%)	78.9 %	82.8 %	47.7 %	— %	75.9 %
Total gross productive wells	1,778	1,259	221	—	3,258
Total net productive wells	1,733	1,215	102	—	3,050
Total gross productive acreage	223,977	103,617	39,784	—	367,378
Total gross undeveloped acreage	444,439	486,301	48,243	42,632	1,021,615
Total gross acreage	668,416	589,918	88,027	42,632	1,388,993
Total net productive acreage	221,954	102,836	30,027	—	354,817
Total net undeveloped acreage	419,612	392,698	34,368	19,717	866,395
Total net acreage	641,566	495,534	64,395	19,717	1,221,212
(Amounts in Bcfe)					
Proved developed producing reserves	7,525	2,924	827	—	11,276
Proved developed non-producing reserves	203	—	71	—	274
Proved undeveloped reserves	8,497	1,059	711	—	10,267
Proved developed and undeveloped reserves	16,225	3,983	1,609	—	21,817
Gross proved undeveloped drilling locations	547	75	72	—	694
Net proved undeveloped drilling locations	498	71	46	—	615

(a) All production information related to natural gas is reported net of the effect of any reduction in natural gas volumes resulting from the processing of NGLs.

(b) Other primarily includes Kentucky and Virginia. During 2018, as a result of the Huron Divestiture, the Company sold approximately 2.5 million non-core, net acres in the Huron play, however, the Company retained the deep drilling rights across the divested acreage in Kentucky and Virginia of 1.5 million and 0.2 million, respectively, which are excluded from the acreage totals above. Natural gas, oil and NGLs production and sales primarily represents activity prior to the completion of the 2018 Divestitures.

(c)

For the years ended December 31, 2018 and 2017, the natural gas, oil and NGLs production volumes and sales volumes includes volumes from the production operations acquired in the Rice Merger (defined in Note 3 to the Consolidated Financial Statements) which occurred on November 13, 2017.

(d) During 2018, as a result of the Huron Divestiture, the Company sold approximately 2.5 million non-core, net acres in the Huron play, however, the Company retained the deep drilling rights across the divested acreage in West Virginia of 0.8 million, which is excluded from the acreage totals above.

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The Company sells natural gas and NGLs within the Appalachian Basin and in markets accessible through its transportation portfolio under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. The Company expects to fulfill these delivery commitments with existing proved developed and proved undeveloped reserves. As of December 31, 2018, the Company's delivery commitments for the next five years were as follows:

For the Year Ended December 31,	Natural Gas (Bcf)	Natural Gas Liquids (Mbbls)
2019	1,298	3,817
2020	902	1,841
2021	769	1,836
2022	577	1,833
2023	504	1,825

During the year ended December 31, 2018, the Company's total proved developed reserves increased by 252 Bcfe. The increase in proved developed reserves was primarily due to the conversion of approximately 2,722 Bcfe of proved undeveloped reserves to proved developed reserves, an upward revision of 459 Bcfe from processing, ownership changes, and other revisions and the addition of 315 Bcfe due to extensions, discoveries, and other additions that were not previously recorded as proved reserves. These increases were partly offset by the sale of hydrocarbons in place of 1,749 Bcfe associated with the 2018 Divestitures as described in Note 8 and 2018 production of 1,495 Bcfe.

The Company's 2018 extensions, discoveries and other additions totaled 4,739 Bcfe, which exceeded the 2018 production of 1,495 Bcfe. Of these, 315 Bcfe of proved developed reserves were extensions from reservoirs underlying acreage not previously booked as proved, 886 Bcfe of proved undeveloped reserves were extensions from acreage proved by drilling activity, and 3,538 Bcfe of other proved undeveloped additions are associated with acreage that was excluded from prior year proved reserves bookings, but subsequently became proved due to inclusion with the Company's five year drilling plan.

The Company's 2018 revisions totaled a downward adjustment of 1,125 Bcfe which was primarily due to the removal of certain proved undeveloped locations that are no longer expected to be developed within 5 years of initial booking as proved reserves, resulting from changes in Company's future development plans to focus more heavily on developing the Company's core Pennsylvania assets.

Wells located in Pennsylvania and West Virginia are primarily in Marcellus formations with depths ranging from 5,000 feet to 8,500 feet. Wells located in Ohio are primarily in Utica formations with depths ranging from 8,500 feet to 10,500 feet.

The Company's corporate headquarters is located in leased office space in Pittsburgh, Pennsylvania. The Company also owns or leases office space in Pennsylvania, West Virginia and Ohio.

See "Capital Resources and Liquidity" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," for a discussion of capital expenditures.

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Item 3. Legal Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal and other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial condition, results of operations or liquidity of the Company.

Environmental Proceedings

Phoenix S Impoundment, Tioga County, Pennsylvania

In June and August 2012, the Company received three Notices of Violation (NOVs) from the PADEP. The NOVs alleged violations of the Pennsylvania Oil and Gas Act and Clean Streams Law in connection with the unintentional release in May 2012, by a Company vendor, of water from an impaired water pit at a Company well location in Tioga County, Pennsylvania. Since confirming a release, the Company has cooperated with the PADEP in remediating the affected areas.

During the second quarter of 2014, the Company received a proposed consent assessment of civil penalty from the PADEP that proposed a civil penalty related to the NOVs. On September 19, 2014, the Company filed a declaratory judgment action in the Commonwealth Court of Pennsylvania against the PADEP seeking a court ruling on the PADEP’s legal interpretation of the penalty provisions of the Clean Streams Law, which interpretation the Company believed was legally flawed and unsupportable. On October 7, 2014, based on its interpretation of the penalty provisions, the PADEP filed a complaint against the Company before the Pennsylvania Environmental Hearing Board (the EHB) seeking $4.53 million in civil penalties. In January 2017, the Commonwealth Court ruled in favor of the Company, finding the PADEP’s interpretation of the penalty provisions of the Clean Streams Law erroneous. The PADEP appealed that decision to the Pennsylvania Supreme Court, and the parties made oral arguments in front of the Pennsylvania Supreme Court on November 28, 2017. Following a July 2016 hearing before the EHB, in May 2017, the EHB ruled that the Company should pay $1.1 million in civil penalties. In June 2017, both the Company and the PADEP appealed the EHB’s decision to the Commonwealth Court. In September 2018, the Commonwealth Court upheld the $1.1 million civil penalty, which the Company paid in November 2018. The payment of the civil penalty did not have a material impact on the financial condition, results of operations or liquidity of the Company.

Fresh Water Pipeline Bore Release, Allegheny County, Pennsylvania

On February 24, 2017, the Company received an NOV from the PADEP. The NOV alleged violations of the Pennsylvania Oil and Gas Act and Clean Streams Law related to an unintentional release, by a Company vendor, of mine water into the Monongahela River in January 2017 from a mine void that was pierced while boring under a road for the installation of a fresh water pipeline in Allegheny County, Pennsylvania. The Company cooperated with the PADEP to take appropriate actions to stop the release. On February 15, 2017, the Company entered into a civil penalty settlement related to the release with the Pennsylvania Fish and Boat Commission for $4,555 for alleged violations of the Pennsylvania Fish and Boat Code. In November 2018, the Company and the PADEP entered into a settlement agreement related to the release. Under the terms of the agreement, the Company paid a civil penalty of $294,000 and provided $100,000 in trust for future maintenance of a mine water drain. The payments did not have a material impact on the financial condition, results of operations or liquidity of the Company.

Wilson Creek Water Withdrawals, Tioga County, Pennsylvania

On June 7, 2018, the Company received an NOV from the Susquehanna River Basin Commission (the SRBC). The NOV alleged violations of the Company's Water Management Plan and its Wilson Creek Docket related to the withdrawal of water from Wilson Creek between March 14, 2018 and April 3, 2018, when the stream flow was below the required flow protection threshold. The Company cooperated fully with the SRBC to address the matter. On December 18, 2018, the Company and the SRBC agreed to settle this matter and the Company paid a civil penalty of $120,000. The payment of the civil penalty did not have a material impact on the financial condition, results of operations or liquidity of the Company.

Erosion and Sedimentation Releases, Allegheny County, Pennsylvania

Between November 2017 and March 2018, the Company received multiple NOVs from the PADEP relating to four of the Company's well pads in Allegheny County, Pennsylvania. During this time period, Pennsylvania experienced unprecedented amounts of rainfall. The NOVs alleged violations of the Oil and Gas Act, and Clean Streams Law in connection with the effects

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of the rainfall on erosion and sedimentation controls at the Prentice, Fetchen, Oliver East, and Oliver West well pads. The Company cooperated fully with the PADEP to take appropriate actions to address the erosion and sedimentation control issues. The Company and the PADEP are currently negotiating a civil penalty settlement. While the Company expects the PADEP's claims to result in penalties that exceed $100,000, the Company expects that the resolution of this matter will not have a material impact on the financial condition, results of operations or liquidity of the Company.

Phoenix S Pad Well Control Incident, Tioga County, Pennsylvania

On December 1, 2017 and May 1, 2018, the Company received NOVs from the PADEP relating to a well control incident that occurred at a Phoenix S well on November 12, 2017. The well was brought back under control, but in the interim natural gas was vented to the atmosphere and flowback water was released to the ground water and a stream. The Company fully cooperated with the PADEP and took appropriate actions to address the environmental impacts from the incident. On January 22, 2019, the Company and the PADEP agreed to settle this matter and the Company agreed to pay a civil penalty of $138,000 to resolve the matter. The payment of the civil penalty did not have a material impact on the financial condition, results of operations or liquidity of the Company.

Other Legal Proceedings

Kay Company, LLC, et al. v. EQT Production Company, et al., United States District Court for the Northern District of West Virginia

On January 16, 2013, several royalty owners who had entered into leases with EQT Production Company, a subsidiary of the Company, filed a gas royalty class action lawsuit in the Circuit Court of Doddridge County, West Virginia. The suit alleged that EQT Production Company and a number of related companies, including the Company, EQT Energy, LLC, EQT Investments Holdings, LLC, EQM (the Company's former midstream affiliate) and Equitrans Gathering Holdings, LLC (formerly known as EQT Gathering Holdings, LLC, and a former subsidiary of the Company), failed to pay royalties on the fair value of the gas produced from the leases and took improper post-production deductions from the royalties paid. The plaintiffs sought more than $100 million (according to expert reports) in compensatory damages, punitive damages, and other relief. On May 31, 2013, the defendants removed the lawsuit to federal court. On September 6, 2017, the district court granted the plaintiffs' motion to certify the class and granted the plaintiffs' motion for summary judgment, finding that EQT Production Company and its marketing affiliate EQT Energy, LLC are alter egos of one another. The defendants sought immediate appeal of the class certification. On November 30, 2017, the Court of Appeals declined the request for an immediate review. On February 13, 2019, the Company announced that it and the other defendants reached a tentative settlement agreement with the class representatives. Pursuant to the terms of the proposed settlement agreement, the Company agreed to pay $53.5 million into a settlement fund that will be established to disburse payments to class participants, and stop taking future post production deductions on leases that are determined by the Court to not permit deductions. The Company and the class representatives also agreed that future royalty payments will be based on a clearly defined index pricing methodology. The tentative settlement agreement is subject to Court approval and achieving a threshold minimum percentage of participation by the class members. Each class member will have the opportunity to opt out of the settlement. If approved, the settlement will resolve the royalty claims for the class period, which spans from 2009 through 2017.

Item 4. Mine Safety Disclosures

Not Applicable.

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Executive Officers of the Registrant (as of February 14, 2019)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Erin R. Centofanti (43)	Executive Vice President, Production (2018)	Elected to present position October 2018. Ms. Centofanti served as Senior Vice President, Asset Development, EQT Production Company, from March 2017 to October 2018; Senior Vice President, Engineering, EQT Production Company, from November 2014 to March 2017; Vice President, Commercial Operations, EQT Energy, LLC, from February 2014 to November 2014; and Vice President, Business Development, EQT Production Company, from July 2011 to February 2014.
Donald M. Jenkins (46)	Executive Vice President, Commercial Business Development, Information Technology and Safety (2017)	Elected to present position November 2018. Mr. Jenkins served as the Company's Chief Commercial Officer from March 2017 to November 2018; Executive Vice President, Commercial, EQT Energy, LLC, from May 2014 to February 2017; and Senior Vice President, Trading and Origination, EQT Energy, LLC, from December 2012 to May 2014.
Jonathan M. Lushko (43)	General Counsel and Senior Vice President, Government Affairs (2018)	Elected to present position October 2018. Mr. Lushko served as the Company's Deputy General Counsel, Governance & Enterprise Risk, from May 2017 to October 2018. Mr. Lushko joined the Company in 2006 as Counsel, and later served as Senior Counsel prior to assuming the role of Deputy General Counsel, Governance & Enterprise Risk in May 2017.
Robert J. McNally (48)	President and Chief Executive Officer (2016)	Elected to present position November 2018. Mr. McNally served as Senior Vice President and Chief Financial Officer of the Company from March 2016 to November 2018, and in March 2017 he assumed additional management responsibilities for the Business Development, Facilities, Information Technology, Innovation, and Procurement functions. Mr. McNally served as a Director and Senior Vice President and Chief Financial Officer of the general partners of EQM Midstream Partners, LP and EQGP Holdings, LP (master limited partnerships formed by the Company and divested by the Company as part of the Separation, from March 2016 to October 2018. He also served as a Director and Senior Vice President and Chief Financial Officer of the general partner of Rice Midstream Partners LP (former master limited partnership acquired by the Company through its acquisition of Rice Energy Inc.) from November 2017 to July 2018. Prior to joining the Company, Mr. McNally served as Executive Vice President and Chief Financial Officer of Precision Drilling Corporation, a publicly traded drilling services company, from July 2010 to March 2016. Mr. McNally is also a Director of the Company, having served on the Company's Board of Directors since November 2018.
Jeffery C. Mitchell (46)	Vice President and Principal Accounting Officer (2018)	Elected to present position November 2018. Mr. Mitchell served as Vice President and Controller of the Company's production business from March 2015 to November 2018; Corporate Director, Internal Audit, from March 2013 to March 2015; and Corporate Director, Internal Audit and Financial Risk, from October 2011 to March 2013.
David J. Smith (60)	Senior Vice President, Human Resources (2018)	Elected to present position November 2018. Mr. Smith served as Corporate Director, Compensation and Benefits, of the Company from February 1995 to November 2018.

Jimmi Sue Smith (46)	Senior Vice President and Chief Financial Officer (2016)	Elected to present position November 2018. Ms. Smith served as the Company's Chief Accounting Officer from September 2016 to November 2018; Vice President and Controller of the Company's midstream and commercial businesses from March 2013 to September 2016; and Vice President and Controller of the Company's midstream business from January 2013 through March 2013. Ms. Smith also served as Chief Accounting Officer of the general partners of EQM Midstream Partners, LP and EQGP Holdings, LP from September 2016 to October 2018, and served as the Chief Accounting Officer of the general partner of Rice Midstream Partners LP, from November 2017 to July 2018.

All executive officers have executed agreements with the Company and serve at the pleasure of the Company's Board of Directors. Officers are elected annually to serve during the ensuing year or until their successors are elected and qualified, or until death, resignation or removal.

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PART II

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

The Company’s common stock is listed on the New York Stock Exchange trading under the ticker symbol "EQT."

As of January 31, 2019, there were 2,188 shareholders of record of the Company’s common stock.

The amount and timing of dividends declared and paid by the Company, if any, is subject to the discretion of the Company's Board of Directors and depends upon business conditions, such as the Company’s results of operations and financial condition, strategic direction and other factors. The Company's Board of Directors has the discretion to change the annual dividend rate at any time for any reason.

Recent Sales of Unregistered Securities

None.

Market Repurchases

The following table sets forth the Company’s repurchases of equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended, that occurred during the three months ended December 31, 2018:

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 value of shares that may yet be purchased under plans or programs
October 2018 (October 1 – October 31)	424	$ 46.78	—	$ —
November 2018 (November 1 – November 30)	25,332	31.35	—	—
December 2018 (December 1 – December 31)	242	17.20	—	—
Total	25,998	$ 31.47	—	—

(a) Reflects the number of shares withheld by the Company to pay taxes upon vesting of restricted stock plus the number of shares purchased as part of publicly announced plans or programs.

Stock Performance Graph

The following graph compares the most recent five-year cumulative total return attained by holders of the Company’s common stock with the cumulative total returns of the S&P 500 Index and two customized peer groups. The individual companies of the 2017 customized peer group (the 2017 Self-Constructed Peer Group) and the 2018 customized peer group (the 2018 Self-Constructed Peer Group) are listed in footnotes (a) and (b) below, respectively. An investment of $100 (with reinvestment of all dividends) is assumed to have been made at the close of business on December 31, 2013 in the Company’s common stock, in the S&P 500 Index and in each of the customized peer groups. Historical prices prior to the Separation and Distribution in November 2018 have been adjusted to reflect the value of the Separation and Distribution transactions. Relative performance is tracked through December 31, 2018.

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	12/13	12/14	12/15	12/16	12/17	12/18
EQT Corporation	$100.00	$84.42	$58.23	$73.18	$63.82	$39.05
S&P 500	100.00	113.69	115.26	129.05	157.22	150.33
2017 Self-Constructed Peer Group (a)	100.00	83.34	51.53	76.10	71.46	53.20
2018 Self-Constructed Peer Group (b)	100.00	86.64	55.75	81.24	75.12	53.95

*The stock price performance included in this graph is not necessarily indicative of future stock price performance.

(a) The 2017 Self-Constructed Peer Group includes the following twenty-one companies: Antero Resources Corp, Cabot Oil & Gas Corp, Chesapeake Energy Corp, Cimarex Energy Co, CNX Resources Corp, Concho Resources Inc., Continental Resources, Inc., Devon Energy Corp, EOG Resources, Inc., EXCO Resources, Inc., Marathon Oil Corp, National Fuel Gas Co, Newfield Exploration Co, Noble Energy, Inc., ONEOK, Inc., Pioneer Natural Resources Co, QEP Resources, Inc., Range Resources Corp, SM Energy Co, Southwestern Energy Co and Whiting Petroleum Corp. Energen Corp was included in the self-constructed peer group that served as the basis for the stock performance graph in the Company’s Annual Report on Form 10-K for the year ended December 31, 2017 but has been excluded from the 2017 Self-Constructed Peer Group because it was acquired.

(b) The 2018 Self-Constructed Peer Group includes the following nineteen companies: Anadarko Petroleum Corp, Antero Resources Corp, Apache Corp, Cabot Oil & Gas Corp, Chesapeake Energy Corp, Cimarex Energy Co, CNX Resources Corp, Concho Resources Inc., Continental Resources, Inc., Devon Energy Corp, Diamondback Energy, Inc., Encana Corp, EOG Resources, Inc., Hess Corp, Marathon Oil Corp, Newfield Exploration Co, Noble Energy, Inc., Pioneer Natural Resources Co and Range Resources Corp. The 2018 Self-Constructed Peer Group is the peer group that is used for the Company’s 2018 Incentive Performance Share Unit Program, which utilizes three-year total shareholder return against the peer group as one performance metric. Changes in the 2018 Self-Constructed Peer Group compared to the 2017 Self-Constructed Peer Group were made to reflect the change in size and business operations of the Company.

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Equity Compensation Plans
See Item 12, “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters,” for information relating to compensation plans under which the Company’s securities are authorized for issuance.

Item 6. Selected Financial Data

The Following selected financial data 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," both contained herein.

	As of and for the Years Ended December 31,				
	2018	2017	2016	2015	2014
	(Thousands, except per share amounts)				
Total operating revenues	$4,557,868	$3,091,020	$1,387,054	$2,131,664	$2,285,138
Amounts attributable to EQT Corporation:					
(Loss) income from continuing operations	$(2,380,920)	$1,387,029	$(531,493)	$(87,274)	$256,791
Income from discontinued operations, net of tax	136,352	121,500	78,510	172,445	130,174
Net (loss) income	$(2,244,568)	$1,508,529	$(452,983)	$85,171	$386,965
Earnings per share of common stock attributable to EQT Corporation:					
Basic:					
(Loss) income from continuing operations	$(9.12)	$7.40	$(3.18)	$(0.57)	$1.69
Income from discontinued operations	0.52	0.65	0.47	1.13	0.86
Net (loss) income	$(8.60)	$8.05	$(2.71)	$0.56	$2.55
Diluted:					
(Loss) income from continuing operations	$(9.12)	$7.39	$(3.18)	$(0.57)	$1.68
Income from discontinued operations	0.52	0.65	0.47	1.13	0.86
Net (loss) income	$(8.60)	$8.04	$(2.71)	$0.56	$2.54
Total assets	$20,721,344	$29,522,604	$15,472,922	$13,976,172	$12,035,353
Total long-term debt (including current portion)	$5,497,381	$5,997,329	$2,427,020	$2,299,942	$2,466,720
Cash dividends declared per share of common stock	$0.12	$0.12	$0.12	$0.12	$0.12

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

You should read the following discussion and analysis of financial condition and results of operations in conjunction with the consolidated financial statements, and the notes thereto, included in Item 8 of this Annual Report on Form 10-K. The Statements of Consolidated Operations and Consolidated Balance Sheets of Equitrans Midstream are reflected as discontinued operations for all periods presented. Prior periods have been recast to reflect this presentation. This recast also includes presenting certain transportation and processing expenses in continuing operations for all periods presented which were previously eliminated in consolidation prior to the Separation and Distribution. The cash flows related to Equitrans Midstream have not been segregated and are included within the Statements of Consolidated Cash Flows for all periods presented. See Note 2 to the Consolidated Financial Statements for amounts of the discontinued operations related to Equitrans Midstream which are included in the Statements of Consolidated Cash Flows.

Consolidated Results of Operations

Key Events in 2018:

- Completed the Separation and Distribution on November 12, 2018
- Completed the 2018 Divestitures
- Achieved annual sales volumes of 1,488 Bcfe and average daily sales volumes of 4,076 MMcfe/d. Adjusted for the impact of the 2018 Divestitures, total annual sales volumes were 1,447 Bcfe or 3,964 MMcfe/d.

See further discussion of the Separation, Distribution and the 2018 Divestitures as discussed in the "Key Events in 2018" section of Item 1, "Business."

Loss from continuing operations for 2018 was $2.4 billion, a loss of $9.12 per diluted share, compared with income from continuing operations of $1.4 billion, $7.39 per diluted share, in 2017. The $3.8 billion decrease was primarily attributable to $3.5 billion of impairments and losses on the sale of long-lived assets including: $2.7 billion associated with the 2018 Divestitures, goodwill impairment and higher lease impairments. Excluding these items, a $1.5 billion increase in operating revenues was offset by higher operating expenses including depreciation and depletion and transportation and processing expenses and higher interest expense as well as a lower tax benefit.

Income from continuing operations for 2017 was $1.4 billion, $7.39 per diluted share, compared with a loss from continuing operations of $0.5 billion, a loss of $3.18 per diluted share, in 2016. The $1.9 billion increase in income from continuing operations was primarily attributable to higher sales of natural gas, oil and NGLs, an income tax benefit recorded as a result of the lower federal corporate tax rate beginning in 2018 and a gain on derivatives not designated as hedges in 2017 compared to a loss in 2016, partly offset by higher operating expenses, higher interest expense and a loss on debt extinguishment in 2017.

See “Sales Volumes and Revenues” and “Operating Expenses” for a discussion of items impacting operating income and “Other Income Statement Items” for a discussion of other income statement items.

Average Realized Price Reconciliation

The following table presents detailed natural gas and liquids operational information to assist in the understanding of the Company’s consolidated operations, including the calculation of the Company's average realized price ($/Mcfe), which is based on adjusted operating revenues, a non-GAAP supplemental financial measure. Adjusted operating revenues is presented because it is an important measure used by the Company’s management to evaluate period-to-period comparisons of earnings trends. Adjusted operating revenues should not be considered as an alternative to total operating revenues. See “Reconciliation of Non-GAAP Financial Measures” for a reconciliation of adjusted operating revenues to total operating revenues.

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	Years Ended December 31,		
	2018 (e)	2017 (e)	2016
	(Thousands, unless noted)		
NATURAL GAS			
Sales volume (MMcf)	1,386,718	774,076	683,495
NYMEX price ($/MMBtu) (a)	$3.10	$3.09	$2.47
Btu uplift	$0.19	$0.27	$0.22
Natural gas price ($/Mcf)	$3.29	$3.36	$2.69
Basis ($/Mcf) (b)	(0.25)	(0.54)	(0.81)
Cash settled basis swaps (not designated as hedges) ($/Mcf)	$(0.08)	$0.01	$0.09
Average differential, including cash settled basis swaps ($/Mcf)	$(0.33)	$(0.53)	$(0.72)
Average adjusted price ($/Mcf)	$2.96	$2.83	$1.97
Cash settled derivatives (cash flow hedges) ($/Mcf)	—	0.01	0.13
Cash settled derivatives (not designated as hedges) ($/Mcf)	(0.07)	0.05	0.31
Average natural gas price, including cash settled derivatives ($/Mcf)	$2.89	$2.89	$2.41
Natural gas sales, including cash settled derivatives	$4,004,147	$2,237,234	$1,649,831
LIQUIDS			
NGLs (excluding ethane):			
Sales volume (MMcfe) (c)	63,247	74,060	57,243
Sales volume (Mbbls)	10,542	12,343	9,540
Price ($/Bbl)	$37.63	$31.59	$19.43
Cash settled derivatives (not designated as hedges) ($/Bbl)	(1.07)	(0.69)	—
Average NGL price, including cash settled derivatives ($/Bbl)	$36.56	$30.90	$19.43
NGLs sales	$385,364	$381,327	$185,405
Ethane:			
Sales volume (MMcfe) (c)	33,645	33,432	13,856
Sales volume (Mbbls)	5,607	5,572	2,309
Price ($/Bbl)	$8.09	$6.32	$5.08
Ethane sales	$45,339	$35,241	$11,742
Oil:			
Sales volume (MMcfe) (c)	4,079	5,952	4,373
Sales volume (Mbbls)	680	992	729
Price ($/Bbl)	$52.70	$40.70	$34.73
Oil sales	$35,825	$40,376	$25,312
Total liquids sales volume (MMcfe) (c)	100,971	113,444	75,472
Total liquids sales volume (Mbbls)	16,829	18,907	12,578
Liquids sales	$466,528	$456,944	$222,459
TOTAL PRODUCTION			
Total natural gas & liquids sales, including cash settled derivatives (d)	$4,470,675	$2,694,178	$1,872,290
Total sales volume (MMcfe)	1,487,689	887,520	758,967
Average realized price ($/Mcfe)	$3.01	$3.04	$2.47

(a) The Company’s volume weighted NYMEX natural gas price (actual average NYMEX natural gas price ($/MMBtu) was $3.09, $3.11 and $2.46 for the years ended December 31, 2018, 2017 and 2016, respectively).
(b) Basis represents the difference between the ultimate sales price for natural gas and the NYMEX natural gas price.
(c) NGLs, ethane and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods.
(d) Also referred to in this report as adjusted operating revenues, a non-GAAP supplemental financial measure.
(e) For the year ended December 31, 2018, results include operations acquired in the Rice Merger (defined in Note 3 to the Consolidated Financial Statements). For the year ended December 31, 2017, results include operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017.

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Reconciliation of Non-GAAP Financial Measures

The table below reconciles adjusted operating revenues, a non-GAAP supplemental financial measure, to total operating revenues, its most directly comparable financial measure calculated in accordance with GAAP.

Adjusted operating revenues (also referred to as total natural gas & liquids sales, including cash settled derivatives) is presented because it is an important measure used by the Company's management to evaluate period-over-period comparisons of earnings trends. Adjusted operating revenues as presented excludes the revenue impact of changes in the fair value of derivative instruments prior to settlement and the revenue impact of "Net marketing services and other". Management utilizes adjusted operating revenues to evaluate earnings trends because the measure reflects only the impact of settled derivative contracts and thus does not impact the revenue from natural gas sales with the often volatile fluctuations in the fair value of derivatives prior to settlement. Adjusted operating revenues also excludes "Net marketing services and other" because management considers these revenues to be unrelated to the revenues for its natural gas and liquids production. "Net marketing services and other" primarily includes the cost of and recoveries on pipeline capacity not used for the Company's sales volumes and revenues for gathering services. Management further believes that adjusted operating revenues as presented provides useful information to investors for evaluating period-over-period earnings trends.

Adjusted operating revenues	Years Ended December 31,		
	2018	2017	2016
	(Thousands, unless noted)		
Total operating revenues	$4,557,868	$3,091,020	$1,387,054
(Deduct) add back:			
Loss (gain) on derivatives not designated as hedges	178,591	(390,021)	248,991
Net cash settlements (paid) received on derivatives not designated as hedges	(225,279)	40,728	279,425
Premiums received (paid) for derivatives that settled during the year	435	2,132	(2,132)
Net marketing services and other	(40,940)	(49,681)	(41,048)
Adjusted operating revenues, a non-GAAP financial measure	$4,470,675	$2,694,178	$1,872,290
Total sales volumes (MMcfe)	1,487,689	887,520	758,967
Average realized price ($/Mcfe)	$3.01	$3.04	$2.47

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Sales Volumes and Revenues

	Years Ended December 31,				
	2018 (c)	2017 (c)	% change 2018 - 2017	2016	% change 2017 - 2016
Sales volume detail (MMcfe):					
Marcellus (a)	1,229,934	770,620	59.6	660,146	16.7
Ohio Utica	209,428	24,266	763.1	536	4,427.2
Other	48,327	92,634	(47.8)	98,285	(5.7)
Total sales volumes (b)	1,487,689	887,520	67.6	758,967	16.9
Average daily sales volumes (MMcfe/d)	4,076	2,432	67.6	2,074	17.3
Average realized price ($/Mcfe)	$3.01	$3.04	(1.0)	$2.47	23.1
Revenues (thousands):					
Sales of natural gas, oil and NGLs	$4,695,519	$2,651,318	77.1	$1,594,997	66.2
Net marketing services and other	40,940	49,681	(17.6)	41,048	21.0
(Loss) gain on derivatives not designated as hedges	(178,591)	390,021	(145.8)	(248,991)	(256.6)
Total operating revenues	$4,557,868	$3,091,020	47.5	$1,387,054	122.8

(a) Includes Upper Devonian wells.

(b) NGLs, ethane and crude oil were converted to Mcfe at the rate of six Mcfe per barrel for all periods.

(c) For the year ended December 31, 2018, results include operations acquired in the Rice Merger (defined in Note 3 to the Consolidated Financial Statements). For the year ended December 31, 2017, results include operations acquired in the Rice Merger for the period of November 13, 2017 through December 31, 2017.

Total operating revenues were $4,557.9 million for 2018 compared to $3,091.0 million for 2017. Sales of natural gas, oil and NGLs increased as a result of a 68% increase in sales volumes in 2018, which was primarily a result of the Rice Merger and increased production from the 2016 and 2017 drilling programs, partly offset by the 2018 Divestitures and the normal production decline in the Company’s producing wells. The average realized price decreased in 2018 compared to 2017 due to a decrease in the average NYMEX natural gas price net of cash settled derivatives and a decrease in higher priced liquids sales as a result of the 2018 Divestitures partly offset by an increase in the average natural gas differential. The Company paid $225.3 million and received $40.7 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2018 and 2017, respectively, that are included in the average realized price but are not in GAAP operating revenues. Changes in fair market value of derivative instruments prior to settlement are recognized in (loss) gain on derivatives not designated as hedges. The increase in the average differential primarily related to higher prices during the first quarter of 2018 at sales points in the United States Northeast where colder weather led to increased demand, higher Appalachian Basin basis as well as increased sales volumes at higher priced Gulf Coast and Midwest markets accessible through the Company’s increased transportation portfolio following the Rice Merger.

Total operating revenues for 2018 included a $178.6 million loss on derivatives not designated as hedges compared to a $390.0 million gain on derivatives not designated as hedges in 2017. The loss in 2018 primarily related to decreases in the fair market value of the Company’s 2018 NYMEX swaps and options and basis swaps from December 31, 2017 through the date of settlement as a result of increases in the underlying prices throughout this period. These losses were partly offset by increases in the fair market value of the Company's open NYMEX positions at December 31, 2018 due to a decrease in forward NYMEX during 2018.

Total operating revenues were $3,091.0 million for 2017 compared to $1,387.1 million for 2016. Sales of natural gas, oil and NGLs increased as a result of higher average realized price and a 17% increase in sales volumes in 2017. EQT received $40.7 million and $279.4 million of net cash settlements for derivatives not designated as hedges for the years ended December 31, 2017 and 2016, respectively, that are included in the average realized price but are not in GAAP operating revenues. The increase in sales volumes was primarily the result of acquisition activity, including the Rice Merger, as well as increased production from the 2015 and 2016 drilling programs, primarily in the Marcellus play, partially offset by the normal production decline in the Company's producing wells in 2017.

The $0.57 per Mcfe increase in the average realized price for the year ended December 31, 2017 was primarily due to the
increase in the average NYMEX natural gas price net of cash settled derivatives of $0.29 per Mcf, an increase in the average natural gas differential of $0.19 per Mcf and an increase in liquids prices. The improvement in the average differential primarily

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related to more favorable basis partly offset by unfavorable cash settled basis swaps. During 2017, basis improved in the Appalachian Basin and at sales points reached through the Company's transportation portfolio, particularly in the United States Northeast. In addition, the Company started flowing its produced volumes to its Rockies Express pipeline capacity and Texas Eastern Transmission Gulf Markets pipeline capacity in the fourth quarter of 2016, which resulted in a favorable impact to basis for the year ended December 31, 2017 compared to the year ended December 31, 2016.

Total operating revenues for the year ended December 31, 2017 included a $390.0 million gain on derivatives not designated as hedges compared to a $249.0 million loss on derivatives not designated as hedges for the year ended December 31, 2016. The gains for the year ended December 31, 2017 primarily related to increases in the fair market value of the Company's NYMEX swaps due to decreased NYMEX prices, partly offset by decreases in the fair market value of its basis swaps due to increased basis prices.

Operating Expenses

The following presents information about certain of the Company's operating expenses for each of the last three years.

	Years Ended December 31,				
	2018	2017	% change 2018 - 2017	2016	% change 2017 - 2016
	(Thousands, unless otherwise noted)				
Per Unit ($/Mcfe)					
Gathering	$0.54	$0.55	(1.8)	$0.55	—
Transmission	$0.49	$0.56	(12.5)	$0.45	24.4
Processing	$0.11	$0.20	(45.0)	$0.16	25.0
Lease operating expenses (LOE), excluding production taxes	$0.07	$0.13	(46.2)	$0.15	(13.3)
Production taxes	$0.06	$0.08	(25.0)	$0.08	—
Exploration	$—	$0.02	(100.0)	$0.01	100.0
Selling, general and administrative (SG&A)	$0.19	$0.24	(20.8)	$0.29	(17.2)
Production depletion	$1.04	$1.04	—	$1.06	(1.9)
Operating expenses:					
Gathering	$801,746	$489,610	63.8	$413,758	18.3
Transmission	$729,537	$495,635	47.2	$341,569	45.1
Processing	$165,718	$179,538	(7.7)	$124,864	43.8
LOE, excluding production taxes	$100,644	$112,501	(10.5)	$111,853	0.6
Production taxes	$95,131	$68,848	38.2	$62,317	10.5
Exploration	$6,765	$17,565	(61.5)	$4,663	276.7
Selling, general and administrative	$284,220	$208,986	36.0	$218,946	(4.5)

Gathering. Gathering expense increased on an absolute basis in 2018 compared to 2017 due to the 68% increase in sales volumes partly offset by a lower gathering rate per unit on gathering capacity acquired in the Rice Merger, which also decreased the rate per Mcfe. Gathering expense increased in 2017 compared to 2016 on an absolute basis due to increased gathering capacity and expense from the Company's 2016 and 2017 acquisitions.

Transmission. Transmission expense increased on an absolute basis in 2018 compared to 2017 due to increased third party capacity incurred to move the Company's natural gas out of the Appalachian Basin, primarily firm capacity acquired in connection with the Rice Merger, the Company's capacity on the Rover pipeline, which started in 2018, as well as an increase in the Company’s firm capacity on Columbia Gas Transmission pipeline which increased in the first quarter of 2018. These increases were partly offset by reduced firm capacity costs as a result of the Huron Divestiture. Transmission expense per Mcfe decreased as a result of increased sales volumes in 2018. Transmission expense increased on an absolute basis in 2017 compared to 2016 due to increased capacity incurred to move the Company’s natural gas out of the Appalachian Basin. During the fourth quarter of 2016, the Company started flowing its produced volumes to its Rockies Express and Texas Eastern Transmission Gulf Markets pipeline capacity. Additionally, the Company's firm capacity on Rockies Express pipeline increased in the first quarter of 2017. Firm capacity acquired in connection with the Rice Merger also increased transmission expenses by approximately $24.2 million. Transmission expense per Mcfe increased in 2017 compared to 2016 as the impact of the above items exceeded the 17% growth in sales volumes during the period.

Processing. Processing expense decreased on an absolute basis in 2018 compared to 2017 primarily as a result of the 2018 Divestitures and decreased on a per Mcfe basis as a result of a 68% increase in sales volumes when combined with the impact

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of the 2018 Divestitures. Processing expense increased on an absolute basis in 2017 compared to 2016 as a result of increased processing capacity acquired through acquisitions and higher volumes processed, which is consistent with higher ethane and NGLs sales volumes of approximately 50% in 2017 compared to 2016. These factors also contributed to an increase in processing expense on a per Mcfe basis as they exceeded the offsetting impact of growth in sales volumes during the period.

LOE. LOE decreased on an absolute and per Mcfe basis in 2018 compared to 2017 primarily as a result of the 2018 Divestitures and growth in sales volumes in 2018 partly offset by higher salt water disposal costs and personnel costs due to increased activity in the Company's Marcellus and Utica operations. Excluding the costs related to the 2018 Divestitures, per unit LOE was $0.05 per Mcfe in 2018 as compared to a divestiture adjusted $0.07 per Mcfe in 2017. LOE increased on an absolute basis in 2017 compared to 2016 primarily due to increased salt water disposal costs as a result of increased activity in the Company’s Marcellus operations, but decreased on a per Mcfe basis due to the growth in sales volumes during the period.

Production taxes. Production taxes increased on an absolute basis in 2018 compared to 2017 primarily as a result of the significant increase in the number of wells subject to the Pennsylvania Impact Fee as well as the increased asset base and production volumes in Ohio following the Rice Merger, partly offset by the lower asset base and production volumes in Kentucky, West Virginia, Virginia and Texas following the 2018 Divestitures. Production taxes decreased on a per Mcfe basis in 2018 compared to 2017 due to an increase in sales volumes. Production taxes increased on an absolute basis in 2017 compared to 2016 as a result of higher market prices in 2017 in combination with an increase in the number of wells subject to the Pennsylvania Impact Fee as well as an increased asset base and production from acquisitions.

Exploration. Exploration expense decreased in 2018 compared to 2017 and increased in 2017 compared to 2016 on an absolute and per Mcfe basis, primarily due to expenses related to an exploratory well in a non-core operating area classified as a dry hole in 2017.

SG&A. SG&A expense increased on an absolute basis in 2018 compared to 2017, primarily due to increased legal reserves, increased charitable contributions to the EQT Foundation and increased personnel costs associated with workforce reductions. SG&A expense decreased on an absolute basis in 2017 compared 2016, primarily due to lower pension expense related to the termination of the EQT Corporation Retirement Plan for Employees in the second quarter of 2016, lower legal reserves in 2017, a reduction to the reserve for uncollectible accounts, and the absence of costs related to the consolidation of the Company’s Huron operations in 2016. This was partly offset by higher costs associated with acquisitions. SG&A expense per Mcfe decreased in 2018 compared to 2017 and in 2017 compared 2016 due to an increase in sales volumes for each respective period.

Depreciation and depletion. Depreciation and depletion increased as a result of higher produced volumes in 2018, partly offset by lower depreciation as a result of the 2018 Divestitures. Depreciation and depletion increased as a result of higher produced volumes partly offset by a lower overall depletion rate in 2017 compared to 2016.

	Years Ended December 31,				
	2018	2017	% change 2018 - 2017	2016	% change 2017 - 2016
	(Thousands)				
Depreciation and depletion					
Production depletion	$1,546,136	$924,430	67.3	$803,883	15.0
Other depreciation and depletion	22,902	46,555	(50.8)	52,568	(11.4)
Total depreciation and depletion	$1,569,038	$970,985	61.6	$856,451	13.4

Impairment of long-lived assets. Impairment of long-lived assets increased $2,710.0 million in 2018 compared 2017, related to the 2018 Divestitures. See Note 8 to the Consolidated Financial Statements for a discussion of the asset impairment.

Impairment of goodwill. Impairment of goodwill was $530.8 million in 2018. As a result of the Company's single reporting unit's fair value falling below its carrying value, the full carrying value of goodwill was written off and recorded as impairment of goodwill. See Note 1 to the Consolidated Financial Statements for a discussion of the goodwill impairment.

Lease impairments and expirations. Lease impairments and expirations increased in 2018 compared to 2017, primarily due to an increase in the amount of leases that expired during 2018 that were primarily located in non-contiguous or non-core development areas and for impairments of leases not yet expired that are not expected to be drilled or extended prior to expiration during 2019. The increase in the number of leases expiring in 2018 and 2019 is primarily due to acquisition activity completed by the Company throughout 2016 and 2017 in addition to the Rice Merger. Lease impairments and expirations decreased in 2017 compared to 2016, primarily due to a decrease in the number of leases that expired in 2017 and impairments recorded in 2016 for leases not yet expired that would not be drilled prior to expiration.

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Transaction costs. Transaction costs in 2018 and 2017 were primarily legal and banking fees related to the Rice Merger. Transaction costs associated with the Separation and Distribution and a proportionate share of the transaction costs associated with the Rice Merger were allocated to discontinued operations as described in Note 2 to the Company's Consolidated Financial Statements.

Amortization of intangible assets. In connection with the Rice Merger, the Company obtained intangible assets composed of non-compete agreements with former Rice executives. Amortization expense for 2018 and 2017 was $41.4 million and $5.4 million, respectively, for these non-compete agreements, which are being amortized over three years.

Other Income Statement Items

Other expense. Other expense increased in 2018 as compared to 2017, primarily due to changes in the fair market value of the Company's investment in Equitrans Midstream which generated an unrealized loss of $72.4 million.

The Company initiated its investments in trading securities in 2016 to enhance returns on a portion of its significant cash balance at that time. For the years ended December 31, 2017 and 2016 the Company recorded realized losses of $2.6 million and unrealized gains of $1.5 million, respectively, on these debt securities. As of March 31, 2017, the Company closed its positions on all trading securities.

Loss on debt extinguishment. In 2017, the Company recorded loss on debt extinguishment of $12.6 million in connection with the early extinguishment on November 3, 2017 of the $200 million aggregate principal amount 5.15% Senior Notes due 2018 and $500 million aggregate principal amount 6.50% Senior Notes due 2018. The loss consists of $12.2 million paid in excess of par in order to extinguish the debt prior to maturity and $0.4 million in non-cash expenses related to the write-off of unamortized financing costs and discounts.

Interest expense. Interest expense increased $61.0 million in 2018 compared to 2017 primarily driven by an additional $74.3 million of interest incurred on Senior Notes issued in October 2017 and an additional $24.0 million of interest incurred on credit facility borrowings partly offset by a $35.9 million decrease due to the early extinguishment of certain Senior Notes and a decrease of $5.1 million related to expense incurred in 2017 on the Company's senior unsecured bridge loans. Interest expense increased $36.8 million for the year ended December 31, 2017 compared to the year ended December 31, 2016 primarily driven by $23.6 million of interest incurred on Senior Notes issued in October 2017, $5.1 million of expense related to the bridge financing commitment for the Rice Merger and $5.5 million of interest incurred on credit facility borrowings partly offset by a $7.0 million decrease due to the early extinguishment of Senior Notes. See Note 10 to the Consolidated Financial Statements for discussion of the borrowings and weighted average interest rates for the Company's credit facility.

Income tax (benefit). On December 22, 2017, Congress enacted the law known as the Tax Cuts and Jobs Act of 2017 (the Tax Cuts and Jobs Act), which made significant changes to U.S. federal income tax law, including lowering the federal corporate tax rate to 21% from 35% beginning January 1, 2018. As a result of the change in the corporate tax rate, the Company recorded a deferred tax benefit of $1.2 billion during the year ended December 31, 2017 to revalue its existing net deferred tax liabilities to the lower rate.

The Company applied the guidance in SAB 118 when accounting for the enactment-date effects of the Tax Cuts and Jobs Act in 2017 and throughout 2018. At December 31, 2017, the Company had not completed the accounting for all of the enactment-date income tax effects of the legislation under ASC 740, Income Taxes, for the following aspects: remeasurement of deferred tax assets and liabilities and incentive-based compensation limitations. At December 31, 2018, the Company completed the accounting for all of the enactment-date income tax effects of the Tax Cuts and

Jobs Act. During 2018, the Company recognized adjustments of $5.3 million to the provisional amounts recorded at December 31, 2017 and included these adjustments as a component of income tax benefit from continuing operations. The additional expense is primarily the result of adjustments to the increased limitations on deductible executive compensation.

For federal income tax purposes, the Company continues to have the ability to deduct a portion of its drilling costs as intangible drilling costs (IDCs) in the year incurred after the Tax Cuts and Jobs Act. For periods prior to January 1, 2018, IDCs were limited for purposes of the alternative minimum tax (AMT) and this has resulted in the Company paying AMT even when generating or utilizing a net operating loss carryforward (NOL) to offset regular taxable income. For periods after January 1, 2018, AMT has been repealed by the Tax Cuts and Jobs Act, and the Company has the ability to utilize any existing AMT credit carryforwards against its current federal tax liability and then receive a refund equal to 50% of the remaining balance in each tax year from 2018 through 2020 with any remaining AMT credit carryforward in 2021 being fully refunded . As a result, the Company will receive a Federal tax refund for the 2018 tax year of $128 million and has $295 million of AMT credit carryforward remaining, net of valuation allowances for sequestration of $13 million, as of December 31, 2018. As a result of an announcement by the IRS in January 2019 reversing its position that AMT refunds were subject to sequestration by the federal government at a rate equal to 6.2% of the refund, the Company will reverse the related valuation allowance in the first quarter of 2019.

The Tax Cuts and Jobs Act limits the utilization of NOLs generated after December 31, 2017 that are carried into future years to 80% of taxable income and limits the deductibility of interest expense. As a result of the interest limitation, the Company recorded a valuation allowance in 2018 for a portion of the interest expense limit imposed for separate company state income tax purposes.

See Note 9 to the Consolidated Financial Statements for further discussion of the Company’s income tax (benefit) expense, including a reconciliation between income tax (benefit) expense calculated at the current federal statutory rate and the effective tax rate reflected in the Company's financial statements for each of the years ended December 31, 2018, 2017 and 2016.

Outlook

See Item 1, “Business” for the Company's outlook.

Impairment of Oil and Gas Properties and Goodwill

See “Critical Accounting Policies and Estimates” and Note 1 to the Consolidated Financial Statements for a discussion of the Company’s accounting policies and significant assumptions related to impairment of the Company’s oil and gas properties and goodwill.

See Item 1A, "Risk Factors - Natural gas, NGLs and oil price declines have resulted in impairment of certain of our non-core assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, including long lived intangible assets, which could materially and adversely affect our results of operations in future periods.”

Capital Resources and Liquidity

The Statement of Consolidated Cash Flows has not been restated for discontinued operations, therefore the discussion below concerning cash from operating activities, investing activities and financing activities includes the results of both continuing and discontinued operations through the completion of the Separation and Distribution on November 12, 2018. See Note 2 to the Consolidated Financial Statements for amounts attributable to discontinued operations which are included in the Statements of Consolidated Cash Flows.

Although the Company cannot provide any assurance, it believes cash flows from operating activities and availability under the revolving credit facility should be sufficient to meet the Company's cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures and commitments for at least the next 12 months.

Operating Activities

Net cash provided by operating activities increased $1,338.6 million for 2018 as compared to 2017. The increase was primarily driven by higher operating revenues partly offset by increased cash operating expenses for which contributing factors are discussed in the "Consolidated Results of Operations" section herein, the timing of payments between the two periods and cash settlements paid on derivatives not designated as hedges.

Net cash provided by operating activities increased $573.4 million for 2017 as compared to 2016. The increase in cash flows provided by operating activities was primarily driven by higher operating income for which contributing factors are discussed in the "Consolidated Results of Operations" section herein and the timing of payments between the two periods, partly offset by lower cash settlements received on derivatives not designated as hedges.

The Company's cash flows from operating activities will be impacted by future movements in the market price for commodities. The Company is unable to predict these future price movements outside of the current market view as reflected in forward strip pricing. Refer to Item 1A, "Risk Factors - Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect upon our revenue, profitability, future rate of growth, liquidity and financial position." for further information.

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Investing Activities

Net cash used in investing activities decreased $223.0 million for 2018 as compared to 2017. The decrease was primarily due to investment in the Rice Merger in 2017, a decrease in capital expenditures for other property acquisitions and proceeds from the 2018 Divestitures partly offset by an increase in capital expenditures primarily for reserve development and midstream infrastructure attributable to discontinued operations, higher capital contributions to Mountain Valley Pipeline, LLC (the MVP Joint Venture) and cash received from the sale of trading securities in 2017.

Net cash used in investing activities increased $1,315.6 million for 2017 as compared to 2016. The increase was primarily due to investment in the Rice Merger, an increase in capital expenditures primarily for reserve development and higher capital contributions to the MVP Joint Venture, partly offset by a decrease in capital expenditures for other property acquisitions, cash received from the sale of trading securities and lower capital expenditures on midstream infrastructure attributable to discontinued operations. See Note 3 to the Consolidated Financial Statements for further discussion of the Rice Merger.

Capital Expenditures

	Years Ended December 31,		
	2018	2017	2016
	(Millions)		
Reserve development	$ 2,255	$ 1,208	$ 623
Land and lease	228	178	124
Capitalized overhead	130	115	115
Capitalized interest	29	21	19
Other production infrastructure	42	43	36
Property acquisitions	48	829	1,160
Other corporate items	7	13	3
Total capital expenditures from continuing operations	$ 2,739	$ 2,407	$ 2,080
Midstream infrastructure (a)	733	380	585
Total capital expenditures	$ 3,472	$ 2,787	$ 2,665
Less: non-cash (b)	(260)	17	74
Total cash capital expenditures	$ 3,732	$ 2,770	$ 2,591

(a) Capital expenditures related to midstream infrastructure are presented as discontinued operations as described in Note 2 to the Company's Consolidated Financial Statements.

(b) Represents the net impact of non-cash capital expenditures including capitalized non-cash share-based compensation expense, accruals and receivables from working interest partners. The impact of accrued capital expenditures includes the reversal of the prior period accrual as well as the current period estimate. The year ended December 31, 2018 included $14.4 million of measurement period adjustments for 2017 acquisitions. The year ended December 31, 2017 included $10.0 million of non-cash capital expenditures related to 2017 acquisitions and $(14.3) million of measurement period adjustments for 2016 acquisitions. The year ended December 31, 2016 included $87.6 million of non-cash capital expenditures related to 2016 acquisitions.

The Company spud 153 gross wells in 2018, including 117 horizontal Marcellus wells, 5 horizontal Upper Devonian wells and 31 horizontal Utica wells. The Company spud 201 gross wells in 2017, including 144 horizontal Marcellus wells, 49 horizontal Upper Devonian wells, seven horizontal Utica wells and one other well. The Company spud 135 gross wells in 2016, including 117 horizontal Marcellus wells, 13 horizontal Upper Devonian wells and four horizontal Utica wells. The increase in capital expenditures for well development in 2018 was driven primarily by the timing of drilling and completions activities between years, service cost increases and inefficiencies resulting from higher activity levels and the learning curve on ultra-long laterals, partly offset by a decrease in property acquisitions. The increase in capital expenditures for well development in 2017 was driven primarily by the timing of drilling and completions activities between years and an increase in wells spud, partly offset by a decrease in property acquisitions. These acquisitions are discussed in Note 7 to the Consolidated Financial Statements.

Capital expenditures for the midstream infrastructure are primarily related to expansion capital expenditures, which are expenditures incurred for capital improvements that EQM expects to increase its operating income or operating capacity over the long term. The increase in expansion capital expenditures in 2018 as compared to 2017 primarily related to new gathering and transmission expansion projects in 2018, including the the Hammerhead project, the Equitrans, L.P. expansion project and various

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wellhead gathering expansion projects. The decrease in expansion capital expenditures in 2017 as compared to 2016 primarily related to the Ohio Valley Connector, which was placed into service in the fourth quarter of 2016.

Financing Activities

Cash flows provided by financing activities totaled $859.0 million for 2018 as compared to $1,533.1 million for 2017. During 2018, the primary source of financing cash flows was net proceeds from an EQM senior notes offering and the primary uses of financing cash flows were repurchases and retirements of common stock, distributions to noncontrolling interests, net repayments of credit facility borrowings, EQM's acquisition of a 25% ownership interest in Strike Force Midstream LLC, net cash transferred as part of the Separation and Distribution, dividends paid and cash paid for taxes on share-based incentive awards. During 2017, the primary sources of financing cash flows were net proceeds from the 2017 Notes Offering (defined in Note 10 to the Consolidated Financial Statements) and net borrowings on credit facilities. The primary uses of financing cash flows during 2017 were redemptions and repayment of Rice's debt in connection with the closing of the Rice Merger, redemption of the Company's Senior Notes and distributions to noncontrolling interests.

On January 16, 2019, the Board of Directors of the Company declared a quarterly cash dividend of three cents per share, payable March 1, 2019, to the Company’s shareholders of record at the close of business on February 15, 2019.

Cash flows provided by financing activities totaled $1,533.1 million for 2017 as compared to $1,399.5 million for 2016. During 2016, the primary sources of financing cash flows were net proceeds from its public offerings of common stock, EQM's public offerings of its common units and proceeds received from the issuance of EQM senior notes. The primary uses of financing cash flows during 2016 were net EQM credit facility repayments and distributions to noncontrolling interests.

The Company may from time to time seek to repurchase its outstanding debt securities. Such repurchases, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual and legal restrictions and other factors.

Revolving Credit Facility

The Company primarily utilizes borrowings under its revolving credit facility to fund working capital needs, timing differences between capital expenditures and other cash uses and cash flows from operating activities and required margin deposits on derivative commodity instruments. Margin deposit requirements vary based on natural gas commodity prices, the Company's credit ratings and the amount and type of derivative commodity instruments. See Note 10 to the Consolidated Financial Statements for further discussion of the Company's credit facility.

Security Ratings and Financing Triggers

The table below reflects the credit ratings for debt instruments of the Company at December 31, 2018. Changes in credit ratings may affect the Company’s cost of short-term debt through interest rates and fees under its lines of credit. These ratings may also affect collateral requirements under derivative instruments, pipeline capacity contracts and rates available on new long-term debt and access to the credit markets.

Rating Service	Senior Notes	Outlook
Moody’s Investors Service (Moody's)	Baa3	Stable
Standard & Poor’s Ratings Service (S&P)	BBB-	Stable
Fitch Ratings Service (Fitch)	BBB-	Stable

The Company’s credit ratings are subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. The Company cannot ensure that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn by a credit rating agency if, in its judgment, circumstances so warrant. If any credit rating agency downgrades the ratings, particularly below investment grade, the Company’s access to the capital markets may be limited, borrowing costs and margin deposits on the Company’s derivative contracts would increase, counterparties may request additional assurances, including collateral, and the potential pool of investors and funding sources may decrease. The required margin on the Company’s derivative instruments is also subject to significant change as a result of factors other than credit rating, such as gas prices and credit thresholds set forth in agreements between the hedging counterparties and the Company. Investment grade refers to the quality of a company's credit as assessed by one or more credit rating agencies. In order to be considered investment grade, a company must be rated BBB- or higher by S&P, Baa3 or higher by Moody's, and BBB- or higher by Fitch. Anything below these ratings is considered non-investment grade.

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The Company’s debt agreements and other financial obligations contain various provisions that, if not complied with, could result in termination of the agreements, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the debt agreements relate to maintenance of a debt-to-total capitalization ratio, limitations on transactions with affiliates, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. The Company’s credit facility contains financial covenants that require a total debt-to-total capitalization ratio no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income (OCI). As of December 31, 2018, the Company was in compliance with all debt provisions and covenants.

Commodity Risk Management

The substantial majority of the Company’s commodity risk management program is related to hedging sales of the Company’s produced natural gas. The Company’s overall objective in this hedging program is to protect cash flow from undue exposure to the risk of changing commodity prices. The derivative commodity instruments currently utilized by the Company are primarily swaps, calls and puts.

As of January 31, 2019, the approximate volumes and prices of the Company’s NYMEX hedge positions through 2023 are:

	2019 (a)	2020	2021	2022	2023
Swaps					
Volume (MMDth)	751	567	296	136	61
Average Price($/Dth)	$2.94	$2.82	$2.78	$2.75	$2.74
Calls - Net Short					
Volume (MMDth)	336	157	37	22	7
Average Short Strike Price ($/Dth)	$3.38	$3.15	$3.25	$3.20	$3.18
Puts - Net Long					
Volume (MMDth)	40	—	10	—	—
Average Long Strike Price ($/Dth)	$2.97	$—	$2.71	$—	$—
Fixed Price Sales (b)					
Volume (MMDth)	123	10	—	—	—
Average Price ($/Dth)	$3.01	$2.77	$—	$—	$—

(a) Full year 2019
(b) The difference between the fixed price and NYMEX are included in average differential on the Company’s price reconciliation under "Consolidated Results of Operations." The fixed price natural gas sales agreements can be physically or financially settled.

For 2019, 2020, 2021, 2022 and 2023, the Company has natural gas sales agreements for approximately 33 MMDth, 13 MMDth, 18MMDth, 18MMDth and 18MMDth, respectively, that include average NYMEX ceiling prices of $3.37, $3.68, $3.17, $3.17 and $3.17, respectively. Currently, the Company has also entered into derivative instruments to hedge basis and a limited number of contracts to hedge its NGLs exposure. The Company may also use other contractual agreements in implementing its commodity hedging strategy.

See Item 7A, “Quantitative and Qualitative Disclosures About Market Risk,” and Note 5 to the Consolidated Financial Statements for further discussion of the Company’s hedging program.

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Other Items

Off-Balance Sheet Arrangements

See Note 16 to the Consolidated Financial Statements for further discussion of the Company’s guarantees.

Schedule of Contractual Obligations

The table below presents the Company’s long-term contractual obligations as of December 31, 2018 in total and by periods.

	Total	2019	2020-2021	2022-2023	2024+
	(Thousands)				
Purchase obligations [(a)]	$23,566,215	$1,363,229	$3,458,560	$3,536,351	$15,208,075
Long-term debt, including current portion	4,724,920	704,661	1,795,421	771,354	1,453,484
Interest payments on debt [(b)]	797,638	163,134	255,842	143,682	234,980
Credit facility borrowings [(c)]	800,000	—	—	800,000	—
Operating leases [(d)]	109,853	70,248	16,816	16,797	5,992
Other liabilities [(e)]	50,809	12,990	28,976	1,786	7,057
Total contractual obligations	$30,049,435	$2,314,262	$5,555,615	$5,269,970	$16,909,588

(a) Purchase obligations are primarily commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines, some of which extend up to 20 years or longer. The Company has entered into agreements to release some of its capacity. Purchase obligations also include commitments for processing capacity in order to extract heavier liquid hydrocarbons from the natural gas stream.

(b) Interest payments exclude interest related to the credit facility borrowings and the Floating Rate Notes (defined in Note 10 to the Consolidated Financial Statements) as the interest rates on the Company's credit facility and the Floating Rate Notes are variable.

(c) Credit facility borrowings were classified based on the termination dates of the Company's credit facility.

(d) Operating leases are primarily entered into for dedicated drilling rigs in support of the Company’s drilling program and various office locations and warehouse buildings. The Company has agreements with several drillers to provide drilling equipment and services to the Company over the next year. These obligations were approximately $60.0 million as of December 31, 2018. The obligations for the Company’s various office locations and warehouse buildings were approximately $49.8 million as of December 31, 2018.

(e) Other liabilities primarily represents commitments for estimated payouts as of December 31, 2018 for various EQT liability stock award plans. See “Critical Accounting Policies and Estimates” below and Note 13 to the Consolidated Financial Statements for further discussion regarding factors that affect the ultimate amount of the payout of these obligations.

As discussed in Note 9 to the Consolidated Financial Statements, the Company had a total reserve for unrecognized tax benefits at December 31, 2018 of $315.3 million, of which $88.2 million is offset against deferred tax assets since it would primarily reduce the general business tax credit carryforwards. The Company is currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities; therefore, this amount has been excluded from the schedule of contractual obligations.

Commitments and Contingencies

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal and other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the Company's financial condition, results of operations or liquidity. See Note 15 to the Consolidated Financial Statements for further discussion of the Company's commitments and contingencies.

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Recently Issued Accounting Standards

The Company's recently issued accounting standards are described in Note 1 to the Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K.

Critical Accounting Policies and Estimates

The Company’s significant accounting policies are described in Note 1 to the Consolidated Financial Statements. The discussion and analysis of the Consolidated Financial Statements and results of operations are based upon the Company’s Consolidated Financial Statements, which have been prepared in accordance with GAAP. The preparation of the Consolidated Financial Statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosure of contingent assets and liabilities. The following critical accounting policies, which were reviewed by the Company’s Audit Committee, relate to the Company’s more significant judgments and estimates used in the preparation of its Consolidated Financial Statements. Actual results could differ from those estimates.

Accounting for Oil and Gas Producing Activities: The Company uses the successful efforts method of accounting for its oil and gas producing activities.

The carrying values of the Company’s proved oil and gas properties are reviewed for impairment generally on a field-by-field basis when events or circumstances indicate that the remaining carrying value may not be recoverable. The estimated future cash flows used to test those properties for recoverability are based on proved and, if determined reasonable by management, risk-adjusted probable reserves, utilizing assumptions generally consistent with the assumptions utilized by the Company's management for internal planning and budgeting purposes, including, among other things, the intended use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, adjusted accordingly for basis differentials, future operating costs and inflation, some of which are interdependent. Proved oil and gas properties that have carrying amounts in excess of estimated future cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rates and other assumptions that marketplace participants would use in their estimates of fair value.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. The likelihood of an impairment of unproved oil and gas properties increases as the expiration of a lease term approaches if drilling activity has not commenced. If it is determined that the Company does not intend to drill on the property prior to expiration or does not have the intent and ability to extend, renew, trade, or sell the lease prior to expiration, an impairment expense is recorded.

The Company believes that the accounting estimate related to the accounting for oil and gas producing activities is a “critical accounting estimate” as the evaluations of impairment of proved properties involve significant judgment about future events such as future sales prices of natural gas and NGLs, future production costs, estimates of the amount of natural gas and NGLs recorded and the timing of those recoveries. See "Impairment of Oil and Gas Properties and Goodwill" above and Note 1 to the Consolidated Financial Statements for additional information regarding the Company’s impairments of proved and unproved oil and gas properties.

Oil and Gas Reserves: Proved oil and gas reserves, as defined by SEC Regulation S-X Rule 4-10, are those quantities of oil and gas which, by analysis of geoscience 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 Company’s estimates of proved reserves are made and reassessed annually using geological and reservoir data as well as production performance data. Reserve estimates are prepared and updated by the Company’s engineers and audited by the Company’s independent engineers. Revisions may result from changes in, among other things, reservoir performance, development plans, prices, operating costs, economic conditions and governmental restrictions. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits sooner. A material change in the estimated volumes of reserves could have an impact on the depletion rate calculation and the Company's financial statements.

The Company estimates future net cash flows from natural gas, NGLs and oil reserves based on selling prices and costs using a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period, which is subject to change in subsequent periods. Operating costs, production and ad valorem taxes and future development costs are based on current costs with no escalation. Income tax expense is computed using future

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statutory tax rates and giving effect to tax deductions and credits available under current laws and which relate to oil and gas producing activities.

The Company believes that the accounting estimate related to oil and gas reserves is a "critical accounting estimate" because the Company must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the estimated timing of development expenditures. Future results of operations and strength of the balance sheet for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See "Impairment of Oil and Gas Properties and Goodwill" above for additional information regarding the Company's oil and gas reserves.

Income Taxes: The Company recognizes deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the Company's Consolidated Financial Statements or tax returns.

The Company has recorded deferred tax assets principally resulting from federal and state NOL carryforwards, an AMT credit carryforward, other federal tax credit carryforwards, unrealized capacity contract loss, incentive compensation and investment in securities. The Company has established a valuation allowance against a portion of the deferred tax assets related to the federal and state NOL carryforwards and AMT credit carryforward, as it is believed that it is more likely than not that certain deferred tax assets will not all be realized. As a result of an announcement by the IRS in January 2019 reversing its prior position that AMT refunds were subject to sequestration by the Government at a rate equal to 6.2% of the refund, the Company will reverse the related valuation allowance in the first quarter of 2019. In addition, a valuation allowance was recorded for a portion of the interest limitation disallowance imposed with the Tax Cuts and Jobs Act due to separate company reporting requirements. No other significant valuation allowances have been established, as it is believed that future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize these deferred tax assets. Any determination to change the valuation allowance would impact the Company's income tax expense and net income in the period in which such a determination is made.

The Company also estimates the amount of financial statement benefit to record for uncertain tax positions as described in Note 9 to the Company's Consolidated Financial Statements.

The Company believes that accounting estimates related to income taxes are "critical accounting estimates" because the Company must assess the likelihood that deferred tax assets will be recovered from future taxable income and exercise judgment regarding the amount of financial statement benefit to record for uncertain tax positions. When evaluating whether or not a valuation allowance must be established on deferred tax assets, the Company exercises judgment in determining whether it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized. The Company considers all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed, including carrybacks, tax planning strategies, reversal of deferred tax assets and liabilities and forecasted future taxable income. In making the determination related to uncertain tax positions, the Company considers the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of financial statement benefit. To the extent that an uncertain tax position or valuation allowance is established or increased or decreased during a period, the Company must include an expense or benefit within tax expense in the income statement. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

Derivative Instruments: The Company enters into derivative commodity instrument contracts primarily to mitigate exposure to commodity price risk associated with future sales of natural gas production.

The Company estimates the fair value of all derivative instruments using quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use market-based parameters as inputs, including forward curves, discount rates, volatilities and nonperformance risk. Nonperformance risk considers the effect of the Company's credit standing on the fair value of liabilities and the effect of the counterparty's credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company's or counterparty's credit rating and the yield of a risk-free instrument, and credit default swap rates where available. The values reported in the financial statements change as these estimates are revised to reflect actual results, or market conditions or other factors change, many of which are beyond the Company's control.

The Company believes that the accounting estimates related to derivative instruments are "critical accounting estimates" because the Company's financial condition and results of operations can be significantly impacted by changes in the market value of the Company's derivative instruments due to the volatility of natural gas prices, both NYMEX and basis. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

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Contingencies and Asset Retirement Obligations: The Company is involved in various regulatory and legal proceedings that arise in the ordinary course of business. The Company records a liability for contingencies based upon its assessment that a loss is probable and the amount of the loss can be reasonably estimated. The Company considers many factors in making these assessments, including history and specifics of each matter. Estimates are developed in consultation with legal counsel and are based upon an analysis of potential results.

The Company also accrues a liability for asset retirement obligations based on an estimate of the timing and amount of their settlement. For oil and gas wells, the fair value of the Company's plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are spud.

The Company believes that the accounting estimates related to contingencies and asset retirement obligations are "critical accounting estimates" because the Company must assess the probability of loss related to contingencies and the expected amount and timing of asset retirement obligations. In addition, the Company must determine the estimated present value of future liabilities. Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions.

Share-Based Compensation: The Company awards share-based compensation in connection with specific programs established under the 2009 and 2014 Long-Term Incentive Plans. Awards to employees are typically made in the form of performance-based awards, time-based restricted stock, time-based restricted units and stock options. Awards to directors are typically made in the form of phantom units that vest upon grant.

Restricted units and performance-based awards expected to be satisfied in cash are treated as liability awards. For liability awards, the Company is required to estimate, on the grant date and on each reporting date thereafter until vesting and payment, the fair value of the ultimate payout based upon the expected performance through, and value of the Company's common stock on, the vesting date. The Company then recognizes a proportionate amount of the expense for each period in the Company's financial statements over the vesting period of the award. The Company reviews its assumptions regarding performance and common stock value on a quarterly basis and adjusts its accrual when changes in these assumptions result in a material change in the fair value of the ultimate payouts.

Performance-based awards expected to be satisfied in Company common stock are treated as equity awards. For equity awards, the Company is required to determine the grant date fair value of the awards, which is then recognized as expense in the Company's financial statements over the vesting period of the award. Determination of the grant date fair value of the awards requires judgments and estimates regarding, among other things, the appropriate methodologies to follow in valuing the awards and the related inputs required by those valuation methodologies. Most often, the Company is required to obtain a valuation based upon assumptions regarding risk-free rates of return, dividend yields, expected volatilities and the expected term of the award. The risk-free rate is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the historical dividend yield of the Company's common stock adjusted for any expected changes and, where applicable, of the common stock of the peer group members at the time of grant. Expected volatilities are based on historical volatility of the Company's common stock and, where applicable, the common stock of the peer group members at the time of grant. The expected term represents the period of time elapsing during the applicable performance period.

For time-based restricted stock awards, the grant date fair value of the awards is recognized as expense in the Company's financial statements over the vesting period, historically three years. For director phantom units (which vest on the date of grant) expected to be satisfied in equity, the grant date fair value of the awards is recognized as an expense in the Company's financial statements in the year of grant. The grant date fair value, in both cases, is determined based upon the closing price of the Company's common stock on the date of the grant.

For non-qualified stock options, the grant date fair value is recognized as expense in the Company's financial statements over the vesting period, typically three years. The Company utilizes the Black-Scholes option pricing model to measure the fair value of stock options, which includes assumptions for a risk-free interest rate, dividend yield, volatility factor and expected term. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the time of grant. The dividend yield is based on the dividend yield of the Company's common stock at the time of grant. The expected volatility is based on historical volatility of the Company's common stock at the time of grant. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience at the time of grant.

The Company believes that the accounting estimates related to share-based compensation are "critical accounting estimates" because they may change from period to period based on changes in assumptions about factors affecting the ultimate payout of awards, including the number of awards to ultimately vest and the market price and volatility of the Company's common stock.

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Future results of operations for any particular quarterly or annual period could be materially affected by changes in the Company's assumptions. See Note 13 to the Consolidated Financial Statements for additional information regarding the Company's share-based compensation.

Business Combinations: Accounting for the acquisition of a business requires the identifiable assets and liabilities acquired to be recorded at fair value.

The most significant assumptions in a business combination include those used to estimate the fair value of the oil and gas properties acquired. The fair value of proved natural gas properties is determined using a risk-adjusted after-tax discounted cash flow analysis based upon significant assumptions including commodity prices; projections of estimated quantities of reserves; projections of future rates of production; timing and amount of future development and operating costs; projected reserve recovery factors; and a weighted average cost of capital.

The Company utilizes the guideline transaction method to estimate the fair value of unproved properties acquired in a business combination which requires the Company to use judgment in considering the value per undeveloped acre in recent comparable transactions to estimate the value of unproved properties.

The estimated fair value of midstream facilities and equipment, generally consisting of pipeline systems and compression stations, is estimated using the cost approach, which incorporates assumptions about the replacement costs for similar assets, the relative age of assets and any potential economic or functional obsolescence.

The fair values of the intangible assets are estimated using the multi-period excess earnings model which estimates revenues and cash flows derived from the intangible asset and then deducts portions of the cash flow that can be attributed to supporting assets otherwise recognized.

The Company believes that the accounting estimates related to business combinations are "critical accounting estimates" because the Company must, in determining the fair value of assets acquired, make assumptions about future commodity prices; projections of estimated quantities of reserves; projections of future rates of production; projections regarding the timing and amount of future development and operating costs; and projections of reserve recovery factors, per acre values of undeveloped property, replacement cost of and future cash flows from midstream assets, cash flow from customer relationships and non-compete agreements and the pre and post modification value of stock based awards. Different assumptions may result in materially different values for these assets which would impact the Company's financial position and future results of operations.

Goodwill: The Company believes that the accounting estimates related to goodwill are "critical accounting estimates" because the fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management's estimates of future financial results. The fair value estimation process requires considerable judgment and determining the fair value is sensitive to changes in assumptions impacting management's estimates of future financial results as well as other assumptions. The Company believes the estimates and assumptions used in estimating the fair value are reasonable and appropriate; however, different assumptions and estimates could materially impact the calculated fair value and the resulting determinations about goodwill impairment which could materially impact the Company's results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions. See Note 1 to the Consolidated Financial Statements for additional information regarding the Company's goodwill.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk and Derivative Instruments

The Company’s primary market risk exposure is the volatility of future prices for natural gas and NGLs. Due to the volatility of commodity prices, the Company is unable to predict future potential movements in the market prices for natural gas, and NGLs at the Company's ultimate sales points and thus cannot predict the ultimate impact of prices on its operations. Prolonged low, and/or significant or extended declines in, natural gas and NGLs prices could adversely affect, among other things, the Company’s development plans, which would decrease the pace of development and the level of the Company’s proved reserves.

The Company uses derivatives to reduce the effect of commodity price volatility. The Company's use of derivatives is further described in Notes 1 and 5 to the Consolidated Financial Statements and under the caption “Commodity Risk Management” in the "Capital Resources and Liquidity" section of Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The Company's OTC derivative commodity instruments are placed primarily with financial institutions and the creditworthiness of these institutions is regularly monitored. The Company primarily enters into derivative instruments to hedge forecasted sales of production. The Company also enters into derivative instruments to hedge basis and exposure to

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fluctuations in interest rates. The Company's use of derivative instruments is implemented under a set of policies approved by the Company's Hedge and Financial Risk Committee and reviewed by the Audit Committee of the Company's Board of Directors.

For the derivative commodity instruments used to hedge the Company's forecasted sales of production, most of which are hedged at NYMEX natural gas prices, the Company sets policy limits relative to the expected production and sales levels which are exposed to price risk. The Company has an insignificant amount of financial natural gas derivative commodity instruments for trading purposes.

The derivative commodity instruments currently utilized by the Company are primarily fixed price swap agreements, collar agreements and option agreements which may require payments to or receipt of payments from counterparties based on the differential between two prices for the commodity. The Company may also use other contractual agreements in implementing its commodity hedging strategy.

The Company monitors price and production levels on a continuous basis and makes adjustments to quantities hedged as warranted. The Company's overall objective in its hedging program is to protect a portion of cash flows from undue exposure to the risk of changing commodity prices.

For information on the quantity of derivative commodity instruments held by the Company, see Note 5 to the Consolidated Financial Statements and the "Commodity Risk Management" section in the "Capital Resources and Liquidity" section of Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations".

A hypothetical decrease of 10% in the market price of natural gas from the December 31, 2018 and 2017 levels would have increased the fair value of these natural gas derivative instruments by approximately $432.5 million and $386.2 million, respectively. A hypothetical increase of 10% in the market price of natural gas from the December 31, 2018 and 2017 levels would have decreased the fair value of these natural gas derivative instruments by approximately $443.4 million and $384.9 million, respectively. The Company determined the change in the fair value of the derivative commodity instruments using a method similar to its normal determination of fair value as described in Note 1 to the Consolidated Financial Statements. The Company assumed a 10% change in the price of natural gas from its levels at December 31, 2018 and December 31, 2017. The price change was then applied to these natural gas derivative commodity instruments recorded on the Company's Consolidated Balance Sheets, resulting in the hypothetical change in fair value.

The above analysis of the derivative commodity instruments held by the Company does not include the offsetting impact that the same hypothetical price movement may have on the Company's physical sales of natural gas. The portfolio of derivative commodity instruments held to hedge the Company's forecasted produced gas approximates a portion of the Company's expected physical sales of natural gas. Therefore, an adverse impact to the fair value of the portfolio of derivative commodity instruments held to hedge the Company's forecasted production associated with the hypothetical changes in commodity prices referenced above should be offset by a favorable impact on the Company's physical sales of natural gas, assuming the derivative commodity instruments are not closed out in advance of their expected term, and the derivative commodity instruments continue to function effectively as hedges of the underlying risk.

If the underlying physical transactions or positions are liquidated prior to the maturity of the derivative commodity instruments, a loss on the financial instruments may occur or the derivative commodity instruments might be worthless as determined by the prevailing market value on their termination or maturity date, whichever comes first.

Interest Rate Risk

Changes in interest rates affect the amount of interest the Company earns on cash, cash equivalents and short-term investments and the interest rate the Company pays on borrowings under its revolving credit facility and the Company's Floating Rate Notes. All of the Company’s Senior Notes, other than the Floating Rate Notes, are fixed rate and thus do not expose the Company to fluctuations in its results of operations or liquidity from changes in market interest rates. Changes in interest rates do affect the fair value of the Company’s fixed rate debt. See Note 10 to the Consolidated Financial Statements for further discussion of the Company’s borrowings, as applicable, and Note 6 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value of long-term debt.

Other Market Risks

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company’s OTC derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those

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companies individually as well as the financial industry as a whole. The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include closely monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

Approximately 64%, or $369.5 million, of the Company's OTC derivative contracts outstanding at December 31, 2018 had a positive fair value. Approximately 63%, or $242.0 million, of the Company's OTC derivative contracts outstanding at December 31, 2017 had a positive fair value.

As of December 31, 2018, the Company was not in default under any derivative contracts and had no knowledge of default by any counterparty to its derivative contracts. The Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company's established fair value procedure. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

The Company is also exposed to the risk of nonperformance by credit customers on physical sales of natural gas, NGLs and oil. A significant amount of revenues and related accounts receivable are generated from the sale of produced natural gas and NGLs to certain marketers, utility and industrial customers located in the Appalachian Basin and in markets available through the Company's current transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States as well as Canada. The Company also contracts with certain processors to market a portion of NGLs on behalf of the Company.

No one lender of the large group of financial institutions in the syndicate for the EQT credit facility holds more than 10% of the respective facility. The large syndicate group and relatively low percentage of participation by each lender are expected to limit the Company's exposure to disruption or consolidation in the banking industry.

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Item 8. Financial Statements and Supplementary Data

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Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of EQT Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of EQT Corporation and subsidiaries (the Company) as of December 31, 2018 and 2017, the related statements of consolidated operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2018, and the related notes and the financial statement schedule listed in the Index at Item 15 (a) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2018 and 2017, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 14, 2019 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 1950.

Pittsburgh, Pennsylvania
February 14, 2019

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Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of EQT Corporation

Opinion on Internal Control over Financial Reporting

We have audited EQT Corporation and subsidiaries' internal control over financial reporting as of December 31, 2018, 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, EQT Corporation and subsidiaries (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, 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 the Company as of December 31, 2018 and 2017, and the related statements of consolidated operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2018 and the related notes and the financial statement schedule listed in the Index at Item 15 (a) of the Company and our report dated February 14, 2019 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 on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We 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
Pittsburgh, Pennsylvania
February 14, 2019

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED OPERATIONS
YEARS ENDED DECEMBER 31,

	2018	2017	2016
	(Thousands except per share amounts)		
Operating revenues:			
Sales of natural gas, oil and NGLs	$4,695,519	$2,651,318	$1,594,997
Net marketing services and other	40,940	49,681	41,048
(Loss) gain on derivatives not designated as hedges	(178,591)	390,021	(248,991)
Total operating revenues	4,557,868	3,091,020	1,387,054
Operating expenses:			
Transportation and processing	1,697,001	1,164,783	880,191
Production	195,775	181,349	174,170
Exploration	6,765	17,565	4,663
Selling, general and administrative	284,220	208,986	218,946
Depreciation and depletion	1,569,038	970,985	856,451
Impairment/loss on sale of long-lived assets	2,709,976	—	—
Impairment of goodwill	530,811	—	—
Lease impairments and expirations	279,708	7,552	15,686
Transaction costs	26,331	152,188	—
Amortization of intangible assets	41,367	5,400	—
Total operating expenses	7,340,992	2,708,808	2,150,107
Gain on sale of assets	—	—	8,025
Operating (loss) income	(2,783,124)	382,212	(755,028)
Other expense	65,349	2,987	8,075
Loss on debt extinguishment	—	12,641	—
Interest expense	228,958	167,971	131,159
(Loss) income from continuing operations before income taxes	(3,077,431)	198,613	(894,262)
Income tax (benefit)	(696,511)	(1,188,416)	(362,769)
(Loss) income from continuing operations	(2,380,920)	1,387,029	(531,493)
Income from discontinued operations, net of tax (see Note 2)	373,762	471,113	400,430
Net (loss) income	(2,007,158)	1,858,142	(131,063)
Less: Net income from discontinued operations attributable to noncontrolling interests	237,410	349,613	321,920
Net (loss) income attributable to EQT Corporation	$(2,244,568)	$1,508,529	$(452,983)
Amounts attributable to EQT Corporation:			
(Loss) income from continuing operations	$(2,380,920)	$1,387,029	$(531,493)
Income from discontinued operations, net of tax	136,352	121,500	78,510
Net (loss) income attributable to EQT Corporation	$(2,244,568)	$1,508,529	$(452,983)
Earnings per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	260,932	187,380	166,978
(Loss) income from continuing operations	$(9.12)	$7.40	$(3.18)
Income from discontinued operations	0.52	0.65	0.47

Net (loss) income	$(8.60)	$8.05	$(2.71)
Diluted:			
Weighted average common stock outstanding	260,932	187,727	166,978
(Loss) income from continuing operations	$(9.12)	$7.39	$(3.18)
Income from discontinued operations	0.52	0.65	0.47
Net (loss) income	$(8.60)	$8.04	$(2.71)

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
YEARS ENDED DECEMBER 31,

	2018	2017	2016
	(Thousands)		
Net (loss) income	$(2,007,158)	$1,858,142	$(131,063)
Other comprehensive loss, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax expense (benefit) of $2,584, ($3,191) and ($36,296)	(4,625)	(4,982)	(55,155)
Interest rate, net of tax expense of $80, $105 and $104	168	144	144
Pension and other post-retirement benefits liability adjustment, net of tax expense of $510, $193 and $6,778	606	338	10,675
Other comprehensive (loss)	(3,851)	(4,500)	(44,336)
Comprehensive (loss) income	(2,011,009)	1,853,642	(175,399)
Less: Comprehensive income from discontinued operations attributable to noncontrolling interests	237,410	349,613	321,920
Comprehensive (loss) income attributable to EQT Corporation	$(2,248,419)	$1,504,029	$(497,319)

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS
YEARS ENDED DECEMBER 31,

	2018	2017	2016
	(Thousands)		
Cash flows from operating activities:			
Net (loss) income	$(2,007,158)	$1,858,142	$(131,063)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Deferred income taxes (benefit)	(510,405)	(1,050,612)	(180,261)
Depreciation and depletion	1,729,739	1,077,559	927,920
Amortization of intangibles assets	77,374	10,940	—
Amortization of financing costs and accretion expense	17,914	—	—
Asset and lease impairments and exploratory well costs	2,989,684	20,327	75,434
Goodwill impairment	798,689	—	—
Gain on sale of assets	—	—	(8,025)
Loss on debt extinguishment	—	12,641	—
Provision for (recoveries of) losses on accounts receivable	3,078	(979)	3,856
Non-cash other expense (income)	18,335	(24,955)	(31,693)
Share-based compensation expense	25,189	94,592	44,605
Loss (gain) on derivatives not designated as hedges	178,591	(390,021)	248,991
Cash settlements (paid) received on derivatives not designated as hedges	(225,279)	40,728	279,425
Pension settlement charge	—	—	9,403
Changes in other assets and liabilities:			
Accounts receivable	(439,062)	(8,979)	(165,507)
Accounts payable	457,113	(16,680)	40,548
Tax receivable	(117,188)	(12,285)	34,880
Other items, net	(20,358)	27,280	(84,193)
Net cash provided by operating activities	2,976,256	1,637,698	1,064,320
Cash flows from investing activities:			
Capital expenditures	(2,964,924)	(1,549,351)	(942,810)
Cash payments for Rice Merger (as defined in Note 3), net of cash acquired	—	(1,560,272)	—
Capital expenditures for other acquisitions	(34,113)	(828,657)	(1,061,735)
Capital expenditures from discontinued operations	(732,727)	(380,151)	(584,819)
Net sales of (investments in) trading securities	—	283,758	(284,882)
Proceeds from sale of assets	583,381	3,573	75,000
Exploratory dry hole costs	—	(11,420)	(1,369)
Capital contributions to Mountain Valley Pipeline, LLC, net of sales of interest (Note 2)	(820,943)	(159,550)	(85,866)
Other investing activities	(9,778)	—	—
Net cash used in investing activities	(3,979,104)	(4,202,070)	(2,886,481)
Cash flows from financing activities:			
Net proceeds from the issuance of common shares of EQT Corporation	—	—	1,225,999
Net proceeds from the issuance of common units of EQM Midstream Partners, LP	—	—	217,102
Proceeds from issuance of debt	2,500,000	3,000,000	500,000
Increase in borrowings on credit facilities	8,637,500	2,063,000	740,000
Repayment of borrowings on credit facilities	(8,953,500)	(1,076,500)	(1,039,000)
Dividends paid	(31,375)	(20,827)	(20,156)

Distributions to noncontrolling interests	(380,651)	(236,123)	(189,981)
Net cash transferred at Separation and Distribution (Note 2)	(129,008)	—	—
Contribution to Strike Force Midstream LLC by minority owner, net of distribution	—	6,738	—
Acquisition of 25% of Strike Force Midstream LLC	(175,000)	—	—
Repayments and retirements of debt	(8,376)	(2,000,000)	(5,119)
Proceeds and excess tax benefits from awards under employee compensation plans	1,946	244	6,165
Cash paid for taxes related to net settlement of share-based incentive awards	(22,647)	(72,116)	(26,931)
Debt issuance costs and revolving credit facility origination fees	(40,966)	(41,876)	(8,580)
Premiums paid on debt extinguishment	—	(89,363)	—
Repurchase and retirement of common stock	(538,876)	—	—
Repurchase of common stock	(27)	(30)	(30)
Net cash provided by financing activities	859,020	1,533,147	1,399,469
Net change in cash and cash equivalents	(143,828)	(1,031,225)	(422,692)
Cash, cash equivalents and restricted cash at beginning of year	147,315	1,178,540	1,601,232
Cash, cash equivalents and restricted cash at end of year	$3,487	$147,315	$1,178,540
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$260,959	$189,371	$144,657
Income taxes, net	$(3,675)	$3,637	$(41,142)

See notes to consolidated financial statements. See Note 1 for supplemental cash flow information.

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2018	2017
	(Thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$3,487	$26,311
Accounts receivable (less accumulated provision for doubtful accounts: $8,648 in 2018; $7,780 in 2017)	1,241,843	664,685
Derivative instruments, at fair value	481,654	241,952
Tax receivable	131,573	14,385
Prepaid expenses and other	111,107	59,462
Current assets of discontinued operations	—	156,260
Total current assets	1,969,664	1,163,055
Property, plant and equipment	22,148,012	25,396,026
Less: accumulated depreciation and depletion	4,755,505	5,666,018
Net property, plant and equipment	17,392,507	19,730,008
Intangible assets, net	77,333	118,700
Goodwill	—	470,849
Investment in Equitrans Midstream Corporation	1,013,002	—
Other assets	268,838	250,734
Noncurrent assets of discontinued operations	—	7,789,258
Total assets	$20,721,344	$29,522,604

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EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2018	2017
	(Thousands)	
Liabilities and Shareholders' Equity		
Current liabilities:		
Current portion of debt	$704,390	$12,406
Accounts payable	1,059,873	726,433
Derivative instruments, at fair value	336,051	139,089
Other current liabilities	254,687	274,276
Current liabilities of discontinued operations	—	80,033
Total current liabilities	2,355,001	1,232,237
Credit facility borrowings	800,000	1,295,000
Senior Notes	3,882,932	4,575,203
Notes payable to EQM Midstream Partners, LP	110,059	114,720
Deferred income taxes	1,823,381	1,889,962
Other liabilities and credits	791,742	752,837
Noncurrent liabilities of discontinued operations	—	1,248,032
Total liabilities	9,763,115	11,107,991
Shareholders' Equity:		
Common stock, no par value, authorized 320,000 shares, shares issued: 257,225 in 2018 and 267,871 in 2017	7,828,554	9,388,903
Treasury stock, shares at cost: 2,753 in 2018 (no shares held in rabbi trust) and 3,551 in 2017 (including 253 held in rabbi trust)	(49,194)	(63,602)
Retained earnings	3,184,275	3,996,775
Accumulated other comprehensive loss	(5,406)	(2,458)
Total common shareholders' equity	10,958,229	13,319,618
Noncontrolling interests in discontinued operations	—	5,094,995
Total shareholder's equity	10,958,229	18,414,613
Total liabilities and shareholders' equity	$20,721,344	$29,522,604

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2018, 2017 and 2016

	Common Stock					
	Shares Outstanding	No Par Value	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests in Discontinued Operations	Total Shareholders' Equity
			(Thousands)			
Balance, December 31, 2015	152,554	$2,049,201	$2,982,212	$ 46,378	$ 2,950,251	$8,028,042
Comprehensive income (net of tax):						
Net (loss) income			(452,983)		321,920	(131,063)
Net change in cash flow hedges:						
Natural gas, net of tax of ($36,296)				(55,155)		(55,155)
Interest rate, net of tax of $104				144		144
Pension and other post retirement benefits liability adjustment, net of tax of $6,778				10,675		10,675
Dividends ($0.12 per share)			(20,156)			(20,156)
Share-based compensation plans, net	724	42,782			161	42,943
Distributions to noncontrolling interests in discontinued operations ($3.05 and $0.571 per common unit for EQM Midstream Partners, LP and EQGP Holdings, LP, respectively)					(189,981)	(189,981)
Issuance of common shares of EQT Corporation	19,550	1,225,999			—	1,225,999
Issuance of common units of EQM Midstream Partners, LP					217,102	217,102
Elimination of deferred taxes		5,921				5,921
Changes in ownership of consolidated subsidiaries		25,293			(40,487)	(15,194)
Repurchase and retirement of common stock	(1)	(30)				(30)
Balance, December 31, 2016	172,827	$3,349,166	$2,509,073	$ 2,042	$ 3,258,966	$9,119,247
Comprehensive income (net of tax):						
Net income			1,508,529		349,613	1,858,142
Net change in cash flow hedges:						
Natural gas, net of tax of ($3,191)				(4,982)		(4,982)
Interest rate, net of tax of $105				144		144
Pension and other post retirement benefits liability adjustment, net of tax of $193				338		338
Dividends ($0.12 per share)			(20,827)			(20,827)
Share-based compensation plans, net	580	26,436			190	26,626

Distributions to noncontrolling interests in discontinued operations ($3.655 and $0.806 per common unit for EQM Midstream Partners, LP and EQGP Holdings, LP, respectively)					(236,123)	(236,123)
Rice Merger, net of withholdings	90,914	5,949,729			1,715,611	7,665,340
Contribution from noncontrolling interest, net of distribution					6,738	6,738
Repurchase of common stock	(1)	(30)				(30)
Balance, December 31, 2017	264,320	$9,325,301	$3,996,775	$ (2,458)	$ 5,094,995	$ 18,414,613
Comprehensive income (net of tax):						
Net (loss) income			(2,244,568)		237,410	(2,007,158)
Net change in cash flow hedges:						
Natural gas, net of tax of $2,584				(4,625)		(4,625)
Interest rate, net of tax of $80				168		168
Other post retirement benefits liability adjustment, net of tax of $510				606		606
Dividends ($0.12 per share)			(31,375)			(31,375)
Share-based compensation plans, net	798	7,432			953	8,385
Distributions to noncontrolling interests in discontinued operations ($4.295, $1.123 and $0.5966 per common unit for EQM Midstream Partners, LP, EQGP Holdings, LP and RM Partners LP (formerly known as Rice Midstream Partners LP), respectively)					(380,651)	(380,651)
Change in accounting principle (a)			4,113			4,113
Repurchase and retirement of common stock	(10,646)	(538,876)				(538,876)
Purchase of Strike Force Midstream LLC noncontrolling interests		1,818			(176,818)	(175,000)
Changes in ownership of consolidated subsidiaries		(158,560)			214,930	56,370
Distribution of Equitrans Midstream Corporation		(857,755)	1,459,330	903	(4,990,819)	(4,388,341)
Balance, December 31, 2018	254,472	$7,779,360	$3,184,275	$ (5,406)	$ —	$ 10,958,229

(a) Related to adoption of ASU No. 2016-01. See Note 1 for additional information.

Common shares authorized: 320,000 shares. Preferred shares authorized: 3,000 shares. There are no preferred shares issued or outstanding.

See notes to consolidated financial statements.

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EQT CORPORATION AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2018

1. Summary of Significant Accounting Policies

Principles of Consolidation: The Consolidated Financial Statements include the accounts of EQT Corporation and all subsidiaries, ventures and partnerships in which a controlling interest is held (EQT or the Company). All significant intercompany accounts and transactions have been eliminated in consolidation.

Segments: The Company's operations consist of one reportable segment. The Company has a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. The Company measures financial performance as a single enterprise and not on an area-by-area basis.

Substantially all of the Company's operating revenues, income from operations and assets are generated or located in the United States.

Use of Estimates: The preparation of financial statements in conformity with United States generally accepted accounting principles (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and accompanying notes. Actual results could differ from those estimates.

Cash Equivalents: The Company considers all highly liquid investments with an original maturity of three months or less when purchased to be cash equivalents. These investments are accounted for at cost. Interest earned on cash equivalents is included as a reduction of interest expense.

Trading Securities: Trading securities consist of liquid debt securities that are carried at fair value. Realized losses of $2.6 million and unrealized gains of $1.5 million on these debt securities are included in other income in the Statements of Consolidated Operations for the years ended December 31, 2017 and 2016, respectively. The Company initiated its investments in trading securities in 2016 to enhance returns on a portion of its significant cash balance at that time. Investments within the Company's portfolio are subject to a minimum credit rating based on type of investment, and the portfolio's asset mix is subject to exposure limits to ensure issuer and asset class diversification. As of March 31, 2017, the Company closed its positions on all trading securities.

Accounts Receivable: Accounts receivable primarily relate to the sales of natural gas, oil and natural gas liquids (NGLs) and amounts due from joint interest partners. Amounts due from contracts with customers were $783.0 million at December 31, 2018. Joint interest receivables were $324.2 million and $149.3 million at December 31, 2018 and 2017, respectively.

Inventories: Generally, the Company's inventory balance consists of natural gas stored underground or in pipelines and materials and supplies recorded at the lower of average cost or market. During the years ended December 31, 2018, 2017 and 2016, the Company recorded no lower of cost or market adjustments related to inventory.

Investment in Equitrans Midstream Corporation: The Company owns approximately 19.9% of the outstanding shares of common stock of Equitrans Midstream Corporation (Equitrans Midstream). The Company does not have the ability to exercise significant influence and does not have a controlling financial interest in Equitrans Midstream or any of its subsidiaries. As such, this investment is accounted for as an investment in an equity security that is recorded at fair value in the Consolidated Balance Sheets. See Note 2 and 6.

Property, Plant and Equipment: The Company's property, plant and equipment consist of the following:

	As of December 31,	
	2018	2017
	(Thousands)	
Oil and gas producing properties, successful efforts method	$21,814,779	$23,937,154
Accumulated depreciation and depletion	(4,666,212)	(5,121,646)
Net oil and gas producing properties	17,148,567	18,815,508
Other properties, at cost less accumulated depreciation	243,940	914,500
Net property, plant and equipment	$17,392,507	$19,730,008

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The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, the cost of productive wells and related equipment, development dry holes, as well as productive acreage, including productive mineral interests, are capitalized and depleted using the unit-of-production method. These capitalized costs include salaries, benefits and other internal costs directly attributable to these activities. The Company capitalized internal costs of $130.0 million, $114.6 million and $115.4 million in 2018, 2017 and 2016, respectively, for production related activities. The Company also capitalized $29.0 million, $20.5 million and $19.2 million of interest expense related to Marcellus, Upper Devonian and Utica well development in 2018, 2017 and 2016, respectively. Depletion expense is calculated based on the actual produced sales volumes multiplied by the applicable depletion rate per unit. The depletion rates are derived by dividing the net capitalized costs by the number of units expected to be produced over the life of the reserves for lease costs and well costs separately. Costs of exploratory dry holes, exploratory geological and geophysical activities, delay rentals and other property carrying costs are charged to expense. The majority of the Company’s producing oil and gas properties were depleted at an overall average rate of $1.04 per Mcfe, $1.04 per Mcfe and $1.06 per Mcfe for the years ended December 31, 2018, 2017 and 2016, respectively.

The carrying values of the Company’s proved oil and gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. In order to determine whether impairment has occurred, the Company estimates the expected future cash flows (on an undiscounted basis) from its oil and gas properties and compares these estimates to the carrying values of the properties. The estimated future cash flows used to test those properties for recoverability are based on proved and, if determined reasonable by management, risk-adjusted probable reserves, utilizing assumptions generally consistent with the assumptions utilized by the Company's management for internal planning and budgeting purposes, including, among other things, the intended use of the asset, anticipated production from reserves, future market prices for natural gas, NGLs and oil, adjusted accordingly for basis differentials, future operating costs and inflation. Proved oil and gas properties that have carrying amounts in excess of estimated future undiscounted cash flows are written down to fair value, which is estimated by discounting the estimated future cash flows using discount rate and other assumptions that marketplace participants would use in their estimates of fair value.

During 2018, there were indicators that the carrying values of certain of the Company’s oil and gas producing properties may be impaired due to management's intent to divest the Company's Huron and Permian assets prior to the end of their useful lives. As a result of the impairment evaluation during 2018, the Company recorded an impairment of $2.4 billion associated with the production and related midstream assets in the Huron and Permian plays that were divested during the year (collectively, the 2018 Divestitures). There were no indicators of impairment identified during 2017. During 2016, there were indicators that the carrying value of the Huron assets may be impaired due to declines in commodity prices. As a result of the impairment indicators as of December 31, 2016, the Company performed an undiscounted cash flow analysis and determined that no impairment existed during 2016.

The Company impaired all of its goodwill in the fourth quarter 2018. This resulted in an impairment indicator for certain other long-lived assets including proved oil and gas properties and intangible assets. The Company performed an undiscounted cash flow analysis and determined that no additional impairment existed.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. The likelihood of an impairment of unproved oil and gas properties increases as the expiration of a lease term approaches if drilling activity has not commenced. If it is determined that the Company does not intend to drill on the property prior to expiration or does not have the intent and ability to extend, renew, trade, or sell the lease prior to expiration, an impairment expense is recorded. Expense for lease expirations that were not previously impaired are recorded as the leases expire. For the years ended

December 31, 2018, 2017 and 2016, the Company recorded $279.7 million, $7.6 million and $15.7 million, respectively for lease impairments and expirations. The Company’s unproved properties had a net book value of $4,166.0 million and $5,016.3 million at December 31, 2018 and 2017, respectively.

During 2017, the Company drilled one exploratory dry hole within its non-core acreage and the related expenditures have been included within exploration expense in the Statements of Consolidated Operations for the year ended December 31, 2017. There were no exploratory wells drilled during 2018 and there were no capitalized exploratory wells costs at December 31, 2018 and 2017.

Goodwill: Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of the acquired business. At November 30, 2018, prior to the completion of the annual goodwill impairment test, the goodwill balance totaled $530.8 million. Goodwill is tested for impairment at the Company's single reporting unit level on an annual basis and between annual tests if events or circumstances indicate it is more likely than not that the fair value of a reporting unit is below its carrying value. The Company considered market capitalization and other valuation techniques, as applicable, when estimating fair value for goodwill

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impairment testing purposes. In connection with the annual goodwill impairment testing for 2018, the Company identified several qualitative factors that are considered in assessing goodwill for impairment. These factors included the steep decline in the Company's stock price through the quarter ended December 31, 2018, the weak market performance of the Company's peers for the same period, exceeding the Company's capital budget as announced in October 2018, recent operational volume curtailments and the Company's new strategy to slow the cadence of its future drilling operations to generate near-term free cash flow.

The Company conducted the first step of the goodwill impairment test for the single reporting unit as of November 30, 2018. The Company utilized its market capitalization plus a control premium approach to estimate the fair value of the Company (and in turn the single reporting unit). The estimated market capitalization was determined by multiplying the 30 day weighted average stock price and the Company's common shares outstanding as of November 30, 2018. Based on the analysis utilizing the market capitalization plus control premium approach, the estimated fair value of the reporting unit was significantly less than its carrying value. As the Company adopted ASU No. 2017-04 (ASU 2017-04), Simplifying the Test of Goodwill Impairment, all of the goodwill was impaired. This impairment charge was classified as a component of operating expenses.

Intangible Assets: These intangible assets were initially recorded under the acquisition method of accounting at their estimated fair values at the Rice Merger (defined in Note 3) acquisition date. The Company’s intangible assets are composed of non-compete agreements with former Rice Energy Inc. executives. The non-compete agreements have a useful life of 3 years. The Company calculates amortization of intangible assets using the straight-line method over the estimated useful life of the intangible assets. Amortization expense recorded in the Statements of Consolidated Operations as of December 31, 2018 and 2017 was $41.4 million and $5.4 million. The estimated annual amortization expense over the remaining two years is as follows: 2019 $41.4 million and 2020 $35.9 million.

Intangible assets, net as of December 31, 2018 and 2017 are detailed below.

	December 31,	
	2018	2017
	(Thousands)	
Non-compete agreements	$124,100	$124,100
Less: accumulated amortization	(46,767)	(5,400)
Intangible assets, net	$77,333	$118,700

Sales and Retirements Policies: No gain or loss is recognized on the partial sale of proved developed oil and gas reserves unless non-recognition would significantly alter the relationship between capitalized costs and remaining proved reserves for the affected amortization base. When gain or loss is not recognized, the amortization base is reduced by the amount of the proceeds.

Derivative Instruments: Derivatives are held as part of a formally documented risk management program. The Company’s use of derivative instruments is implemented under a set of policies approved by the Company’s Hedge and Financial Risk Committee (HFRC) and reviewed by the Audit Committee of the Company's Board of Directors. The HFRC is composed of the president and chief executive officer, the chief financial officer and other officers of the Company.

In regards to commodity price risk, the financial instruments currently utilized by the Company are primarily fixed price swap agreements, collar agreements and option agreements. The Company engages in basis swaps to protect earnings from undue exposure to the risk of geographic disparities in commodity prices and may engage in interest rate swaps to hedge exposure to interest rate fluctuations on potential debt issuances. The Company also uses a limited number of other contractual agreements in implementing its commodity hedging strategy. The Company has an insignificant number of natural gas derivative instruments for trading purposes.

Any changes in fair value of derivative instruments are recognized net within operating revenues in the Statements of Consolidated Operations.

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Other Current Liabilities: Other current liabilities as of December 31, 2018 and 2017 are detailed below.

	December 31,	
	2018	2017
	(Thousands)	
Incentive compensation	$46,937	$72,910
Taxes other than income	75,978	62,091
Accrued interest payable	42,998	41,926
Legal reserve	53,500	—
Severance accrual	8,893	41,474
All other accrued liabilities	26,381	55,875
Total other current liabilities	$254,687	$274,276

Revenue Recognition: For information on revenue recognition from contracts with customers and gains and losses on derivative commodity instruments, see Note 4 and Note 5, respectively.

Unamortized Debt Discount and Issuance Expense: Discounts and expenses incurred with the issuance of debt are amortized over the term of the debt. These amounts are presented as a reduction of Senior Notes on the accompanying Consolidated Balance Sheets. See Note 10.

Transportation and Processing: Costs incurred to gather, process and transport gas produced by the Company to market sales points are recorded as transportation and processing costs in the Statements of Consolidated Operations. The Company markets some transportation for resale. These costs, which are not incurred to transport gas produced by the Company, are reflected as a deduction from net marketing services and other revenues.

Income Taxes: The Company files a consolidated federal income tax return and utilizes the asset and liability method to account for income taxes. The provision for income taxes represents amounts paid or estimated to be payable, net of amounts refunded or estimated to be refunded, for the current year and the change in deferred taxes, exclusive of amounts recorded in Other Comprehensive Income (OCI). Any refinements to prior years' taxes made due to subsequent information are reflected as adjustments in the current period. Separate income taxes are calculated for income from continuing operations, income from discontinued operations and items charged or credited directly to shareholders' equity.

Deferred income tax assets and liabilities are determined based on temporary differences between the financial reporting and tax bases of assets and liabilities and are recognized using enacted tax rates for the effect of such temporary differences. Deferred tax assets are reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized.

In accounting for uncertainty in income taxes of a tax position taken or expected to be taken in a tax return, the Company utilizes a recognition threshold and measurement attribute for the financial statement recognition and measurement. The recognition threshold requires the Company to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position in order to record any financial statement benefit. If it is more likely than not that a tax position will be sustained, then the Company must measure the tax position to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income tax expense.

Provision for Doubtful Accounts: Judgment is required to assess the ultimate realization of the Company's accounts receivable, including assessing the probability of collection and the creditworthiness of certain customers. Reserves for uncollectible accounts are recorded as part of selling, general and administrative expense in the Statements of Consolidated Operations. The reserves are based on historical experience, current and expected economic trends and specific information about customer accounts.

Earnings Per Share (EPS): Basic EPS are computed by dividing net income attributable to EQT by the weighted average number of common shares outstanding during the period, without considering any dilutive items. Diluted EPS are computed by dividing net income attributable to EQT by the weighted average number of common shares and potentially dilutive securities, net of shares assumed to be repurchased using the treasury stock method. Purchases of treasury shares are calculated using the

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average share price for the Company's common stock during the period. Potentially dilutive securities arise from the assumed conversion of outstanding stock options and other share-based awards.

In periods when the Company reports a net loss, all options and restricted stock are excluded from the calculation of diluted weighted average shares outstanding because of their anti-dilutive effect on loss per share. As a result, all options and all restricted stock were excluded from the calculation of diluted EPS for the years ended December 31, 2018 and 2016. Potentially dilutive securities (options and restricted stock awards) included in the calculation of diluted EPS totaled 346,528 shares for the year ended December 31, 2017. Options to purchase common stock excluded from potentially dilutive securities because they were anti-dilutive totaled 429,785 shares for the year ended December 31, 2017.

Asset Retirement Obligations: The Company accrues a liability for legal asset retirement obligations based on an estimate of the timing and amount of settlement. For oil and gas wells, the fair value of the Company's plugging and abandonment obligations is required to be recorded at the time the obligations are incurred, which is typically at the time the wells are spud. Upon initial recognition of an asset retirement obligation, the Company increases the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to depreciation and depletion, and the initial capitalized costs are depleted over the useful lives of the related assets.

The Company's asset retirement obligations related to the abandonment of oil and gas producing facilities include reclaiming drilling sites, plugging wells and dismantling related structures. Estimates are based on historical experience in plugging and abandoning wells and reclaiming or disposing of other assets as well as the estimated remaining lives of the wells and assets.

The following table presents a reconciliation of the beginning and ending carrying amounts of the Company's asset retirement obligations which are included in other liabilities and credits in the Consolidated Balance Sheets. The Company does not have any assets that are legally restricted for purposes of settling these obligations.

	December 31,	
	2018	2017
	(Thousands)	
Asset retirement obligation as of beginning of period	$443,349	$243,600
Accretion expense	17,513	13,644
Liabilities incurred	7,785	19,678
Liabilities settled	(3,722)	(3,750)
Liabilities assumed in the Rice Merger	27,999	41,655
Liabilities removed due to divestitures	(231,936)	(88)
Change in estimates	26,817	128,610
Asset retirement obligation as of end of period	$287,805	$443,349

During 2018 and 2017, the Company had changes in estimates for the plugging of conventional and horizontal wells, primarily related to increased cost assumptions of complying with existing regulatory requirements which were derived, in part, based on recent plugging experience and actual costs incurred. The Company operates in several states that have implemented enhanced requirements that resulted in the use of additional materials during the plugging process which has increased the estimated cost to plug these wells over recent years.

Self-Insurance: The Company is self-insured for certain losses related to workers' compensation and maintains a self-insured retention for general liability, automobile liability, environmental liability and other casualty coverage. The Company maintains stop loss coverage with third-party insurers to limit the total exposure for general liability, automobile liability, environmental liability and workers' compensation. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are based on analyses of historical data and actuarial estimates and are not discounted. The liabilities are reviewed by management quarterly and by independent actuaries annually to ensure that they are appropriate. While the Company believes these estimates are reasonable based on the information available, financial results could be impacted if actual trends, including the severity or frequency of claims, differ from estimates.

Pension and Other Post-Retirement Benefit Plans: The Company, as sponsor of the EQT Corporation Retirement Plan for Employees (Retirement Plan), a defined benefit pension plan, terminated the Retirement Plan effective December 31, 2014. On March 2, 2016, the Internal Revenue Service (IRS) issued a favorable determination letter for the termination of the Retirement Plan. On June 28, 2016, the Company purchased annuities from, and transferred the Retirement Plan assets and liabilities to, American General Life Insurance Company. As a result, during 2016, the Company reclassified the actuarial losses remaining in accumulated other comprehensive loss of approximately $9.4 million to earnings. In connection with the purchase of annuities, the Company made a cash payment of approximately $5.4 million to fully fund the Retirement Plan upon liquidation during the second quarter of 2016.

Currently, the Company recognizes expense for on-going post-retirement benefits other than pensions. Expense recognized by the Company related to its defined contribution plan totaled $17.3 million in 2018, $16.6 million in 2017 and $16.0 million in 2016.

Discontinued Operations: For businesses classified as discontinued operations, the balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities of discontinued operations on the Consolidated Balance Sheet and to discontinued operations on the Statement of Consolidated Operations for all periods presented. The Statement of Consolidated Cash Flows is not required to be reclassified for discontinued operations for any period. See Note 2.

Supplemental Cash Flow Information: Non-cash investing activities for the year ended December 31, 2018 included $34.6 million for asset retirement cost additions, $(274.2) million for changes in accruals of property, plant and equipment, $14.4 million for measurement period adjustments for 2017 acquisitions, $4.3 million in capitalized non-cash share-based compensation and $176.6 million for the increase in the capital contributions payable to Mountain Valley Pipeline, LLC. Non-cash investing activities for the year ended December 31, 2017 included $143.6 million for asset retirement cost additions, $4.4 million for changes in accruals of property, plant and equipment, $10.0 million of net liabilities assumed in 2017 acquisitions, $(14.3) million for measurement period adjustments for 2016 acquisitions, $9.0 million in capitalized non-cash stock based compensation and $94.3 million for the increase in the capital contributions payable to Mountain Valley Pipeline, LLC. See discussion of equity issued in consideration for the Rice Merger in Note 3. Non-cash investing activities for the year ended December 31, 2016 included $87.6 million of net liabilities assumed in acquisitions, $(27.7) million for changes in accruals of property, plant and equipment, $66.2 million for asset retirement cost additions, $16.6 million in capitalized non-cash stock based compensation and $11.5 million for the increase in the capital contributions payable to Mountain Valley Pipeline, LLC.

Recently Issued Accounting Standards: In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers. The standard requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers at an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The Company adopted this standard on January 1, 2018 using the modified retrospective method of adoption. Adoption of the ASU did not require an adjustment to the opening balance of equity. For the disclosures required by this ASU, see Note 4.

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments-Overall: Recognition and Measurement of Financial Assets and Financial Liabilities. The standard affects accounting for equity investments and financial liabilities under the fair value option, the presentation and disclosure requirements for financial instruments, and eliminates the cost method of accounting for equity investments. The Company adopted this standard in the first quarter of 2018 which resulted in a cumulative effect adjustment of $4.1 million on the Statement of Consolidated Equity.

In February 2016, the FASB issued ASU No. 2016-02, Leases. The primary effect of adopting the new standard on leases will be to record assets and liabilities for contracts currently recognized as operating leases. In July 2018, the FASB issued targeted improvements to this ASU in ASU 2018-11. This update provides entities with an optional transition method, which permits an entity to initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company adopted the ASUs using the optional transition method on January 1, 2019 and did not require an adjustment to the opening balance of equity. The Company has adopted the practical expedient package, the land easement and short-term lease recognition exemption provided for under the new standard. The Company also elected a practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a lease.

The quantitative impacts of the new standard are dependent on the leases in existence at the time of reporting. As a result, the evaluation of the effect of the new standard on the results of operations and liquidity will change as new leases are entered into in the future. However, the Company does not expect the standard to have a significant impact on its results of operations or liquidity in 2019. In 2019, the Company expects to record a lease liability and offsetting right of use asset between $100 million and $125 million on the Consolidated Balance Sheet sheet associated with its leases which are primarily related to facilities, production rigs and compressors.

Additional disclosures will be required to describe the nature, amount, significant assumptions and judgments made, maturity analysis of its lease liabilities and accounting policy elections from leases. The Company has implemented a new lease

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accounting system and related processes to ensure that contracts that contain lease components are appropriately accounted for under ASC Topic 842, including both new contracts and modifications to existing contracts.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current GAAP and requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. The ASU will be effective for annual reporting periods beginning after December 15, 2019, including interim periods within that reporting period. The Company is currently evaluating the impact this standard will have on its financial statements and related disclosures.

In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows: Restricted Cash. This ASU requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts shown on the statement of cash flows. The Company adopted this standard in the first quarter of 2018. The Company had $75 million in restricted cash at December 31, 2016. In accordance with ASU 2016-18, restricted cash is included in the beginning of period cash balance and excluded from investing activities on the Statements of Consolidated Cash Flows for the year ended December 31, 2017. The Company had no restricted cash on the Consolidated Balance Sheet at December 31, 2018 or 2017.

In January 2017, the FASB issued ASU No. 2017-01, Business Combinations: Clarifying the Definition of a Business. This ASU clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Company adopted this standard in the first quarter of 2018 with no significant effect on its financial statements or related disclosures.

In January 2017, the FASB issued ASU No. 2017-04, Simplifying the Test of Goodwill Impairment. This ASU simplifies the quantitative goodwill impairment test requirements by eliminating the requirement to calculate the implied fair value of goodwill. Instead, a company is required to record an impairment charge based on the excess of a reporting unit's carrying value over its fair value. The standard's provisions are to be applied prospectively. The Company adopted this standard in the first quarter of 2018 with no significant effect on its financial statements or related disclosures. However as discussed in Note 3, the Company has recorded an impairment charge in 2018 under this standard.

In March 2017, the FASB issued ASU No. 2017-07, Compensation - Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This ASU provides additional guidance on the presentation of net benefit cost in the income statement and on the components eligible for capitalization in assets. The Company adopted this standard in the first quarter of 2018 with no significant effect on its financial statements or related disclosures.

In May 2017, the FASB issued ASU No. 2017-09, Compensation - Stock Compensation: Scope of Modification Accounting. This ASU provides guidance regarding which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. The Company adopted this standard in the first quarter of 2018 with no significant effect on its financial statements or related disclosures. This ASU will be applied prospectively to awards modified on or after the adoption date.

In February 2018, the FASB issued ASU No. 2018-02, Income Statement—Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. This ASU allows companies to reclassify stranded tax effects resulting from the Tax Cuts and Jobs Act from accumulated other comprehensive income to retained earnings. The ASU is effective for fiscal years beginning after December 15, 2018 and early adoption is permitted. The reclassification permitted under this ASU should be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the Tax Cuts and Jobs Act is recognized. The Company adopted the ASU on January 1, 2019 with an immaterial adjustment to other comprehensive income.

In August 2018, the FASB issued ASU No. 2018-13, Fair Value Measurement, Changes to the Disclosure Requirements for Fair Value Measurement, which makes a number of changes to the hierarchy associated with Level 1, 2 and 3 fair value measurements and the related disclosure requirements. This guidance is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. Early adoption is permitted. The Company is currently evaluating the effect this standard will have on its financial statements and related disclosures but does not expect the adoption of this standard to have a material impact on its financial statements and related disclosures.

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Subsequent Events: The Company has evaluated subsequent events through the date of the financial statement issuance.

2. Separation and Distribution and Discontinued Operations

On November 12, 2018, EQT completed the previously announced separation of its midstream business, which was composed of the separately operated natural gas gathering, transmission and storage, and water services businesses of EQT, from its upstream business, which is composed of the natural gas, oil and natural gas liquids development, production and sales and commercial operations of the Company (the Separation). The Separation was effected by the transfer of the midstream business from EQT to Equitrans Midstream and the distribution of 80.1% of the outstanding shares of Equitrans Midstream common stock to EQT's shareholders (the Distribution). EQT's shareholders of record as of the close of business on November 1, 2018 (the Record Date) received 0.80 shares of Equitrans Midstream common stock for every one share of EQT common stock held as of the close of business on the Record Date. EQT retained 19.9% of the outstanding shares of Equitrans Midstream common stock. EQT does not have the ability to exercise significant influence and does not have a controlling financial interest in Equitrans Midstream or any of its subsidiaries. As such, this investment is accounted for as an investment in equity securities. As of December 31, 2018, the fair value was based on the closing stock price of Equitrans Midstream multiplied by the number of shares of common stock owned by the Company. The changes in fair value since November 12, 2018 were recorded in other expense in the Statement of Consolidated Operations and resulted in an unrealized loss of approximately $72.4 million.

On November 12, 2018, in connection with the Separation and Distribution, the Company entered into several agreements with Equitrans Midstream to implement the legal and structural separation between the two companies, govern the relationship between the Company and Equitrans Midstream, and allocate between the Company and Equitrans Midstream various assets, liabilities and obligations, including, among other things, employee benefits, litigation, contracts, equipment, real property, intellectual property, and tax-related assets and liabilities. These agreements include a Separation and Distribution Agreement, Tax Matters Agreement, Employee Matters Agreement, Transition Services Agreement and Shareholder and Registration Rights Agreement. The Transition Services Agreement will terminate upon the earlier of (i) the expiration of the term of the last service provided under it, or (ii) November 12, 2019.

In the ordinary course of business, the Company engages in transactions with EQM Midstream Partners, LP (EQM) and its affiliates including, but not limited to, gas gathering agreements, transportation service and precedent agreements, storage agreements and water services agreements. These agreements have terms ranging from month-to-month up to 20 years.

Equitrans Midstream included all of the Company's former EQM Gathering, EQM Transmission and EQM Water segments. The Statements of Consolidated Operations and Consolidated Balance Sheets of Equitrans Midstream are reflected as discontinued operations for all periods presented. Prior periods have been recast to reflect this presentation. This recast also includes presenting certain transportation and processing expenses in continuing operations for all periods presented which were previously eliminated in consolidation prior to the Separation and Distribution. The cash flows related to Equitrans Midstream have not been segregated and are included within the Statements of Consolidated Cash Flows for all periods presented.

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The results of operations of Equitrans Midstream are presented as discontinued operations in the Statements of Consolidated Operations as summarized below. The Company allocated all of the transaction costs associated with the Separation and Distribution to discontinued operations. The transaction costs included in the table below also included amounts that the Company allocated to discontinued operations for the Rice Merger (see Note 3).

	January 1, 2018 to November 12, 2018	Years Ended December 31, 2017	2016
	(Thousands)		
Operating revenues	$388,854	$279,422	$217,952
Transportation and processing	(803,858)	(604,025)	(514,373)
Operation and maintenance	99,671	80,833	69,308
Selling, general and administrative	62,702	53,275	44,022
Depreciation	160,701	106,574	71,469
Impairment/loss on sale of long-lived assets	—	—	59,748
Impairment of goodwill (a)	267,878	—	—
Transaction costs	93,062	85,124	—
Amortization of intangible assets	36,007	5,540	—
Other income	51,014	26,610	28,718
Interest expense	88,300	34,801	16,761
Income from discontinued operations before income taxes	435,405	543,910	499,735
Income tax expense	61,643	72,797	99,305
Income from discontinued operations after income taxes	373,762	471,113	400,430
Less: Net income from discontinued operations attributable to noncontrolling interests	237,410	349,613	321,920
Net income from discontinued operations	$136,352	$121,500	$78,510

(a) Following the third quarter of 2018 and prior to the Separation and Distribution, indicators of goodwill impairment were identified in the form of the announced production curtailments that could reduce volumetric-based fee revenues of two reporting units to which the Company's goodwill was recorded. The two reporting units were Rice Retained Midstream and RMP PA Gas Gathering, which were allocated to discontinued operations as a result of the Separation and Distribution. Both of these reporting units earn a substantial portion of their revenues from volumetric-based fees, which are sensitive to changes in development plans. In estimating the fair value of these reporting units, a combination of the income approach and the market approach were utilized. The discounted cash flow method income approach applies significant inputs not observable in the public market (Level 3), including estimates and assumptions related to future throughput volumes, operating costs, capital spending and changes in working capital. The comparable company method market approach and reference transaction method evaluates the value of a company using metrics of other businesses of similar size and industry. The reference transaction method evaluates the value of a company based on pricing multiples derived from similar transactions entered into by similar companies.

For the year ended December 31, 2018, the fair value of the Rice Retained Midstream reporting unit was greater than its carrying value; however, the carrying value of the RMP PA Gas Gathering reporting unit exceeded its fair value. As a result, impairment of goodwill of $267.9 million was recorded with a corresponding decrease to goodwill on the Consolidated Balance Sheet and allocated to discontinued operations.

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The carrying amount of the major classes of assets and liabilities related to Equitrans Midstream classified as assets and liabilities of discontinued operations in the Consolidated Balance Sheet at December 31, 2017 are presented in the below table.

	December 31, 2017 (Thousands)
Total assets of discontinued operations	
Cash and cash equivalents	$121,004
Accounts receivable, net	60,551
Prepaid expenses and other (a)	(25,295)
Current assets of discontinued operations	156,260
Net property, plant and equipment	5,155,007
Intangible assets, net	617,660
Goodwill	1,527,877
Investment in nonconsolidated entity	460,546
Other assets	28,168
Noncurrent assets of discontinued operations	7,789,258
Total assets of discontinued operations	$7,945,518
Total liabilities of discontinued operations	
Accounts payable (a)	$(71,809)
Other current liabilities	151,842
Current liabilities of discontinued operations	80,033
Credit facility borrowings	466,000
Senior Notes	987,352
Deferred income taxes	(121,062)
Notes payable to EQM Midstream Partners, LP (See Note 10)	(114,720)
Other liabilities and credits	30,462
Noncurrent liabilities of discontinued operations	1,248,032
Total liabilities of discontinued operations	$1,328,065

(a) As of December 31, 2017, prepaid expenses and other represents the receivable from Equitrans Midstream and accounts payable represents the payable to Equitrans Midstream.

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The following table presents amounts of the discontinued operations related to Equitrans Midstream which are included in the Statements of Consolidated Cash Flows.

	January 1, 2018 to November 12, 2018	Years Ended December 31, 2017	2016
	(Thousands)		
Operating activities:			
Deferred income tax (benefit) expense	$(373,405)	$43,471	$(21,936)
Depreciation	160,701	106,574	71,469
Amortization of intangibles	36,007	5,540	—
Asset impairments	—	—	59,748
Goodwill impairment	267,878	—	—
Other income	(51,450)	(27,281)	(29,300)
Share-based compensation expense	$1,841	$468	$373
Investing activities:			
Capital expenditures	$(732,727)	$(380,151)	$(584,819)
Capital contributions to Mountain Valley Pipeline, LLC (a)	(820,943)	(159,550)	(98,399)
Sales of interests in Mountain Valley Pipeline, LLC (a)	$—	$—	$12,533
Financing activities:			
Net proceeds from the issuance of common units of EQM	$—	$—	$217,102
Proceeds from issuance of debt	2,500,000	—	500,018
Increase in borrowings on credit facilities	3,378,500	544,084	740,000
Repayment of borrowings on credit facilities	(3,219,500)	(344,000)	(1,039,000)
Distributions to noncontrolling interests	(380,651)	(236,123)	(189,981)
Contribution to Strike Force Midstream LLC by minority owner, net of distribution	—	6,738	—
Acquisition of 25% of Strike Force Midstream LLC	(175,000)	—	—
Debt issuance costs and revolving credit facility origination fees	$(40,966)	$(2,257)	$(8,580)

(a) The Mountain Valley Pipeline, LLC is a joint venture that is constructing the Mountain Valley Pipeline (MVP). EQM owns an interest in the joint venture and made capital contributions to the joint venture.

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3. Rice Merger

On November 13, 2017, the Company completed its previously announced acquisition of Rice Energy Inc. (Rice) pursuant to the Agreement and Plan of Merger, dated as of June 19, 2017 (as amended, the Merger Agreement), by and among the Company, Rice and a wholly owned indirect subsidiary of the Company (RE Merger Sub). Pursuant to the terms of the Merger Agreement, on November 13, 2017, RE Merger Sub merged with and into Rice (the Rice Merger) with Rice continuing as the surviving corporation and a wholly owned indirect subsidiary of the Company. Immediately after the effective time of the Rice Merger (the Effective Time), Rice merged with and into another wholly owned indirect subsidiary of the Company.

At the Effective Time, each share of the common stock, par value $0.01 per share, of Rice (the Rice Common Stock) issued and outstanding immediately prior to the Effective Time was converted into the right to receive 0.37 (the Exchange Ratio) of a share of the common stock, no par value, of the Company (Company Common Stock) and $5.30 in cash (collectively, the Merger Consideration). The aggregate Merger Consideration consisted of approximately 91 million shares of Company Common Stock and approximately $1.6 billion in cash (net of cash acquired and inclusive of amounts payable to employees of Rice who did not continue with the Company following the Effective Time). See Note 13 for further details.

In connection with the closing of the Rice Merger, the Company paid an aggregate of $555.5 million, included in the cash paid for the Merger Consideration of approximately $1.6 billion (net of cash acquired and inclusive of amounts payable to employees of Rice who did not continue with the Company following the Effective Time), to affiliates of EIG Global Energy Partners (collectively, the EIG Funds) to redeem the EIG Funds' respective interests in Rice Midstream Holdings LLC (Rice Midstream Holdings) and Rice Midstream GP Holdings, LP (the EIG Redemptions). Following the EIG Redemptions, each of Rice Midstream Holdings and Rice Midstream GP Holdings, LP became indirect wholly owned subsidiaries of the Company.

In connection with the closing of the Rice Merger, the Company repaid the $321.0 million of outstanding principal under Rice Energy Operating LLC's revolving credit facility and the $187.5 million of outstanding principal under Rice Midstream Holdings' revolving credit facility, together with interest and fees of $1.4 million and $0.3 million, respectively, and the credit agreements were terminated.

Also in connection with the Rice Merger, Rice redeemed and canceled all of its outstanding 6.25% Senior Notes due 2022 (the Rice 2022 Notes) and 7.25% Senior Notes due 2023 (the Rice 2023 Notes) on November 13, 2017. The Company made aggregate payments of $1.4 billion in connection with the note redemptions, including make whole call premiums of $42.2 million and $21.6 million for the Rice 2022 Notes and the Rice 2023 Notes, respectively, and $13.4 million of required interest payments on the Rice 2023 Notes.

The Company acquired a total of approximately 270,000 net acres through the Rice Merger, which included approximately 205,000 net Marcellus acres, as well as approximately 65,000 net Utica acres in Ohio. The Company also acquired Upper Devonian and Utica drilling rights held in Pennsylvania.

The Company recorded $25.4 million and $152.2 million in transaction costs in continuing operations and $13.5 million and $85.1 million in discontinued operations related to the Rice Merger during the years ended December 31, 2018 and 2017, respectively. Also, in 2017, the Company expensed $8.0 million in debt issuance costs related to a bridge financing commitment to support the Rice Merger, $5.1 million of which is in continuing operations and $2.9 million of which is in discontinued operations.

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Allocation of Purchase Price

The Rice Merger was accounted for as a business combination, using the acquisition method. The following table summarizes the final purchase price and fair values of assets and liabilities assumed as of November 13, 2017, with any excess of the purchase price over the fair value of the identified net assets acquired recorded as goodwill. Variances between the preliminary and final purchase price allocations related to standard closing purchase price adjustments.

	Final Purchase Price Allocation (Thousands)
Consideration Given:	
Equity consideration	$5,943,289
Cash consideration	1,299,407
Buyout of preferred equity in Rice Midstream Holdings	429,708
Buyout of common units in Rice Midstream GP Holdings, LP	125,828
Settlement of pre-existing relationships	(14,699)
Total consideration	7,783,533
Fair value of liabilities assumed:	
Current liabilities	577,053
Long-term debt	2,151,656
Deferred income taxes	1,106,773
Other long term liabilities	95,712
Amount attributable to liabilities assumed	3,931,194
Fair value of assets acquired:	
Cash	294,671
Accounts receivable	322,630
Current assets	109,465
Net property, plant and equipment	9,918,315
Intangible assets	747,300
Noncontrolling interests	(1,715,611)
Amount attributable to assets acquired	9,676,770
Goodwill from Rice Merger	$2,037,957
Goodwill impairment - continuing operations	(530,811)
Goodwill impairment - discontinued operations	(267,878)
Goodwill allocated to discontinued operations (a)	(1,239,268)
Goodwill as of December 31, 2018	$—

(a) In conjunction with the Rice Merger, the Company had unamortized carryover tax basis of $387.1 million of tax deductible goodwill, of which the entire amount relates to discontinued operations.

The fair values of natural gas and oil properties were based on inputs that were not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using valuation techniques that convert future cash flows into a single discounted amount. Significant inputs to the valuation of natural gas and oil properties included estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average cost of capital. These inputs had a significant impact on the valuation of oil and gas properties. The fair value of undeveloped property was determined based upon a market approach of comparable transactions using Level 3 inputs.

The estimated fair value of midstream facilities and equipment, generally consisting of pipeline systems and compression stations, is estimated using the cost approach. Significant unobservable inputs in the estimate of fair value include management’s assumptions about the replacement costs for similar assets, the relative age of the acquired assets and any potential economic or functional obsolescence associated with the acquired assets. As a result, the estimated fair value of the midstream facilities and equipment represents a Level 3 fair value measurement.

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The non-controlling interest in the acquired business was comprised of the limited partner units in Rice Midstream Partners LP (RMP) which were not acquired by the Company as well as the non-controlling interest in Strike Force Midstream LLC (Strike Force Midstream). The RMP limited partner units were actively traded on the New York Stock Exchange, and were valued based on observable market prices as of the transaction date and therefore represent a Level 1 fair value measurement. The non-controlling interest in Strike Force Midstream was calculated based on the enterprise value of Strike Force Midstream and the percentage ownership not acquired by the Company. Significant unobservable inputs in the estimate of the enterprise value of Strike Force Midstream include the future revenue estimates and future cost assumptions. As a result, the non-controlling interest in Strike Force Midstream represents a Level 3 fair value measurement.

The Company identified intangible assets for customer relationships with third party customers and non-compete agreements with certain former Rice executives. The fair value of the identified intangible assets was determined using the income approach which requires a forecast of the expected future cash flows generated and an estimated market-based weighted average cost of capital. Significant unobservable inputs in the determination of fair value include future production levels, future revenues estimates, future cost assumptions, the estimated probability that former executives would compete in the absence of such non-compete agreements and estimated customer retention rates. As a result, the estimated fair value of the identified intangible assets represents a level 3 fair value measurement.

4. Revenue from Contracts with Customers

As discussed in Note 1, the Company adopted ASU No. 2014-09, Revenue from Contracts with Customers (Topic 606), on January 1, 2018 using the modified retrospective method of adoption. Adoption of the ASU did not require an adjustment to the opening balance of equity and did not materially change the Company's amount and timing of revenues. The Company applied the ASU only to contracts that were not completed as of January 1, 2018. The Company has elected to exclude all taxes from the measurement of transaction price.

For the sale of natural gas, oil and NGLs, the Company generally considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery. These contracts typically require payment within 25 days of the end of the calendar month in which the gas is delivered. A significant number of these contracts contain variable consideration because the payment terms refer to market prices at future delivery dates. In these situations, the Company has not identified a standalone selling price because the terms of the variable payments relate specifically to the Company’s efforts to satisfy the performance obligations. Other contracts contain fixed consideration (i.e. fixed price contracts or contracts with a fixed differential to New York Mercantile Exchange (NYMEX) or index prices). The fixed consideration is allocated to each performance obligation on a relative standalone selling price basis, which requires judgment from management. For these contracts, the Company generally concludes that the fixed price or fixed differentials in the contracts are representative of the standalone selling price.

Based on management’s judgment, the performance obligations for the sale of natural gas, oil and NGLs are satisfied at a point in time because the customer obtains control and legal title of the asset when the natural gas, oil or NGLs are delivered to the designated sales point.

The sales of natural gas, oil and NGLs as presented on the Statements of Consolidated Operations represent the Company’s share of revenues net of royalties and excluding revenue interests owned by others. When selling natural gas, oil and NGLs on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis.

Because the Company's performance obligations have been satisfied and an unconditional right to consideration exists as of the balance sheet date, the Company has recognized amounts due from contracts with customers of $783.0 million as accounts receivable within the Consolidated Balance Sheet.

The table below provides disaggregated information regarding the Company’s revenues. Certain contracts that provide for the release of capacity that is not used to transport the Company’s produced volumes were deemed to be outside the scope of Revenue from Contracts with Customers. The cost of, and recoveries on, that capacity are reported within net marketing services and other. Derivative contracts are also outside the scope of Revenue from Contracts with Customers.

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Year Ended December 31, 2018	Revenues from contracts with customers	Other sources of revenue	Total
	(Thousands)		
Natural gas sales	$4,217,684	$—	$4,217,684
NGLs sales	442,010	—	442,010
Oil sales	35,825	—	35,825
Sales of natural gas, oil and NGLs	$4,695,519	$—	$4,695,519
Net marketing services and other	13,865	27,075	40,940
Loss on derivatives not designated as hedges	—	(178,591)	(178,591)
Total operating revenues (losses)	$4,709,384	$(151,516)	$4,557,868

The following table includes the transaction price allocated to the Company's remaining performance obligations on all contracts with fixed consideration. The table excludes all contracts that qualified for the exception to the relative standalone selling price method.

	2019	2020	Total
	(Thousands)		
Natural gas sales	$54,116	$21,485	$75,601

5. Derivative Instruments

The Company's primary market risk exposure is the volatility of future prices for natural gas and NGLs, which can affect the operating results of the Company. The Company's overall objective in its hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices.

The derivative commodity instruments currently utilized by the Company are primarily fixed price swap agreements, collar agreements and option agreements which may require payments to or receipt of payments from counterparties based on the differential between two prices for the commodity. The Company uses these agreements to hedge its NYMEX and basis exposure. The Company may also use other contractual agreements in implementing its commodity hedging strategy. The Company may engage in interest rate swaps to hedge exposure to fluctuations in interest rates. The Company's over the counter (OTC) derivative commodity instruments are typically placed with financial institutions and the creditworthiness of all counterparties is regularly monitored.

The Company recognizes all derivative instruments as either assets or liabilities at fair value on a gross basis. These derivative instruments are reported as either current assets or current liabilities due to their highly liquid nature. The Company can net settle its derivative instruments at any time.

The Company discontinued cash flow hedge accounting in 2014; therefore, all changes in fair value of the Company's derivative instruments are recognized within operating revenues in the Statements of Consolidated Operations.

In connection with the Rice Merger, the Company assumed all outstanding derivative commodity instruments held by Rice. The assets and liabilities assumed were recognized at fair value at the closing date and subsequent changes in fair value were recognized within operating revenues in the Statements of Consolidated Operations. The derivative commodity instruments assumed were substantially similar to instruments previously held by the Company.

Contracts which result in physical delivery of a commodity expected to be sold by the Company in the normal course of business are designated as normal sales and are exempt from derivative accounting. If contracts that result in the physical receipt or delivery of a commodity are not designated or do not meet all the criteria to qualify for the normal purchase and normal sale scope exception, then the contracts are subject to derivative accounting.

OTC arrangements require settlement in cash. The Company also enters into exchange traded derivative commodity instruments that are generally settled with offsetting positions. Settlements of derivative commodity instruments are reported as a component of cash flows from operations in the accompanying Statements of Consolidated Cash Flows.

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With respect to the derivative commodity instruments held by the Company, the Company hedged portions of expected sales of equity production and portions of its basis exposure covering approximately 3,128 Bcf of natural gas and 1,505 Mbbls of NGLs as of December 31, 2018, and 2,148 Bcf of natural gas and 1,460 Mbbls of NGLs as of December 31, 2017. The open positions at December 31, 2018 and December 31, 2017 had maturities extending through December 2024 and December 2022, respectively.

When the net fair value of any of the Company's swap agreements represents a liability to the Company which is in excess of the agreed-upon threshold between the Company and the counterparty, the counterparty requires the Company to remit funds as a margin deposit for the derivative liability which is in excess of the threshold amount. The Company records these deposits as a current asset. When the net fair value of any of the Company's swap agreements represents an asset to the Company which is in excess of the agreed-upon threshold between the Company and the counterparty, the Company requires the counterparty to remit funds as margin deposits in an amount equal to the portion of the derivative asset which is in excess of the threshold amount. The Company records a current liability for such amounts received. The Company had no such deposits in its Consolidated Balance Sheets as of December 31, 2018 or 2017.

When the Company enters into exchange-traded natural gas contracts, exchanges may require the Company to remit funds to the corresponding broker as good-faith deposits to guard against the risks associated with changing market conditions. The Company must make such deposits based on an established initial margin requirement as well as the net liability position, if any, of the fair value of the associated contracts. The Company records these deposits as a current asset in the Consolidated Balance Sheets. In the case where the fair value of such contracts is in a net asset position, the broker may remit funds to the Company, in which case the Company records a current liability for such amounts received. The initial margin requirements are established by the exchanges based on the price, volatility and the time to expiration of the related contract. The margin requirements are subject to change at the exchanges' discretion. The Company recorded current assets of $40.3 million as of December 31, 2018 for such deposits in its Consolidated Balance Sheets. The Company had no such deposits in its Consolidated Balance Sheets as of December 31, 2017.

The Company has netting agreements with financial institutions and its brokers that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities. The table below reflects the impact of netting agreements and margin deposits on gross derivative assets and liabilities as of December 31, 2018 and 2017.

As of December 31, 2018	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting agreements	Margin deposits remitted to counterparties	Derivative instruments, net
	(Thousands)			
Asset derivatives:				
Derivative instruments, at fair value	$481,654	$(256,087)	$ —	$ 225,567
Liability derivatives:				
Derivative instruments, at fair value	$336,051	$(256,087)	$ (40,283)	$ 39,681

As of December 31, 2017	Derivative instruments, recorded in the Consolidated Balance Sheet, gross	Derivative instruments subject to master netting agreements	Margin deposits remitted to counterparties	Derivative instruments, net

	(Thousands)			
Asset derivatives:				
Derivative instruments, at fair value	$241,952	$(86,856)	$ —	$ 155,096
Liability derivatives:				
Derivative instruments, at fair value	$139,089	$(86,856)	$ —	$ 52,233

Certain of the Company’s derivative instrument contracts provide that if the Company’s credit ratings by Standard & Poor’s Ratings Service (S&P) or Moody’s Investors Service (Moody's) are lowered below investment grade, additional collateral must be deposited with the counterparty if the amounts outstanding on those contracts exceed certain thresholds. The additional collateral can be up to 100% of the derivative liability. As of December 31, 2018, the aggregate fair value of all derivative instruments with credit risk-related contingent features that were in a net liability position was $110.7 million, for which the Company had no collateral posted on December 31, 2018. If the Company’s credit rating by S&P or Moody’s had been downgraded below investment

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grade on December 31, 2018, the Company would not have been required to post any additional collateral under the agreements with the respective counterparties. The required margin on the Company's derivative instruments is subject to significant change as a result of factors other than credit rating, such as gas prices and credit thresholds set forth in agreements between the hedging counterparties and the Company. Investment grade refers to the quality of the Company’s credit as assessed by one or more credit rating agencies. The Company’s senior unsecured debt was rated BBB- by S&P and Baa3 by Moody’s at December 31, 2018. In order to be considered investment grade, the Company must be rated BBB- or higher by S&P and Baa3 or higher by Moody’s. Anything below these ratings is considered non-investment grade. See also "Security Ratings and Financing Triggers" under Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

6. Fair Value Measurements

The Company records its financial instruments, principally derivative instruments, at fair value in its Consolidated Balance Sheets. The Company estimates the fair value using quoted market prices, where available. If quoted market prices are not available, fair value is based upon models that use market-based parameters as inputs, including forward curves, discount rates, volatilities and nonperformance risk. Nonperformance risk considers the effect of the Company’s credit standing on the fair value of liabilities and the effect of the counterparty’s credit standing on the fair value of assets. The Company estimates nonperformance risk by analyzing publicly available market information, including a comparison of the yield on debt instruments with credit ratings similar to the Company’s or counterparty’s credit rating and the yield of a risk-free instrument and credit default swaps rates where available.

The Company has categorized its assets and liabilities recorded at fair value into a three-level fair value hierarchy, based on the priority of the inputs to the valuation technique. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets and liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Assets and liabilities in Level 2 primarily include the Company’s swap, collar and option agreements.

Exchange traded commodity swaps are included in Level 1. The fair value of the commodity swaps included in Level 2 is based on standard industry income approach models that use significant observable inputs, including but not limited to NYMEX natural gas forward curves, LIBOR-based discount rates, basis forward curves and natural gas liquids forward curves. The Company’s collars and options are valued using standard industry income approach option models. The significant observable inputs utilized by the option pricing models include NYMEX forward curves, natural gas volatilities and LIBOR-based discount rates. The NYMEX natural gas forward curves, LIBOR-based discount rates, natural gas volatilities, basis forward curves and NGLs forward curves are validated to external sources at least monthly.

The following assets and liabilities were measured at fair value on a recurring basis during the applicable period:

		Fair value measurements at reporting date using		
Description	As of December 31, 2018	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(Thousands)			
Assets				
Derivative instruments, at fair value	$481,654	$ 112,107	$ 369,547	$ —
Liabilities				
Derivative instruments, at fair value	$336,051	$ 126,582	$ 209,469	$ —

Fair value measurements at reporting date using

Description	As of December 31, 2017	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(Thousands)			
Assets				
Derivative instruments, at fair value	$241,952	$ —	$ 241,952	$ —
Liabilities				
Derivative instruments, at fair value	$139,089	$ —	$ 139,089	$ —

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The carrying values of cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturity of the instruments. The carrying value of the Equitrans Midstream investment approximates fair value as it was based on the closing stock price of Equitrans Midstream common stock multiplied by the number of shares of common stock of Equitrans Midstream owned by the Company. The carrying values of borrowings under the Company's credit facility approximate fair value as the interest rates are based on prevailing market rates.

The Company also has an immaterial investment in a fund that invests in companies developing technology and operating solutions for exploration and production companies for which it recognized a cumulative effect of accounting change in the first quarter 2018. The investment is valued using the net asset value as a practical expedient as provided in the financial statements received from fund managers.

The Company estimates the fair value of its Senior Notes using its established fair value methodology. Because not all of the Company’s Senior Notes are actively traded, the fair value of the Senior Notes is a Level 2 fair value measurement. The estimated fair value of Senior Notes on the Consolidated Balance Sheets at December 31, 2018 and 2017 was approximately $4.4 billion and $4.7 billion, respectively. The carrying value of Senior Notes on the Consolidated Balance Sheets at December 31, 2018 and 2017 was approximately $4.6 billion for both periods. The fair value of the note payable to EQM is a Level 3 fair value measurement which is estimated using an income approach model utilizing a market-based discount rate. The estimated fair value of the note payable to EQM on the Consolidated Balance Sheets at December 31, 2018 and 2017 was approximately $121.8 million and $133.0 million, respectively. The carrying value of the note payable to EQM on the Consolidated Balance Sheets at December 31, 2018 and 2017 was approximately $114.7 million and $119.1 million, respectively. Refer to Note 10 for further information regarding the Company's debt as of December 31, 2018 and 2017.

The Company recognizes transfers between Levels as of the actual date of the event or change in circumstances that caused the transfer. There were no transfers between Levels 1, 2 and 3 during the periods presented.

For information on the fair values of assets related to the impairments of proved and unproved oil and gas properties and of other long-lived assets, the assets acquired in the Rice Merger and the assets acquired in other acquisition transactions, see Notes 1, 3, and 7.

7. Acquisitions

In addition to the Rice Merger discussed in Note 3, the Company executed multiple transactions during 2016 and 2017 that resulted in the Company's acquisition of approximately 304,000 net Marcellus acres, including the transactions listed below:

- On July 8, 2016, the Company acquired approximately 62,500 net Marcellus acres and 31 Marcellus wells, 24 of which were producing, from Statoil USA Onshore Properties, Inc. The net acres acquired are primarily located in Wetzel, Tyler and Harrison Counties of West Virginia.

- In the fourth quarter of 2016, the Company acquired approximately 42,600 net Marcellus acres and 42 Marcellus wells, 32 of which were producing at the time of the acquisition, which were being jointly developed by Trans Energy, Inc. (Trans Energy) and Republic Energy Ventures, LLC and its affiliates (collectively, Republic). The net acres acquired are primarily located in Wetzel, Marshall and Marion Counties of West Virginia. The acquisitions were effected through simultaneous transaction agreements that were executed on October 24, 2016 including: (i) a purchase and sale agreement between the Company and Republic; and (ii) an agreement and plan of merger among the Company, a wholly owned subsidiary of the Company (TE Merger Sub) and Trans Energy. The Republic acquisition closed on November 3, 2016. On October 27, 2016, the Company commenced a tender offer, through its wholly owned subsidiary, to acquire the outstanding shares of common stock of Trans Energy, a publicly traded company, at an offer price of $3.58 per share in cash. Following the tender offer on December 5, 2016, TE Merger Sub merged with and into Trans Energy, at which time Trans Energy became an indirect wholly owned subsidiary of the Company (the Trans Energy Merger).

- On December 16, 2016, the Company acquired approximately 17,000 net Marcellus acres located in Washington, Westmoreland and Greene Counties of Pennsylvania, and two related Marcellus wells both of which were producing from a third party.

- On February 1, 2017, the Company acquired approximately 14,000 net Marcellus acres located in Marion, Monongalia and Wetzel Counties of West Virginia from a third party.

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- On February 27, 2017, the Company acquired approximately 85,000 net Marcellus acres, including drilling rights on approximately 44,000 net Utica acres and current natural gas production of approximately 110 MMcfe per day, from Stone Energy Corporation. The acquired acres are primarily located in Wetzel, Marshall, Tyler and Marion Counties of West Virginia. The acquired assets also included 174 Marcellus wells, 120 of which were producing at the time of the acquisition, and 20 miles of gathering pipeline.

- On June 30, 2017, the Company acquired approximately 11,000 net Marcellus acres, and the associated Utica drilling rights, from a third party. The acquired acres are primarily located in Allegheny, Washington and Westmoreland Counties of Pennsylvania.

In total, the Company paid net cash of $740.1 million during the year ended December 31, 2017 for the 2017 acquisitions previously described. The fair value assigned to the acquired property, plant and equipment from the 2017 acquisitions as of the opening balance sheet dates totaled $750.1 million. In connection with the 2017 acquisitions, the Company assumed $5.3 million of net current liabilities and $4.7 million of non-current liabilities.

During the year ended December 31, 2017, the Company paid $78.9 million for additional undeveloped acreage as a result of post-closing adjustments on its 2016 acquisitions disclosed above and recorded other non-cash adjustments which reduced the fair values assigned to the acquired property, plant and equipment by $14.3 million.

In total, the Company paid $1,130.1 million in net cash in connection with the 2016 acquisitions previously described. The fair value assigned to the acquired property, plant and equipment as of the opening balance sheet dates totaled $1,203.4 million: $256.2 million allocated to the acquired producing wells and $947.2 million allocated to undeveloped leases. In connection with the Trans Energy Merger, the Company also acquired $1.2 million of other non-current assets and assumed $14.4 million of current liabilities and $11.1 million of non-current liabilities. The $14.4 million of current liabilities included a $5.1 million note payable; the Company repaid this note in 2016. The Company also recorded a deferred tax liability of $49.0 million due to differences in the tax and book basis of the acquired assets and liabilities.

Fair Value Measurement

As these acquisitions qualified as business combinations under GAAP, the fair value of the acquired assets was determined using a market approach for the undeveloped acreage and a discounted cash flow model under the income approach for the wells. Significant unobservable inputs used in the analysis included the determination of estimated developed reserves and forward pricing estimates. As a result, valuation of the acquired assets was a Level 3 measurement.

8. Divestitures

On June 19, 2018, the Company sold its non-core Permian Basin assets located in Texas for net proceeds of $56.9 million (the Permian Divestiture). The assets sold in the Permian Divestiture included approximately 970 productive wells with current net production of approximately 20 MMcfe per day, approximately 350 miles of low-pressure gathering lines and 26 compressors.

On July 18, 2018, the Company sold approximately 2.5 million non-core, net acres in the Huron play for net proceeds of $523.6 million, subject to final purchase price adjustments (the Huron Divestiture). The assets sold in the Huron Divestiture included approximately 12,000 productive wells with current net production of approximately 200 MMcfe per day, approximately 6,400 miles of low-pressure gathering lines and 59 compressor stations. The Company retained the deep drilling rights across the divested acreage.

As a result of these divestitures in 2018, the Company recorded an impairment/loss on sale of long-lived assets of $2.4 billion associated with the production and related midstream assets in the Huron and Permian plays. The impairment of these properties and related pipeline assets recorded was due to the carrying value of the assets exceeding the amounts received upon the closing of the transactions. See Note 1 for the Company's policy on impairment of proved and unproved properties.

In connection with the closing of the Huron Divestiture, the Company also recorded a loss of $260.5 million related to certain capacity contracts that the Company no longer has existing production to satisfy and does not plan to utilize in the future. The loss was recorded in the impairment/loss on sale of long-lived assets within the Statements of Consolidated Operations. The fair value of the loss for the initial measurement was based upon significant inputs that were not observable in the market and as such is considered a Level 3 fair value measurement. The key unobservable input in the calculation is the amount, if any, of potential future economic benefit from the contracts. See Note 6 for a description of the fair value hierarchy.

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On December 28, 2016, the Company sold a gathering system that primarily gathered gas for third-parties for $75.0 million. In conjunction with this transaction, the Company realized a pre-tax gain of $8.0 million, which is included in gain on sale of assets in the Statements of Consolidated Operations.

9. Income Taxes

Income tax (benefit) expense is summarized as follows:

	Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
Current:			
Federal	$(513,293)	$(89,149)	$(181,817)
State	(46,218)	(5,184)	(22,627)
Subtotal	(559,511)	(94,333)	(204,444)
Deferred:			
Federal	20,496	(1,039,769)	(110,734)
State	(157,496)	(54,314)	(47,591)
Subtotal	(137,000)	(1,094,083)	(158,325)
Total income taxes	$(696,511)	$(1,188,416)	$(362,769)

The Company recorded a current federal income tax benefit in 2018 which primarily consisted of approximately $141 million related to the refund it expects to receive as a result of its AMT credit carryforward and the Tax Cuts and Jobs Act and $16 million of current state tax expense. The current federal income tax benefit in 2017 primarily consisted of approximately $65 million related to refunds due to the Company as a result of amended returns it has filed to carry back federal and alternative minimum tax (AMT) net operating losses (NOLs) generated in 2016 and 2017. The current federal income tax benefit in 2016 consisted of approximately $83 million primarily related to amended return refund claims filed in 2016 and 2017 for open tax years 2010 through 2013. For all periods presented, the remaining current tax benefit of $435 million in 2018, $29 million in 2017 and $121 million in 2016 was offset by current expense related to discontinued operations and will not result in additional refunds to the Company.

On December 22, 2017, the U.S. Congress enacted the Tax Cuts and Jobs Act, which made significant changes to U.S. federal income tax law, including lowering the federal corporate tax rate to 21% from 35% beginning January 1, 2018. As a result of the change in the corporate tax rate the Company recorded a deferred tax benefit of $1.2 billion during the year ended December 31, 2017 to revalue its existing net deferred tax liabilities to the lower rate.

The Company applied the guidance in SAB 118 when accounting for the enactment-date effects of the Tax Cuts and Jobs Act in 2017 and throughout 2018. At December 31, 2017, the Company had not completed the accounting for all the enactment-date income tax effects of the legislation under ASC 740, Income Taxes, for the following aspects: remeasurement of deferred tax assets and liabilities and incentive-based compensation limitations. At December 31, 2018, the Company completed the accounting for all the enactment-date income tax effects of the Tax Cuts and Jobs Act. During 2018, the Company recognized adjustments of $5.3 million to the provisional amounts recorded at December 31, 2017 and included these adjustments as a component of income tax expense from continuing operations. The additional expense is primarily the result of adjustments to the increased limitations on deductible executive compensation.

The Tax Cuts and Jobs Act preserved deductibility of intangible drilling costs (IDCs) for federal income tax purposes, which allows the Company to deduct a portion of drilling costs in the year incurred and minimizes current taxes payable. Prior to 2018, IDCs were limited for AMT purposes, which has resulted in the Company paying AMT in periods when no other federal taxes were currently payable. The Tax Cuts and Jobs Act also repealed the AMT for tax years beginning January 1, 2018 and provides that existing AMT credit carryforwards can be utilized to offset current federal taxes owed in tax years 2018 through 2020. In addition, 50% of any unused AMT credit carryforwards can be refunded during these years with any remaining AMT credit carryforward being fully refunded in 2021. The Company expects to receive a refund of $128 million of AMT credits relating to its 2018 tax return. The current income tax receivable at December 31, 2018 also includes expected refunds of $11 million relating to NOL carryback claims. As of December 31, 2018, there is $295 million of AMT credit carryforward remaining, net of valuation allowances for sequestration of $13 million. As a result of an announcement by the IRS in January 2019 reversing its position that AMT refunds were subject to sequestration by the federal government at a rate equal to 6.2% of the refund, the Company will reverse the related valuation allowance in the first quarter of 2019.

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The Tax Cuts and Jobs Act also limits the deductibility of interest expense. As a result, the Company recorded a valuation allowance in 2018 for a portion of the interest expense limit imposed for separate company state income tax purposes.

The Company has federal NOL carryforwards related to the Rice Merger and NOLs generated in 2017 in excess of the amounts carried back to prior years. The Company also has NOLs acquired in the Trans Energy Merger, of which a nominal amount is available to be utilized annually over the next 20 years. The Tax Cuts and Jobs Act limits the utilization of NOLs generated after December 31, 2017 that are carried forward into future years to 80% of taxable income and eliminates the ability to carry NOLs back to earlier tax years for refunds of taxes paid. NOLs generated in 2018 and in future periods can be carried forward indefinitely.

Income tax (benefit) expense from continuing operations differed from amounts computed at the federal statutory rate of 21% for 2018 and 35% for 2017 and 2016 on pre-tax income as follows:

	Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
Tax at statutory rate	$(646,261)	$69,515	$(312,992)
Federal tax reform	5,288	(1,205,140)	—
State income taxes	(251,780)	(57,414)	(76,043)
Valuation allowance	88,785	10,680	23,808
Regulatory liability/asset	(276)	10,488	—
Federal tax credits	(2,400)	(34,956)	(4,539)
Goodwill impairment	111,470	—	—
Other	(1,337)	18,411	6,997
Income tax (benefit) expense	$(696,511)	$(1,188,416)	$(362,769)
Effective tax rate	22.6 %	(598.4)%	40.6 %

The effective tax rate for the year ended December 31, 2018 was higher than the U.S. federal statutory rate primarily as a result of state income taxes. The Company recognized additional state tax benefit as a result of the 2018 Divestitures and the resulting shift in the Company’s state apportionment in state taxing jurisdictions for natural gas and liquids sales as these sales shifted more heavily to lower taxed jurisdictions. The Company had no tax basis in the continuing operations goodwill impaired during 2018.

The effective tax rate for the year ended December 31, 2017 was lower than the U.S. federal statutory rate primarily due to the effect of the Tax Cuts and Jobs Act. The primary impact of the Tax Cuts and Jobs Act on the Company's effective tax rate was to revalue the Company's net deferred tax liability at the new corporate tax rate of 21%. The effective tax rate was also lower due to the federal tax credits generated during the year, which increased as a result of $30.2 million of federal marginal well tax credits. The IRS notice supporting the calculation of the credit was not published until 2017 and the Company was unable to estimate the amount of this credit in 2016 absent the IRS notice. As a result, $6.1 million of this credit recorded in 2017 related to 2016 activity.

For the year ended December 31, 2017, the Company realized a $10.5 million tax expense associated with FERC regulated assets as a result of the corporate tax rate reduction in the Tax Cuts and Jobs Act. Following the normalization rules of the Internal Revenue Code (IRC), this regulatory liability is amortized on a straight-line basis over the estimated remaining life of the related assets. This regulatory liability was transferred to Equitrans Midstream in connection with the Separation and Distribution and was included as part of discontinued operations.

The effective tax rate for the year ended December 31, 2016 was higher than the U.S. federal statutory rate of 35% primarily due to the tax benefit generated from pre-tax loss on state income tax paying entities.

The Company believes that it is more likely than not that the benefit from certain state NOL carryforwards and certain federal NOLs acquired in recent acquisitions will not be realized. A valuation allowance is required when it is more likely than not that all or a portion of a deferred tax asset will not be realized. All available evidence, both positive and negative, must be considered in determining the need for a valuation allowance. At December 31, 2018, 2017 and 2016, positive evidence considered included reversals of financial to tax temporary differences, the implementation of and/or ability to employ various tax planning strategies and the estimation of future taxable income. Negative evidence considered included historical pre-tax book losses of the Company's former EQT Production business segment. A review of positive and negative evidence regarding these tax benefits

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resulted in the conclusion that valuation allowances for certain NOLs were warranted as it was more likely than not that the Company would not utilize them prior to expiration. Uncertainties such as future commodity prices can affect the Company's calculations and its ability to utilize these NOLs prior to expiration. Further, the Tax Cuts and Jobs Act resulted in the Company recording a valuation allowance against a deferred tax asset related to the interest expense limitation for separate company state income tax purposes. The Tax Cuts and Jobs Act also required the Company to write-off a deferred tax asset recorded for certain incentive-based awards to be paid in a future year.

Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to the related valuation allowances in future periods that could materially impact net income.

The following table reconciles the beginning and ending amount of reserve for uncertain tax positions (excluding interest and penalties):

	2018	2017	2016
	(Thousands)		
Balance at January 1	$301,558	$252,434	$259,301
Additions based on tax positions related to current year	8,459	50,469	23,978
Additions for tax positions of prior years	14,396	8,978	20,336
Reductions for tax positions of prior years	(9,134)	(10,323)	(51,181)
Balance at December 31	$315,279	$301,558	$252,434

Included in the balance above are unrecognized tax benefits that, if recognized, would affect the effective tax rate of $124.6 million, $120.5 million and $102.0 million as of December 31, 2018, 2017 and 2016, respectively. Additionally, there were uncertain tax positions included in the balance above of $88.2 million, $84.1 million, and $75.4 million for the years ended December 31, 2018, 2017 and 2016, respectively, that have been recorded in the Consolidated Balance Sheets as a reduction of the related deferred tax asset for AMT and general business credit carryforwards and NOLs. The state deferred tax asset was reduced for uncertain tax positions of approximately $0.3 million and $0.5 million during the years ended December 31, 2017 and 2016, respectively.

Included in the tabular reconciliation above at December 31, 2018, 2017 and 2016 are $0.7 million, $4.7 million and $5.5 million, respectively, for tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of tax deductions. Any disallowance of the shorter deductibility period would accelerate the payment of cash taxes to an earlier period but would not affect the Company's annual effective tax rate.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company recorded interest and penalties of approximately $3.4 million, $3.2 million and $1.6 million for 2018, 2017 and 2016, respectively. Interest and penalties of $11.9 million, $8.4 million and $5.2 million were included in the Consolidated Balance Sheets at December 31, 2018, 2017 and 2016, respectively.

As of December 31, 2018, the Company believed that it is reasonably possible that a decrease of $33.3 million in unrecognized tax benefits related to federal tax positions may be necessary within 12 months as a result of potential settlements with, or legal or administrative guidance by, relevant taxing authorities or the lapse of applicable statutes of limitation. As of December 31, 2017, the Company believed that it is reasonably possible that a decrease of $42.5 million in unrecognized tax benefits related to federal tax positions may be necessary within 12 months. As of December 31, 2016, the Company did not expect any of its unrecognized tax benefits to decrease within the next 12 months.

The consolidated federal income tax liability of the Company has been settled with the IRS through 2009. The IRS has completed its review of the 2010, 2011 and 2012 tax years and the Company is in the process of appealing its

Research & Experimentation (R&E) tax credit claim for such years. In addition, the Company has filed refund claims relating to R&E and AMT preference adjustments for the years 2010 through 2013. These claims are under review by the IRS. The Company also is the subject of various state income tax examinations. With few exceptions, as of December 31, 2018, the Company is no longer subject to state examinations by tax authorities for years before 2012.

There were no material changes to the Company's methodology for accounting for unrecognized tax benefits during 2018.

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The following table summarizes the source and tax effects of temporary differences between financial reporting and tax bases of assets and liabilities:

	As of December 31,	
	2018	2017
	(Thousands)	
Deferred income taxes:		
Total deferred income tax assets	$(901,377)	$(1,112,514)
Total deferred income tax liabilities	2,724,758	3,002,476
Total net deferred income tax liabilities	1,823,381	1,889,962
Total deferred income tax liabilities (assets):		
Drilling and development costs expensed for income tax reporting	1,469,320	2,074,091
Tax depreciation in excess of book depreciation	904,030	644,590
Investment in Equitrans Midstream	(10,359)	—
Incentive compensation and deferred compensation plans	(24,682)	(43,822)
Net operating loss carryforwards	(429,983)	(564,180)
Alternative minimum tax credit carryforward	(308,727)	(435,190)
Federal tax credits	(37,710)	(50,341)
Unrealized (losses) gains	(28,096)	21,403
Interest disallowance limitation	(35,358)	—
Other	(26,462)	(18,981)
Total excluding valuation allowances	1,471,973	1,627,570
Valuation allowances	351,408	262,392
Total net deferred income tax liabilities	$1,823,381	$1,889,962

The net deferred tax liability decreased $66.6 million primarily due to the 2018 Divestitures, partially offset by an increase in tax depreciation in excess of book during the current year, utilization of Federal net operating losses, and refund of AMT credit carryovers.

As of December 31, 2018, the Company had a deferred tax asset of $32.9 million, net of valuation allowances of $22.8 million, related to tax benefits from federal NOL carryforwards expiring in 2037 to 2038. As of December 31, 2018, the Company had a deferred tax asset of $94.7 million, net of valuation allowances of $279.5 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2020 to 2037. On October 30, 2017, Pennsylvania enacted a change in the limitation on Pennsylvania NOL utilization to 35% of taxable income from 30% of taxable income for tax years beginning in 2018 and to 40% of taxable income for tax years beginning in 2019 and thereafter. However, due to the decrease in state apportionment rates, the Company will have less realizable NOL in future years. Additionally, the Tax Cuts and Jobs Act interest deduction limitation imposed for separate company state income tax reporting purposes resulted in a valuation allowance of $21.7 million. The Company also recorded a valuation allowance on the retained stake of Equitrans Midstream of $14 million for separate company state income tax reporting purposes. The Company reduced the valuation allowance on expected AMT credit refunds subject to federal sequestration to $13.3 million as a result of a change in estimate for the period ended December 31, 2018. The IRS announced in January 2019 that it was reversing its prior position that AMT refunds were subject to sequestration by the federal government at a rate equal to 6.2% of the refund. As a result, the Company will reverse this related valuation allowance in the first quarter of 2019. As of December 31, 2017, the Company had a deferred tax asset of $130 million, net of valuation allowances of $217.0 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2028 to 2038.

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10. Debt

	December 31, 2018			December 31, 2017		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
	(Thousands)					
8.13% Notes, due June 1, 2019	$700,000	$699,729	$712,663	$700,000	$698,918	$755,153
Floating Rate Notes due October 1, 2020	500,000	498,222	490,730	500,000	497,206	501,325
2.50% Notes due October 1, 2020	500,000	498,198	489,690	500,000	497,169	497,670
4.88% Notes, due November 15, 2021	750,000	746,245	762,555	750,000	744,920	801,953
3.00% Notes due October 1, 2022	750,000	743,972	712,980	750,000	742,364	743,550
7.75% debentures, due July 15, 2026	115,000	111,229	128,808	115,000	110,732	135,024
3.90% Notes due October 1, 2027	1,250,000	1,239,866	1,085,663	1,250,000	1,238,707	1,245,200
Medium-term notes:						
7.42% Series B, due 2023	10,000	10,000	10,666	10,000	10,000	11,433
7.6% Series C, due 2018	—	—	—	8,000	7,999	8,012
8.8% to 9.0% Series A, due 2020 through 2021	35,200	35,200	37,920	35,200	35,187	40,510
Note payable to EQM	114,720	114,720	121,752	119,127	119,127	133,001
Total debt	4,724,920	4,697,381	4,553,427	4,737,327	4,702,329	4,872,831
Less current portion of debt	704,661	704,390	717,609	12,407	12,406	12,932
Long-term debt	$4,020,259	$3,992,991	$3,835,818	$4,724,920	$4,689,923	$4,859,899

(a) For the note payable to EQM, the principal value represents the carrying value. For all other debt, the carrying value represents principal value less unamortized debt issuance costs and debt discounts.

(b) For the note payable to EQM, fair value is measured using Level 3 inputs, as described below. For all other debt, fair value is measured using Level 2 inputs.

2017 Notes. In October 2017, the Company completed the public offering (the 2017 Notes Offering) of $500 million aggregate principal amount of Floating Rate Notes due 2020 (the Floating Rate Notes), $500 million aggregate principal amount of 2.50% Senior Notes due 2020, $750 million aggregate principal amount of 3.00% Senior Notes due 2022 and $1,250 million aggregate principal amount of 3.90% Senior Notes due 2027. The Company received net proceeds from the 2017 Notes Offering of approximately $2,974.2 million, which the Company used, together with other cash on hand and borrowings under the Company’s $2.5 billion credit facility, to fund the cash portion of the consideration for and expenses related to the Rice Merger and related transactions including the repayment of certain indebtedness of Rice and its subsidiaries, to redeem or repay $700 million of the Company's Senior Notes due in 2018 and for other general corporate purposes. As a result of redeeming or repaying $700 million of Company's Senior Notes due in 2018, the Company recorded loss on debt extinguishment of $12.6 million, which included the make whole call premiums and the write-off of unamortized deferred financing costs.

The indentures governing the Company’s long-term indebtedness contain certain restrictive financial and operating covenants, including covenants that restrict, among other things, the Company’s ability to incur, as applicable, indebtedness, incur liens, enter into sale and leaseback transactions, complete acquisitions, merge, sell assets and perform certain other corporate actions. The covenants do not contain a rating trigger. Therefore, a change in the Company’s debt rating would not trigger a default under the indentures governing the indebtedness.

Aggregate maturities of Senior Notes are $700.0 million in 2019, $1,011.2 million in 2020, $774.0 million in 2021, $750.0 million in 2022, $10.0 million in 2023 and $1,365.0 million in 2024 and thereafter.

Note Payable to EQM. In April 2015, EQM acquired a preferred interest in EQT Energy Supply, LLC (EES). In October 2016, the operating agreement of EES was amended and the accounting for the preferred interest in EES converted to a note payable. Prior to the Separation and Distribution, the note payable to EQM was eliminated in consolidation. The fair value of the note payable to EQM is a Level 3 fair value measurement which is estimated using an income approach model utilizing a market-based discount rate. Principal amounts due are $4.7 million in 2019, $5.0 million in 2020, $5.2 million in 2021, $5.5 million in 2022, $5.8 million in 2023 and $88.5 million in 2024 and thereafter.

$2.5 Billion Facility. The Company has a $2.5 billion revolving credit facility that expires in July 2022. The Company may request two one-year extensions of the expiration date, the approval of which is subject to satisfaction of certain conditions. Subject to certain terms and conditions, the Company may, on a one-time basis, request that the lenders' commitments be increased to an aggregate of up to $3.0 billion. Each lender in the facility may decide if it will increase its commitment. The credit facility may be used for working capital, capital expenditures, share repurchases and any other lawful corporate purposes. The credit facility is underwritten by a syndicate of 19 financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company.

Under the terms of the credit facility, the Company may obtain base rate loans or Eurodollar rate loans denominated in U.S. dollars. Base rate loans bear interest at a base rate plus a margin based on the Company's then current credit ratings. Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Company's then current credit ratings.

The Company is not required to maintain compensating bank balances. The Company's debt issuer credit ratings, as determined by S&P, Moody's or Fitch Ratings Service (Fitch) on its non-credit-enhanced, senior unsecured long-term debt, determine the level of fees associated with the credit facility in addition to the interest rate charged by the counterparties on any amounts borrowed against the credit facility; the lower the Company's debt credit rating, the higher the level of fees and borrowing rate.

The Company had $0.8 billion and $1.3 billion of borrowings and zero and $159.4 million letters of credit outstanding under its credit facility as of December 31, 2018 and 2017, respectively. The Company incurred commitment fees averaging approximately 20, 20 and 23 basis points for the years ended December 31, 2018, 2017 and 2016, respectively, to maintain credit availability under its credit facility.

During 2018 and 2017, the maximum amounts of outstanding borrowings at any time under the credit facility were $1.6 billion and $1.4 billion, respectively, the average daily balances were approximately $854 million and $191 million, respectively, and interest was incurred at weighted average annual interest rates of 3.4% and 2.8%, respectively. The Company had no borrowings or letters of credit outstanding under its revolving credit facility at any time during the year ended December 31, 2016.

The Company's credit facility contains various provisions that, if not complied with, could result in termination of the credit facility, require early payment of amounts outstanding or similar actions. The most significant covenants and events of default under the credit facility relate to maintenance of a debt-to-total capitalization ratio and limitations on transactions with affiliates. The credit facility contains financial covenants that require a total debt-to-total capitalization ratio no greater than 65%. The calculation of this ratio excludes the effects of accumulated OCI. As of December 31, 2018, the Company was in compliance with all debt provisions and covenants.

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11. Changes in Accumulated Other Comprehensive Income (Loss) by Component

The following tables explain the changes in accumulated OCI by component for the three years ended December 31, 2018, 2017, and 2016.

Accumulated OCI (loss), net of tax	Natural gas cash flow hedges, net of tax		Interest rate cash flow hedges, net of tax		Pension and other post-retirement benefits liability adjustment, net of tax		Distribution of Equitrans Midstream Corporation	Accumulated OCI (loss), net of tax
	(Thousands)							
As of December 31, 2015	$64,762		$(843)		$(17,541)		$ —	$ 46,378
(Gains) losses reclassified from accumulated OCI, net of tax	(55,155)	(a)	144	(a)	10,675	(b)	—	(44,336)
As of December 31, 2016	$9,607		$(699)		$(6,866)		$ —	$ 2,042
(Gains) losses reclassified from accumulated OCI, net of tax	(4,982)	(a)	144	(a)	338	(b)	—	(4,500)
As of December 31, 2017	$4,625		$(555)		$(6,528)		$ —	$ (2,458)
(Gains) losses reclassified from accumulated OCI, net of tax	(4,625)	(a)	168	(a)	606	(b)	903	(2,948)
As of December 31, 2018	$—		$(387)		$(5,922)		$ 903	$ (5,406)

(a) Gains (losses) reclassified from accumulated OCI, net of tax related to natural gas cash flow hedges were reclassified into operating revenues. Losses from accumulated OCI, net of tax related to interest rate cash flow hedges were reclassified into interest expense.

(b) This accumulated OCI reclassification is attributable to the net actuarial loss and net prior service cost related to the Company's defined benefit pension plans and other post-retirement benefit plans. See Note 1 for additional information.

12. Common Stock and Treasury Stock

Common Stock

At December 31, 2018, shares of EQT's authorized and unissued common stock were reserved as follows:

	(Thousands)
Possible future acquisitions	20,457
Stock compensation plans	12,813
Total	33,270

In conjunction with the closing of the Rice Merger, the Company issued approximately 91 million shares of common stock on November 13, 2017.

On February 19, 2016, the Company entered into an Underwriting Agreement with Goldman, Sachs & Co. (Goldman) under which the Company sold to Goldman 6,500,000 shares of common stock at a price to the public of $58.50 per share (the February Offering). On February 22, 2016, Goldman exercised its option within the Underwriting Agreement to purchase an additional 975,000 shares of common stock on the same terms. The February Offering closed on February 24, 2016, and the Company received net proceeds of approximately $430.4 million, after deducting underwriting discounts and commissions and offering expenses. The Company used the net proceeds from the February Offering for general corporate purposes.

On May 2, 2016, the Company entered into an Underwriting Agreement with Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC, as representatives of the several underwriters named in the Underwriting Agreement (the Underwriters), under which the Company sold to the Underwriters 10,500,000 shares of common stock at a price to the public of $67.00 per share (the May Offering). On May 3, 2016, the Underwriters exercised their option within the Underwriting Agreement to purchase an additional 1,575,000 shares of common stock on the same terms. The May Offering closed on May 6, 2016, and the Company received net proceeds of approximately $795.6 million after deducting underwriting discounts and commissions and offering expenses. The Company used a portion of the net proceeds from the May Offering to fund the acquisitions discussed in Note 7 and the remainder for general corporate purposes.

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During 2018, the Company repurchased 10,646,382 shares at an average price of $50.62, which includes $0.02 for commission, pursuant to the Company's previously announced share repurchase programs. This exhausted the Company's share repurchase authorization under such programs.

Treasury Stock

Effective as of December 31, 2015, the Company transferred 17.0 million shares of treasury stock from issued to authorized but unissued shares. Additionally, during the year ended December 31, 2015, the Company funded 291,919 shares of treasury stock into a rabbi trust for the 2005 Directors’ Deferred Compensation Plan and the 1999 Directors' Deferred Compensation Plan. As of December 31, 2017, there were 253,145 shares of treasury stock in the rabbi trust. During 2018, the Company unfunded the rabbi trust and the treasury shares were transferred from authorized but unissued to unissued. No shares of treasury stock were held in the rabbi trust as of December 31, 2018.

13. Share-Based Compensation Plans

Share-based compensation expense recorded by the Company was as follows:

	Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
2014 Executive Performance Incentive Program	$—	$—	$9,494
2015 Executive Performance Incentive Program	—	5,348	12,456
2016 Incentive Performance Share Unit Program	6,863	13,077	7,166
2017 Incentive Performance Share Unit Program	2,467	5,038	—
2018 Incentive Performance Share Unit Program	4,742	—	—
2015 EQT Value Driver Award Program	—	—	3,174
2016 EQT Value Driver Performance Share Unit Award Program	—	3,341	15,694
2017 EQT Value Driver Performance Share Unit Award Program	584	10,822	—
2018 EQT Value Driver Performance Share Unit Award Program	8,224	—	—
Restricted stock awards	14,503	87,104	9,407
Non-qualified stock options	2,757	2,626	3,119
Other programs, including non-employee director awards	3,014	1,005	5,459
Less: Discontinued operations	(18,250)	(15,595)	(18,631)
Total share-based compensation expense	$24,904	$112,766	$47,338

In connection with the Separation, the Company transferred obligations related to share-based compensation awards outstanding to Equitrans Midstream. To preserve the aggregate fair value of awards held prior to the Separation, as measured immediately before and immediately after the Separation, each holder of share-based compensation awards generally received an adjusted award consisting of both a stock-based compensation award denominated in the Company equity and a stock-based compensation award denominated in Equitrans Midstream equity. These awards were adjusted in accordance with the basket method, resulting in participants retaining one unit of the existing Company incentive award while receiving an additional 0.80 units of an Equitrans Midstream-based award and includes awards that will be share-settled and awards expected to be satisfied in cash, which are treated as liability awards.

The Company recognizes compensation cost related to unvested awards held by it's employees, regardless of who settles the obligation. In accordance with the Employee Matters Agreement, the Company will be obligated to settle all outstanding share-based compensation awards denominated in the Company’s equity, regardless of whether the holders are employees of the Company or Equitrans Midstream at the vesting date. Likewise, Equitrans Midstream will be obligated to settle all of the outstanding share-based compensation awards denominated in its equity at the vesting date regardless of whether the holders are employees of Equitrans Midstream or the Company. Changes in performance and number of outstanding awards can impact the ultimate amount of these obligations. Share counts for awards discussed herein represent outstanding shares to be remitted by the Company to its employees and employees of Equitrans Midstream pursuant to the Employee Matters Agreement. When an award has graduated vesting, the Company records expense equal to the vesting percentage on the vesting date.

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The Company typically uses treasury stock to fund awards paid in stock, but the awards may be funded by stock acquired by the Company in the open market or from any other person, issued directly by the Company or any combination of the foregoing.

Cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2018, 2017 and 2016 was $1.9 million, $0.2 million and $5.0 million, respectively. During the years ended December 31, 2018, 2017 and 2016, share-based payment arrangements paid in stock generated tax benefits of $13.4 million, $58.9 million and $22.2 million, respectively.

Executive Performance Incentive Programs - Equity & Liability

The Management Development and Compensation Committee of the Company's Board of Directors (the Compensation Committee) has adopted:

- the 2014 Executive Performance Incentive Plan (2014 Incentive PSU Program) under the 2009 LTIP;
- the 2015 Executive Performance Incentive Plan (2015 Incentive PSU Program) under the 2014 Long-Term Incentive Plan (2014 LTIP);
- the 2016 Incentive Performance Share Unit Program (2016 Incentive PSU Program) under the 2014 LTIP;
- the 2017 Incentive Performance Share Unit Program (2017 Incentive PSU Program) under the 2014 LTIP; and
- the 2018 Incentive Performance Share Unit Program (2018 Incentive PSU Program) under the 2014 LITP.

The 2014 Incentive PSU Program, the 2015 Incentive PSU Program, the 2016 Incentive PSU Program, the 2017 Incentive PSU Program and the 2018 Incentive PSU Program are collectively referred to as the Incentive PSU Programs. The 2014 Incentive PSU Program, the 2015 Incentive PSU Program and the 2016 Incentive PSU Program granted equity awards. The 2017 Incentive PSU Program and the 2018 Incentive PSU Program granted both equity and liability awards.

The Incentive PSU Programs were established to provide long-term incentive opportunities to key employees to further align their interests with those of the Company’s shareholders and with the strategic objectives of the Company. The performance period for each of the awards under the Incentive PSU Programs is 36 months, with vesting occurring upon payment following the expiration of the performance period.

Executive Performance Incentive Program awards granted in years 2014 - 2017 were earned based upon:

- the level of total shareholder return relative to a predefined peer group; and
- the cumulative total sales volume growth, in each case, over the performance period.

Beginning with the 2018 Incentive PSU Program, awards granted are earned based upon:

- the level of total shareholder return relative to a predefined peer group;
- the level of operating and development cost improvement; and
- return on capital employed.

For the years ending December 31, 2019 and 2020, the 2018 Incentive PSU Program awards will be earned based on new performance goals to be established by the Compensation Committee, subject to continued employment through the payment date.

The payout factor varies between zero and 300% of the number of outstanding units contingent upon the performance metrics listed above. The Company recorded the 2014 Incentive PSU Program, the 2015 Incentive PSU Program, the 2016 Incentive PSU Program and the portion of the 2017 Incentive PSU Program and the 2018 Incentive PSU Program to be settled in stock as equity awards using a grant date fair value determined through a Monte Carlo simulation which projected the share price for the Company and its peers at the ending point of the performance period. The 2017 Incentive PSU Program and the 2018 Incentive PSU Program also included awards to be settled in cash which are recorded at fair value as of the measurement date determined through a Monte Carlo simulation which projected the share price for the Company and its peers at the ending point of the performance period. The expected share prices were generated using each company's annual volatility for the expected term and the commensurate three-year risk-free rate shown in the chart below for equity awards, one-year risk free rate shown in chart below for the 2017 Incentive PSU Program liability award, and two-year risk free rate shown in chart below for the 2018 Incentive PSU Program liability award. As the Incentive PSU Programs include a performance condition that affects the number of shares that will ultimately vest, the Monte Carlo simulation computed either the grant date fair value for equity awards or the measurement date fair value for liability awards for each possible performance condition outcome on the grant date for equity awards or the measurement date for liability awards. The Company reevaluates the then-probable outcome at the end of each reporting period to record expense at the probable outcome grant date fair value or measurement date fair value, as applicable. The vesting of the units under each Incentive PSU Program occurs upon payment after the end of the performance period. More detailed information about each award is set forth in the table below:

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Incentive PSU Program	Settled In	Accounting Treatment	Fair Value[(a)]	Risk Free Rate	Vested/Payment Date	Awards Paid	Value (Millions)	Unvested/Expected Payment Date	Awards Outstanding as of December 31, 2018[(b)]
2014	Stock	Equity	$189.68	0.78%	February 2017	238,060	$ 45.2	N/A	N/A
2015	Stock	Equity	$141.11	1.10%	February 2018	274,767	$ 38.8	N/A	N/A
2016[(c)]	Stock	Equity	$109.30	1.31%	N/A	N/A	N/A	First Quarter of 2019	384,101
2017[(d)]	Stock	Equity	$120.60	1.47%	N/A	N/A	N/A	First Quarter of 2020	44,573
2017[(e)]	Cash	Liability	$59.90	2.61%	N/A	N/A	N/A	First Quarter of 2020	105,018
2018[(f)]	Stock	Equity	$76.53	1.97%	N/A	N/A	N/A	First Quarter of 2021	107,340
2018[(g)]	Cash	Liability	$33.30	2.46%	N/A	N/A	N/A	First Quarter of 2021	124,820

(a) Information shown for the valuation of the liability plans is as of December 31, 2018.

(b) Represents the number of outstanding units as of December 31, 2018 adjusted for forfeitures. The 2016, 2017, and 2018 Incentive PSU Programs to be settled in stock include 130,393, 7,020, and 34,640 shares, respectively, for Equitrans Midstream employees that will be settled by the Company under the Employee Matters Agreement. The 2017 and 2018 Incentive PSU Programs to be settled in cash include 43,134 and 57,240 shares, respectively, for Equitrans Midstream employees that will be settled by the Company under the Employee Matters Agreement.

(c) As of January 1, 2018, a total of 447,145 units were outstanding under the 2016 Incentive PSU Program. Adjusting for 63,044 forfeitures, there were 384,101 outstanding units as of December 31, 2018.

(d) As of January 1, 2018, a total of 79,070 units were outstanding under the 2017 Incentive PSU Program - Equity. Adjusting for 34,497 forfeitures, there were 44,573 outstanding units as of December 31, 2018.

(e) As of January 1, 2018, a total of 117,530 units were outstanding under the 2017 Incentive PSU Program - Liability. Adjusting for 12,512 forfeitures, there were 105,018 total outstanding units as of December 31, 2018.

(f) A total of 172,350 units were granted under the 2018 Incentive PSU Program - Equity in 2018 and no additional units may be granted. Adjusting for 65,010 forfeitures, there were 107,340 outstanding units as of December 31, 2018.

(g) A total of 142,890 units were granted under the 2018 Incentive PSU Program - Liability in 2018 and no additional units may be granted. Adjusting for 18,070 forfeitures, there were 124,820 total outstanding units as of December 31, 2018.

The following table sets forth the total compensation costs capitalized related to each of the Incentive PSU Programs:

Award	For the Years Ended December 31, 2018	2017	2016
	(Millions)		
2014 Incentive PSU Program	$—	$—	$4.2
2015 Incentive PSU Program	—	2.2	4.9
2016 Incentive PSU Program	2.1	4.4	3.3
2017 Incentive PSU Program (liability only)	1.0	1.7	—
2018 Incentive PSU Program (liability only)	0.6	—	—

As of December 31, 2018, $0.6 million, $2.0 million, $1.1 million and $3.0 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2017 Incentive PSU Program - Equity, the 2017 Incentive PSU Program - Liability, the 2018 Incentive PSU Program - Equity and 2018 Incentive PSU Program - Liability, respectively, was expected to be recognized over the remainder of the performance periods.

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Fair value is estimated using a Monte Carlo simulation valuation method with the following weighted average assumptions:

	For Incentive PSU Programs Issued During the Years Ended December 31,						
	2018	2018	2017	2017	2016	2015	2014
Accounting Treatment	Liability[a]	Equity	Liability[a]	Equity	Equity	Equity	Equity
Risk-free rate	2.46%	1.97%	2.61%	1.47%	1.31%	1.10%	0.78%
Dividend Yield[b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Volatility factor	35.70%	32.60%	41.17%	32.30%	28.43%	27.45%	31.38%
Expected term	2 years	3 years	1 year	3 years	3 years	3 years	3 years

(a) Information shown for the valuation of the liability plans is as of December 31, 2018.

(b) Dividends paid from the beginning of the performance period will be cumulatively added as additional shares of common stock.

Value Driver Award Programs

The Compensation Committee has also adopted:

- the 2015 Value Driver Award Program (2015 EQT VDPSU Program) under the 2014 LTIP;
- the 2016 Value Driver Performance Share Unit Award Program (2016 EQT VDPSU Program) under the 2014 LTIP;
- the 2017 Value Driver Performance Share Unit Award Program (2017 EQT VDPSU Program) under the 2014 LTIP; and
- the 2018 Value Driver Performance Share Unit Award Program (2018 EQT VDPSU Program) under the 2014 LTIP.

The 2015 EQT VDPSU Program, the 2016 EQT VDPSU Program, the 2017 EQT VDPSU Program and the 2018 EQT VDPSU Program are collectively referred to as the VDPSU Programs.

The VDPSU Programs were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company. Under each VDPSU Program, 50% of the awards confirmed vest upon payment following the first anniversary of the grant date; the remaining 50% of the awards confirmed vest upon payment following the second anniversary of the grant date subject to continued service through such date. Due to the graded vesting of each award under the VDPSU Programs, the Company recognized compensation cost over the requisite service period for each separately vesting tranche of the award as though each award was, in substance, multiple awards. The payments are contingent upon adjusted earnings before interest, income taxes, depreciation and amortization performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the respective one-year periods. More detailed information about each award is set forth in the table below:

EQT VDPSU Program	Settled In	Accounting Treatment	Fair Value per Unit[a]	Vested/Payment Date	Number of awards (including accrued dividends) or cash (Millions) paid	Unvested/Expected Payment Date	Awards Outstanding (including accrued dividends) as of December 31, 2018[d]
2015	Stock	Equity	$75.70	February 2016	222,751	N/A	N/A
			$75.70	February 2017	208,567	N/A	N/A
2016[b]	Cash	Liability	$65.40	February 2017	$21.3	N/A	N/A
			$56.92	February 2018	$16.8	N/A	N/A
			$56.92	February 2018	$14.0	N/A	N/A
2017	Cash	Liability					

			$ 18.89	N/A	N/A	Second tranche first quarter of 2019	214,384
2018[c]	Cash	Liability	$ 18.89	N/A	N/A	First tranche first quarter of 2019	256,803
			N/A	N/A	N/A	Second tranche first quarter of 2020	257,254

(a) For equity awards, the fair value per unit is equal to the Company's closing common stock price on the business day prior to the grant date. For liability awards, the fair value per unit is equal to the Company's common stock price on the measurement date.

(b) In addition to the $21.3 million in awards paid in February 2017, $0.2 million in awards were paid in 2017 in accordance with employee separation agreements.

(c) The total liability recorded for the 2018 EQT VDPSU Program was $1.7 million as of December 31, 2018.

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(d) The 2017 and 2018 EQT VDPSU Programs include 95,452 and 135,345 awards, respectively, for Equitrans Midstream employees that will be settled by the Company under the Employee Matters Agreement.

The following table sets forth the total compensation costs capitalized related to each of the VDPSU Programs:

Award	For the Years Ended December 31,		
	2018	2017	2016
	(Millions)		
2015 EQT VDPSU Program	$ —	$ —	$ 4.1
2016 EQT VDPSU Program	—	7.0	16.3
2017 EQT VDPSU Program	0.1	10.3	—
2018 EQT VDPSU Program	3.3	—	—

Restricted Stock Awards - Equity

The Company granted 145,540, 85,350 and 158,360 restricted stock equity awards during the years ended December 31, 2018, 2017 and 2016, respectively, to key employees of the Company. The restricted stock granted will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued service through such date. The weighted average fair value of these restricted stock grants, based on the grant date fair value of the Company’s common stock, was approximately $54.33, $63.00 and $75.00 for the years ended December 31, 2018, 2017 and 2016, respectively.

The Company granted 7,900 restricted stock equity awards during the year ended December 31, 2016 to its then Chief Financial Officer. The restricted shares granted were fully vested at the end of the one-year period commencing on the date of grant. The fair value of this restricted stock grant, based on the Company's closing common stock price on the grant date, was $63.33 per share.

In conjunction with the closing of the Rice Merger, the Company converted Rice restricted stock equity awards and performance share equity awards to 2,290,234 Company restricted stock equity awards on November 13, 2017. Employees who were terminated on the closing date were immediately vested in their Company awards and received Merger Consideration cash of $5.30 per Rice share. Company awards of those employees who continued employment with the Company under a transition agreement will vest upon the earlier of (i) the end of the vesting period set forth in the original award agreement or (ii) the end of such employee's employment period set forth in his/her transition agreement, in both cases subject to continued service through such date. Company awards of those employees who continued employment with the Company on an at will basis will vest in accordance with the vesting period set forth in the original award agreement, assuming continued service through such date. The fair value of these restricted stock grants, based on the grant date fair value of the Company’s common stock, was approximately $65.18.

The total fair value of restricted stock awards vested during the years ended December 31, 2018, 2017 and 2016 was $39.8 million, $123.0 million and $5.1 million, respectively. The $123.0 million in 2017 includes $13.0 million for the cash payment for the Merger Consideration of $5.30 per Rice share.

As of December 31, 2018, $2.5 million of unrecognized compensation cost related to nonvested restricted stock equity awards was expected to be recognized over a remaining weighted average vesting term of approximately 1.3 years.

A summary of restricted stock equity award activity as of December 31, 2018, and changes during the year then ended, is presented below:

Restricted Stock	Non-	Weighted	Aggregate

	Vested Shares[a]	Average Fair Value	Fair Value
Outstanding at January 1, 2018	729,500	$ 66.86	$48,776,872
Granted	145,540	54.33	7,906,734
Vested	(596,888)	66.75	(39,843,286)
Forfeited	(85,370)	62.26	(5,314,727)
Outstanding at December 31, 2018	192,782	$ 59.79	$11,525,593

(a) Non-vested shares outstanding at December 31, 2018 included 107,422 shares for Equitrans Midstream employees that will be settled by the Company under the Employee Matters Agreement.

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Restricted Stock Unit Awards - Liability

During the years ended December 31, 2018, 2017, and 2016, respectively, the Company granted 373,750, 292,400, and 148,860 restricted stock unit liability awards that will be paid in cash to key employees of the Company. Adjusting for forfeitures, there were 639,780 awards outstanding as of December 31, 2018. Because these awards are liability awards, the Company records compensation expense based upon the fair value of the awards as remeasured at the end of each reporting period. The restricted units granted will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued service through such date. The total liability recorded for these restricted units was $6.9 million, $8.8 million, and $2.7 million as of December 31, 2018, 2017, and 2016, respectively.

Non-Qualified Stock Options

The fair value of the Company's option grants was estimated at the dates of grant using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the years ended December 31, 2018, 2017 and 2016. The risk-free rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the date of grant. The dividend yield is based on the dividend yield of the Company's common stock at the time of grant. Expected volatilities are based on historical volatility of the Company's common stock. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	For the Years Ended December 31,		
	2018	2017[(a)]	2016[(a)]
Risk-free interest rate	2.25 %	1.95 %	1.67 %
Dividend yield	0.20 %	0.18 %	0.16 %
Volatility factor	26.46 %	27.45 %	28.59 %
Expected term	5 years	5 years	5 years
Number of Options Granted	287,800	153,700	228,500
Weighted Average Grant Date Fair Value	$15.39	$17.47	$15.10
Total Intrinsic Value of Options Exercised (millions)	$—	$1.7	$3.5

(a) There were two grant dates for the 2017 and 2016 options. Amounts represent weighted average.

As of December 31, 2018, $0.4 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2019.

A summary of option activity as of December 31, 2018, and changes during the year then ended, is presented below:

Non-qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2018	1,129,200	$ 63.42		
Granted	287,800	56.92		
Exercised	—	—		
Forfeited	(215,100)	58.14		
Converted awards granted as a result of Separation	573,529	31.23		
Expired	—	—		
Outstanding at December 31, 2018	1,775,429	$ 32.43	5.57 years	$ —
Exercisable at December 31, 2018	1,533,452	$ 32.88	5.22 years	$ —

Non-employee Directors' Share-Based Awards

The Company has historically granted to EQT non-employee directors share-based awards which vest upon grant of the awards. The share-based awards will be paid in cash or Company common stock following the directors' termination of service on the Company's Board of Directors. Awards that will be paid in cash are accounted for as liability awards and as such compensation expense is recorded based upon the fair value of the awards as remeasured at the end of each reporting period. Awards that will be settled in Company common stock are accounted for as equity awards and as such the Company recorded compensation expense for the fair value of the awards at the grant date fair value. A total of 267,906 non-employee director share-based awards including

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accrued dividends were outstanding as of December 31, 2018. A total of 50,979, 26,090 and 37,620 share-based awards were granted to non-employee directors during the years ended December 31, 2018, 2017 and 2016, respectively. The weighted average fair value of these grants, based on the Company's closing common stock price on the business day prior to the grant date, was $52.65, $65.35 and $52.13 for the years ended December 31, 2018, 2017 and 2016, respectively.

2019 Value Driver Performance Share Unit Award Program and 2019 Incentive Performance Share Unit Program

Effective in 2019, the Compensation Committee adopted the 2019 EQT Value Driver Performance Share Unit Award Program (2019 EQT VDPSU Program) and the 2019 Incentive Performance Share Unit Program (2019 Incentive PSU Program) under the 2014 LTIP. The 2019 EQT VDPSU Program and 2019 Incentive PSU Program were established to align the interests of key employees with the interests of shareholders and customers and the strategic objectives of the Company.

A total of 614,680 units were granted under the 2019 EQT VDPSU Program. Fifty percent of the units confirmed under the 2019 EQT VDPSU Program will vest upon payment following the first anniversary of the grant date; the remaining 50% of the confirmed units under the 2019 EQT VDPSU Program will vest upon payment following the second anniversary of the grant date. The payout will vary between zero and 300% of the number of outstanding units contingent upon adjusted 2019 earnings before interest, income taxes, depreciation and amortization performance as compared to the Company's annual business plan and individual, business unit and Company value driver performance over the period January 1, 2019 through December 31, 2019. If earned, the 2019 EQT VDPSU Program units are expected to be paid in cash.

A total of 642,920 units were granted under the 2019 Incentive PSU Program. The vesting of the units under the 2019 Incentive PSU Program will occur upon payment after December 31, 2021 (the end of the three-year performance period). The payout will vary between zero and 300% of the number of outstanding units contingent upon a combination of the level of total shareholder return relative to a predefined peer group, the level of operating and development cost improvement, and return on capital employed over the period January 1, 2019 through December 31, 2021. If earned, 402,220 of the 2019 Incentive PSU Program units are expected to be distributed in Company common stock and 240,700 of the 2019 Incentive PSU Program units are expected to be paid in cash.

2019 Stock Options

Effective January 1, 2019, the Compensation Committee granted 669,200 non-qualified stock options to key employees of the Company. The 2019 options are ten-year options, with an exercise price of $18.89, and are subject to three-year cliff vesting.

2019 Restricted Stock and Restricted Stock Unit Awards

Effective January 1, 2019, the Compensation Committee granted 201,130 restricted stock equity and 427,900 restricted stock unit liability awards. The restricted stock equity awards and restricted stock unit liability awards will be fully vested at the end of the three-year period commencing with the date of grant, assuming continued employment.

14. Concentrations of Credit Risk

Revenues and related accounts receivable from the Company's operations are generated primarily from the sale of produced natural gas, NGLs and crude oil to marketers, utility and industrial customers located mainly in the Appalachian Basin and in markets available through the Company's current transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States as well as Canada. The Company also contracts with certain processors to market a portion of NGLs on behalf of the Company. No single customer accounted for more than 10% of the Company's revenues for 2018, 2017 and 2016.

Approximately 64% and 59% of the Company’s accounts receivable balance as of December 31, 2018 and 2017, respectively, represented amounts due from marketers. The Company manages the credit risk of sales to marketers by limiting its dealings to those marketers that meet the Company’s criteria for credit and liquidity strength and by regularly monitoring these accounts. The Company may require letters of credit, guarantees, performance bonds or other credit enhancements from a marketer for that marketer to meet the Company’s credit criteria. As a result, the Company did not experience any significant defaults on sales of natural gas to marketers during the years ended December 31, 2018, 2017 or 2016.

The Company is exposed to credit loss in the event of nonperformance by counterparties to derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. The Company’s OTC derivative instruments are primarily with financial institutions and, thus, are subject to events that would impact those companies individually as well as the financial industry as a whole.

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The Company utilizes various processes and analyses to monitor and evaluate its credit risk exposures. These include monitoring current market conditions, counterparty credit fundamentals and credit default swap rates. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, the Company enters into transactions primarily with financial counterparties that are of investment grade, enters into netting agreements whenever possible and may obtain collateral or other security.

As of December 31, 2018, the Company was not in default under any derivative contracts and had no knowledge of default by any counterparty to its derivative contracts. During the year ended December 31, 2018, the Company made no adjustments to the fair value of derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in the Company's established fair value procedure. The Company monitors market conditions that may impact the fair value of derivative contracts reported in the Consolidated Balance Sheets.

15. Commitments and Contingencies

The Company has commitments for demand charges under existing long-term contracts and binding precedent agreements with various pipelines as well as commitments for processing capacity. Future payments for these items as of December 31, 2018 totaled \$23.5 billion (2019 - \$1.3 billion, 2020 - \$1.7 billion, 2021 - \$1.8 billion, 2022 - \$1.8 billion, 2023 - \$1.7 billion and thereafter - \$15.2 billion). The Company also has commitments to purchase equipment and frac sand to be used as a proppant in its hydraulic fracturing operations. As of December 31, 2018, future commitments under these contracts due in 2019 totaled \$74.0 million.

Operating lease rentals for drilling contractors, office locations and warehouse buildings, as well as a limited amount of equipment, amounted to approximately \$117.4 million in 2018, \$60.8 million in 2017 and \$44.1 million in 2016. As of December 31, 2018, future lease payments under non-cancelable operating leases inclusive of drilling equipment and services obligations totaled \$109.9 million (2019 - \$70.3 million, 2020 - \$8.4 million, 2021 - \$8.4 million, 2022 – \$8.4 million, 2023 - \$8.4 million and thereafter - \$6.0 million).

If any credit rating agency downgrades the Company's ratings, particularly below investment grade, the Company may be required to provide additional credit assurances in support of commercial agreements, such as pipeline capacity contracts, the amount of which may be substantial.

On January 16, 2013, several royalty owners who had entered into leases with EQT Production Company, a subsidiary of the Company, filed a gas royalty class action lawsuit in the Circuit Court of Doddridge County, West Virginia. The suit alleged that EQT Production Company and a number of related companies failed to pay royalties on the fair value of the gas produced from the leases and took improper post-production deductions from the royalties paid. The plaintiffs sought more than \$100 million (according to expert reports) in compensatory damages, punitive damages, and other relief. On May 31, 2013, the defendants removed the lawsuit to federal court. On September 6, 2017, the district court granted the plaintiffs' motion to certify the class and granted the plaintiffs' motion for summary judgment, finding that EQT Production Company and its marketing affiliate EQT Energy, LLC are alter egos of one another. The defendants sought immediate appeal of the class certification. On November 30, 2017, the Court of Appeals declined the request for an immediate review. On February 13, 2019, the Company announced that it and the other defendants reached a tentative settlement agreement with the class representatives. Pursuant to the terms of the proposed settlement agreement, the Company agreed to pay \$53.5 million into a settlement fund that will be established to disburse payments to class participants, and stop taking future post production deductions on leases that are determined by the Court to not permit deductions. The Company and the class representatives also agreed that future royalty payments will be based on a clearly defined index pricing methodology. The tentative settlement agreement is subject to Court approval and achieving a threshold minimum percentage of participation by the class members. Each class member will have the opportunity to opt out of the settlement. If approved, the settlement will resolve the royalty claims for the class period, which spans from 2009 through 2017. The Company recorded a litigation reserve liability of $53.5 million in other current liabilities in the Consolidated Balance Sheets as of December 31, 2018.

The Company is subject to various federal, state and local environmental and environmentally-related laws and regulations. These laws and regulations, which are constantly changing, can require expenditures for remediation and may in certain instances result in the assessment of fines. The Company has established procedures for ongoing evaluation of its operations to identify potential environmental exposures and to assure compliance with regulatory policies and procedures. The estimated costs associated with identified situations that require remedial action are accrued. Ongoing expenditures for compliance with environmental laws and regulations, including investments in plant and facilities to meet environmental requirements, have not been material. Management believes that any such required expenditures will not be significantly different in either their nature or amount in the future and does not know of any environmental liabilities that will have a material effect on the Company’s financial position,

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results of operations or liquidity. The Company has identified situations that require remedial action for which approximately $11.8 million is included in other liabilities and credits in the Consolidated Balance Sheets as of December 31, 2018.

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company accrues legal or other direct costs related to loss contingencies when actually incurred. The Company has established reserves it believes to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, the Company believes that the ultimate outcome of any matter currently pending against the Company will not materially affect the financial position, results of operations or liquidity of the Company.

16. Guarantees

In connection with the sale of its NORESCO domestic operations in December 2005, the Company agreed to maintain in place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that once the energy-efficiency construction was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a period of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately $76 million as of December 31, 2018, extending at a decreasing amount for approximately 10 years.

In connection with EQM's IPO in 2012, EQT guaranteed all payment obligations, up to a maximum of $50 million, due and payable to Equitrans, L.P. (Equitrans), a wholly owned subsidiary of EQM, by EQT Energy, LLC (EQT Energy), one of Equitrans's largest customers and a wholly owned subsidiary of EQT (the EQM IPO Guaranty). The EQM IPO Guaranty will terminate on November 30, 2023 unless terminated earlier by EQT upon 10 days written notice.

These guarantees are exempt from ASC Topic 460, Guarantees. The Company has determined that the likelihood it will be required to perform on these arrangements is remote and any potential payments are expected to be immaterial to the Company's financial position, results of operations and liquidity. As such, the Company has not recorded any liabilities in its Consolidated Balance Sheets related to these guarantees.

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17. Interim Financial Information (Unaudited)

The following quarterly summary of operating results reflects variations due to various factors including: the volatility of natural gas commodity prices, impairments, the Separation and Distribution, the impact of the Tax Cuts and Jobs Act and the inclusion of Rice operations beginning November 13, 2017. All prior periods presented have been recast to reflect the presentation of discontinued operations as described in Note 2.

	Three Months Ended			
	March 31	June 30	September 30	December 31
	(Thousands, except per share amounts)			
2018				
Total operating revenues	$1,312,036	$950,648	$1,050,046	$1,245,138
Operating (loss)	(1,950,332)	(114,650)	(147,451)	(570,691)
Amounts attributable to EQT Corporation:				
(Loss) from continuing operations	(1,578,533)	(76,978)	(127,347)	(598,062)
(Loss) income from discontinued operations, net of tax	(7,461)	94,784	87,654	(38,625)
Net (loss) income attributable to EQT Corporation	$(1,585,994)	$17,806	$(39,693)	$(636,687)
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
(Loss) from continuing operations	$(5.96)	$(0.29)	$(0.49)	$(2.35)
Income from discontinued operations	(0.03)	0.36	0.34	(0.15)
Net (loss) income	$(5.99)	$0.07	$(0.15)	$(2.50)
Diluted:				
(Loss) from continuing operations	$(5.96)	$(0.29)	$(0.49)	$(2.35)
Income from discontinued operations	(0.03)	0.36	0.34	(0.15)
Net (loss) income	$(5.99)	$0.07	$(0.15)	$(2.50)
2017				
Total operating revenues	$828,662	$631,101	$597,718	$1,033,539
Operating income (loss)	243,572	47,763	(6,380)	97,257
Amounts attributable to EQT Corporation:				
(Loss) income from continuing operations	113,190	3,387	(6,238)	1,276,690
Income from discontinued operations, net of tax	50,802	37,739	29,578	3,381
Net income attributable to EQT Corporation	$163,992	$41,126	$23,340	$1,280,071
Earnings per share of common stock attributable to EQT Corporation:				
Basic:				
(Loss) income from continuing operations	$0.66	$0.02	$(0.04)	$5.83
Income from discontinued operations	0.29	0.22	0.17	0.02
Net income	$0.95	$0.24	$0.13	$5.85
Diluted:				
(Loss) income from continuing operations	$0.66	$0.02	$(0.04)	$5.81
Income from discontinued operations	0.29	0.22	0.17	0.02
Net income	$0.95	$0.24	$0.13	$5.83

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18. Natural Gas Producing Activities (Unaudited)

The supplementary information summarized below presents the results of natural gas and oil activities in accordance with the successful efforts method of accounting for production activities.

Production Costs

The following tables present the total aggregate capitalized costs and the costs incurred relating to natural gas, NGLs and oil production activities (a):

	For the Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
At December 31:			
Capitalized Costs:			
Proved properties	$17,648,731	$18,920,855	$12,179,833
Unproved properties	4,166,048	5,016,299	1,698,826
Total capitalized costs	21,814,779	23,937,154	13,878,659
Accumulated depreciation and depletion	4,666,212	5,121,646	4,217,154
Net capitalized costs	$17,148,567	$18,815,508	$9,661,505

	For the Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
Costs incurred: (a)			
Property acquisition:			
Proved properties (b)	$77,099	$5,251,711	$403,314
Unproved properties (c)	198,854	3,310,995	880,545
Exploration (d)	1,708	15,505	6,047
Development	2,443,980	1,357,165	777,787
Geological and geophysical	—	—	—

(a) Amounts exclude capital expenditures for facilities and information technology.

(b) Amounts in 2018 include $5.2 million and $9.2 million for the purchase of Marcellus and Utica wells respectively, which includes the impact of measurement period adjustments for the 2017 acquisitions discussed in Note 3 and 7. Amounts in 2017 include $2,530.4 million and $1,192.0 million for the purchase of Marcellus wells and leases, respectively, acquired in the 2017 transactions discussed in Notes 3 and 7. The purchase of Marcellus leases includes measurement period adjustments to the 2016 acquisitions. Amounts in 2017 also include $1,228.6 million and $0.3 million for the purchase of Utica wells and leases, respectively, acquired in the 2017 transactions discussed in Notes 3 and 7. Amounts in 2016 include $256.2 million and $112.2 million for the purchase of Marcellus wells and leases, respectively, acquired in the 2016 transactions discussed in Note 7.

(c) Amounts in 2017 include $2,625.1 million and $0.5 million for the purchase of Marcellus leases and Utica leases, respectively, acquired in the 2017 transactions discussed in Notes 3 and 7. Amounts in 2016 include $770.4 million for the purchase of Marcellus leases acquired in the 2016 transactions discussed in Note 7.

(d) Amounts include capitalizable exploratory costs and exploration expense, excluding impairments.

Capitalized costs of unproved oil and gas properties are evaluated at least annually for recoverability on a prospective basis. Indicators of potential impairment include changes brought about by economic factors, potential shifts in business strategy employed by management and historical experience. The likelihood of an impairment of unproved oil and gas properties increases as the expiration of a lease term approaches if drilling activity has not commenced. If it is determined that the Company does not intend to drill on the property prior to expiration or does not have the intent and ability to extend, renew, trade, or sell the lease prior to expiration, an impairment expense is recorded. Expense for lease expirations that were not previously impaired are recorded as the leases expire. For the years ended December 31, 2018, 2017 and 2016, the Company recorded $279.7 million, $7.6 million and $15.7 million, respectively for lease impairments and expirations. The Company’s unproved properties had a net book value of $4,166.0 million and $5,016.3 million at December 31, 2018 and 2017, respectively.

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Results of Operations for Producing Activities

The following table presents the results of operations related to natural gas, NGLs and oil production:

	For the Years Ended December 31,		
	2018	2017	2016
	(Thousands)		
Revenues	$4,695,519	$2,651,318	$1,594,997
Transportation and processing	1,697,001	1,164,783	880,191
Production	195,775	181,349	174,170
Exploration	6,765	17,565	4,663
Depreciation and depletion	1,569,038	970,985	856,451
Impairment of long-lived assets	2,709,976	—	—
Lease impairments and expirations	279,708	7,552	15,686
Income tax (benefit) expense	(454,009)	121,359	(135,029)
Results of operations from producing activities (excluding corporate overhead)	$(1,308,735)	$187,725	$(201,135)

Reserve Information

The information presented below represents estimates of proved natural gas, NGLs and oil reserves prepared by Company engineers. The engineer primarily responsible for preparing the reserve report and the technical aspects of the reserves audit received a bachelor's degree in Chemical Engineering from the Pennsylvania State University and has 21 years of experience in the oil and gas industry. To ensure that the reserves are materially accurate, management reviews the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves; division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserve reconciliation between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas, NGLs and oil reserves are audited by the independent consulting firm of Ryder Scott Company, L.P. (Ryder Scott), which is hired by the Company's management. Since 1937, Ryder Scott has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally.

Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. There were no differences between the internally prepared and externally audited estimates. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred. In the course of its audit, Ryder Scott reviewed 100% of the total net natural gas, NGLs and oil proved reserves attributable to the Company's interests as of December 31, 2018. Ryder Scott conducted a detailed, well by well, audit of the Company's largest properties. This audit covered 81% of the Company's proved developed reserves. Ryder Scott's audit of the remaining 19% of the Company's proved developed properties consisted of an audit of aggregated groups not exceeding 200 wells per case for operated wells and 115 wells per case for non-operated wells. For undeveloped locations, the Company determined, and Ryder Scott reviewed and approved, the areas within the Company's acreage considered to be proven. Reserves were assigned and projected by the Company's reserve engineers for locations within these proven areas and approved by Ryder Scott based on analogous type curves and offset production information. The audit utilized the performance method and the analogy method. Where historical reserve or production data was definitive, the performance method, which extrapolates historical data, was utilized. In other cases the analogy method, which calculates reserves based on correlations to comparable surrounding wells, was utilized. All of the Company's proved reserves are located in the United States.

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	Years Ended December 31,		
	2018	2017	2016
	(Millions of Cubic Feet)		
Total - Natural Gas, Oil, and NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	21,445,667	13,508,407	9,976,597
Revision of previous estimates	(1,124,904)	(2,766,981)	(472,285)
Purchase of hydrocarbons in place	—	9,389,638	2,395,776
Sale of hydrocarbons in place	(1,748,557)	(2,646)	—
Extensions, discoveries and other additions	4,739,233	2,225,141	2,384,682
Production	(1,494,663)	(907,892)	(776,363)
End of year	21,816,776	21,445,667	13,508,407
Proved developed reserves:			
Beginning of year	11,297,956	6,842,958	6,279,557
End of year	11,550,161	11,297,956	6,842,958
Proved undeveloped reserves:			
Beginning of year	10,147,711	6,665,449	3,697,040
End of year	10,266,615	10,147,711	6,665,449

(a) Oil and NGLs were converted at the rate of one thousand Bbl equal to approximately 6 million cubic feet (MMcf).

	Years Ended December 31,		
	2018	2017	2016
	(Millions of Cubic Feet)		
Natural Gas			
Proved developed and undeveloped reserves:			
Beginning of year	19,830,236	12,331,867	9,110,311
Revision of previous estimates	(960,285)	(2,760,467)	(607,171)
Purchase of natural gas in place	—	8,890,145	2,288,166
Sale of natural gas in place	(1,331,391)	(1,210)	—
Extensions, discoveries and other additions	4,659,835	2,164,578	2,241,528
Production	(1,392,943)	(794,677)	(700,967)
End of year	20,805,452	19,830,236	12,331,867
Proved developed reserves:			
Beginning of year	10,152,543	6,074,958	5,652,989
End of year	10,887,953	10,152,543	6,074,958
Proved undeveloped reserves:			
Beginning of year	9,677,693	6,256,909	3,457,322
End of year	9,917,499	9,677,693	6,256,909

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	Years Ended December 31,		
	2018	2017	2016
	(Thousands of Bbls)		
Oil (a)			
Proved developed and undeveloped reserves:			
Beginning of year	10,731	6,395	5,900
Revision of previous estimates	6,217	5,103	1,159
Purchase of oil in place	—	355	3
Sale of oil in place	(10,447)	(139)	—
Extensions, discoveries and other additions	338	9	62
Production	(680)	(992)	(729)
End of year	6,159	10,731	6,395
Proved developed reserves:			
Beginning of year	10,731	6,395	5,900
End of year	3,489	10,731	6,395
Proved undeveloped reserves:			
Beginning of year	—	—	—
End of year	2,670	—	—

(a) One thousand Bbl equals approximately 6 million cubic feet (MMcf).

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of Bbls)		
NGLs (a)			
Proved developed and undeveloped reserves:			
Beginning of year	258,507	189,695	138,481
Revision of previous estimates	(33,653)	(6,189)	21,322
Purchase of NGLs in place	—	82,894	17,932
Sale of NGLs in place	(59,080)	(100)	—
Extensions, discoveries and other additions	12,895	10,084	23,797
Production	(16,274)	(17,877)	(11,837)
End of year	162,395	258,507	189,695
Proved developed reserves:			
Beginning of year	180,170	121,605	98,528
End of year	106,879	180,170	121,605
Proved undeveloped reserves:			
Beginning of year	78,337	68,090	39,953
End of year	55,516	78,337	68,090

(a) One thousand Bbl equals approximately 6 million cubic feet (MMcf).

2018 Changes in Reserves

- Transfer of 2,722 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 4,739 Bcfe, which exceeded the 2018 production of 1,495 Bcfe.

Increase of 315 Bcfe from proved developed reserves extensions from reservoirs underlying acreage not previously booked as proved in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields.

Increase of 886 Bcfe from proved undeveloped reserves extensions from acreage proved by drilling activity in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields.

Increase of 3,538 Bcfe from other proved undeveloped additions associated with acreage that was excluded from prior year proved reserves bookings, but subsequently became proved due to inclusion within the Company's five-year drilling plan.

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- Negative revisions of 1,273 Bcfe from proved undeveloped locations that are no longer expected to be developed within five years of initial booking as proved reserves, resulting from changes in the Company's future development plans to focus more heavily on developing the Company's core Pennsylvania assets.
- Upward revisions of 148 Bcfe primarily due to increased reserves from producing wells and improved commodity prices.
- The sale of hydrocarbons in place of 1,749 Bcfe is due to the 2018 Divestitures as described in Note 8.

2017 Changes in Reserves

- Transfer of 987 Bcfe of proved undeveloped reserves to proved developed reserves.
- Increase of 9,390 Bcfe associated with the acquisition of proved developed reserves (3,330 Bcfe) and proved undeveloped reserves (6,060 Bcfe) in the Company's Marcellus, Upper Devonian and Utica plays.
- Extensions, discoveries and other additions of 2,225 Bcfe, which exceeded the 2017 production of 908 Bcfe. Increase of 300 Bcfe from proved developed reserves extensions from reservoirs underlying acreage not previously booked as proved in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields. Increase of 893 Bcfe from proved undeveloped reserves extensions from acreage proved by drilling activity in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields. Increase of 1,032 Bcfe from other proved undeveloped additions associated with acreage that was excluded from prior year proved reserves bookings, but subsequently became proved due to inclusion within the Company's five-year drilling plan.
- Negative revisions of 3,522 Bcfe from proved undeveloped locations, primarily due to 3,074 Bcfe from locations that are no longer anticipated to be drilled within 5 years of booking as a result of acquiring new acreage. The acquired acreage presents opportunities to drill considerably longer laterals, realize operational efficiencies and improve overall returns.
- Upward revisions of 477 Bcfe from proved developed locations, primarily due to increased reserves from producing wells.
- Upward revisions of 278 Bcfe associated with previously booked locations whose economic lives had been extended due to improved commodity prices.

2016 Changes in Reserves

- Transfer of 647 Bcfe of proved undeveloped reserves to proved developed reserves.
- Increase of 2,396 Bcfe associated with the acquisition of proved developed reserves (320 Bcfe) and proved undeveloped reserves (2,076 Bcfe) in the Company's Marcellus and Upper Devonian plays.
- Extensions, discoveries and other additions of 2,385 Bcfe, which exceeded the 2016 production of 776 Bcfe. Increase of 341 Bcfe from proved developed reserves extensions from reservoirs underlying acreage not previously booked as proved in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields. Increase of 673 Bcfe from proved undeveloped reserves extensions from acreage proved by drilling activity in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields. Increase of 1,371 Bcfe from other proved undeveloped additions associated with acreage that was excluded from prior year proved reserves bookings, but subsequently became proved due to inclusion within the Company's five-year drilling plan.
- Negative revisions of 509 Bcfe from proved undeveloped locations, primarily due to 389 Bcfe from economic locations that the Company no longer expects to develop within 5 years of booking, along with the removal of locations that are no longer economic as determined in accordance with Securities and Exchange Commission (SEC) pricing requirements.
- Upward revisions of 68 Bcfe from proved developed locations, primarily due to increased reserves from producing wells.
-

Negative revisions of 31 Bcfe associated with previously booked locations whose economic lives had been shortened due to reduced commodity prices.

Standard Measure of Discounted Future Cash Flow

Management cautions that the standard measure of discounted future cash flows should not be viewed as an indication of the fair market value of natural gas and oil producing properties, nor of the future cash flows expected to be generated therefrom. The information presented does not give recognition to future changes in estimated reserves, selling prices or costs and has been discounted at a rate of 10%. The estimated future net cash flows from natural gas and oil reserves as of December 31, 2018 and 2017 includes the impact of the Tax Cuts and Jobs Act, which resulted in a lower federal income tax rate than as of December 31, 2016.

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Estimated future net cash flows from natural gas and oil reserves are as follows at December 31:

	2018	2017	2016
	(Thousands)		
Future cash inflows (a)	$60,603,624	$51,423,920	$24,011,281
Future production costs (b)	(20,463,567)	(18,379,892)	(14,864,126)
Future development costs	(5,854,503)	(5,637,676)	(3,778,698)
Future income tax expenses	(6,823,621)	(5,811,125)	(1,753,067)
Future net cash flow	27,461,933	21,595,227	3,615,390
10% annual discount for estimated timing of cash flows	(15,850,035)	(12,593,293)	(2,626,636)
Standardized measure of discounted future net cash flows	$11,611,898	$9,001,934	$988,754

(a) The majority of the Company's production is sold through liquid trading points on interstate pipelines. For 2018, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2018 of $65.56 per Bbl of oil (first day of each month closing price for West Texas Intermediate (WTI)) less regional adjustments, $2.888 per Dth for Columbia Gas Transmission Corp., $2.568 per Dth for Dominion Transmission, Inc., $2.587 per Dth for Texas Eastern Transmission Corp., $2.320 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company and $2.939 per Dth for the Rockies Express Pipeline Zone 3. For 2018, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2018 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $21.93 per Bbl of NGLs for certain West Virginia Marcellus reserves and $33.89 per Bbl of NGLs per Bbl for Ohio Utica reserves.

The majority of the Company's production is sold through liquid trading points on interstate pipelines. For 2017, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2017 of $51.34 per Bbl of oil (first day of each month closing price for West Texas Intermediate (WTI)) less regional adjustments, $2.801 per Dth for Columbia Gas Transmission Corp., $2.100 per Dth for Dominion Transmission, Inc., $2.914 per Dth for the East Tennessee Natural Gas Pipeline, $2.058 per Dth for Texas Eastern Transmission Corp., $1.995 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company, $2.321 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company, $2.665 per Dth for Waha, and $2.840 per Dth for the Rockies Express Pipeline Zone 3. For 2017, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2017 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $23.07 per Bbl of NGLs from certain West Virginia Marcellus reserves, $31.11 per Bbl of NGLs from certain Kentucky reserves, $29.47 per Bbl for Ohio Utica reserves, and $27.93 per Bbl for Permian reserves.

The majority of the Company's production is sold through liquid trading points on interstate pipelines. For 2016, the reserves were computed using unweighted arithmetic averages of the closing prices on the first day of each month during 2016 of $42.75 per Bbl of oil (first day of each month closing price for WTI) less regional adjustments, $2.342 per Dth for Columbia Gas Transmission Corp., $1.348 per Dth for Dominion Transmission, Inc., $2.334 per Dth for the East Tennessee Natural Gas Pipeline, $1.325 per Dth for Texas Eastern Transmission Corp., $1.305 per Dth for the Tennessee, zone 4-300 Leg of Tennessee Gas Pipeline Company, $1.862 per Dth for the Tennessee LA 500 Leg of Tennessee Gas Pipeline Company, $2.343 per Dth for Waha, and $2.402 per Dth for the Rockies Express Pipeline Zone 3. For 2016, NGL pricing using arithmetic averages of the closing prices on the first day of each month during 2016 for NGL components and adjusted using the regional component makeup of produced NGLs resulted in prices of $13.87 per Bbl of NGLs from certain West Virginia Marcellus reserves, $17.27 per Bbl of NGLs from certain Kentucky reserves, $14.71 per Bbl for Ohio Utica reserves, and $18.91 per Bbl for Permian reserves.

(b) Includes approximately $883 million, $1,400 million and $790 million as of December 31, 2018, 2017 and 2016 respectively for future plugging and abandonment costs.

Holding production and development costs constant, a change in price of $0.20 per Dth for natural gas, $10 per barrel for oil and $10 per barrel for NGLs would result in a change in the December 31, 2018 discounted future net cash flows before income taxes of the Company’s proved reserves of approximately $1.9 billion, $34.2 million and $665.7 million, respectively.

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Summary of changes in the standardized measure of discounted future net cash flows for the years ended December 31:

	2018	2017	2016
	(Thousands)		
Sales and transfers of natural gas and oil produced – net	$(2,802,742)	$(1,305,186)	$(540,636)
Net changes in prices, production and development costs	2,949,606	2,236,183	(1,129,026)
Extensions, discoveries and improved recovery, less related costs	1,616,653	1,269,712	590,885
Development costs incurred	1,630,506	712,635	402,891
Purchase of minerals in place – net	—	5,357,921	592,078
Sale of minerals in place – net	(849,162)	(284)	—
Revisions of previous quantity estimates	(811,576)	(297,437)	(60,959)
Accretion of discount	834,026	115,437	122,674
Net change in income taxes	(289,549)	(1,477,603)	(91,823)
Timing and other (a)	332,202	1,401,802	125,116
Net increase (decrease)	2,609,964	8,013,180	11,200
Beginning of year	9,001,934	988,754	977,554
End of year	$11,611,898	$9,001,934	$988,754

(a) Increase in 2017 primarily driven by timing changes to the Company’s development plan as a result of the Rice Merger.

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

Not Applicable.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including the Company's Principal Executive Officer and Principal Financial Officer, an evaluation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)), was conducted 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.

Management's Report on Internal Control over Financial Reporting

The management of EQT is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act). EQT's internal control system is designed to provide reasonable assurance to the Company's management and Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. All internal control systems, no matter how well designed, have inherent limitations. Accordingly, even effective controls can provide only reasonable assurance with respect to financial statement preparation and presentation.

EQT's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2018.

Ernst & Young LLP (Ernst & Young), the independent registered public accounting firm that audited the Company's Consolidated Financial Statements, has issued an attestation report on the Company's internal control over financial reporting. Ernst & Young's attestation report on the Company's internal control over financial reporting appears in Part II, Item 8 of this Annual Report on Form 10-K and is incorporated by reference herein.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the fourth quarter of 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

On February 12, 2019, the Management Development and Compensation Committee of the Board of Directors of the Company approved an amendment to certain confidentiality, non-solicitation and non-competition agreements (the Non-Competition Agreements), including those with the Company's named executive officers. The amendment permits the applicable executive to elect out of the executive alternative work arrangement contemplated by his or her Non-Competition Agreement, which, in the absence of an election, applies following certain qualifying terminations of employment. If an executive elects out of the executive alternative work arrangement, in consideration for such election, the non-competition covenant set forth in his or her Non-Competition Agreement will be extended for an additional three months beyond the period specified therein.

Additional information regarding the executive alternative work arrangement is included in the Company's annual proxy statement, dated April 27, 2018.

The form of amendment to the Non-Competition Agreements is filed as Exhibit 10.22 to this Annual Report on Form 10-K. The foregoing summary is qualified by reference thereto.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated herein by reference from the Company's definitive proxy statement relating to the 2019 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2018:

- Information required by Item 401 of Regulation S-K with respect to directors is incorporated herein by reference from the sections captioned "Item No. 1 – Election of Directors," and "Corporate Governance and Board Matters" in the Company's definitive proxy statement;
- Information required by Item 405 of Regulation S-K with respect to compliance with Section 16(a) of the Exchange Act is incorporated herein by reference from the section captioned "Equity Ownership – Section 16(a) Beneficial Ownership Reporting Compliance" in the Company's definitive proxy statement;
- Information required by Item 407(d)(4) of Regulation S-K with respect to disclosure of the existence of the Company's separately-designated standing Audit Committee and the identification of the members of the Audit Committee is incorporated herein by reference from the section captioned "Corporate Governance and Board Matters – Board Meetings and Committees – Audit Committee" in the Company's definitive proxy statement; and
- Information required by Item 407(d)(5) of Regulation S-K with respect to disclosure of the Company's audit committee financial expert is incorporated herein by reference from the section captioned "Corporate Governance and Board Matters – Board Meetings and Committees – Audit Committee" in the Company's definitive proxy statement.

Information required by Item 401 of Regulation S-K with respect to executive officers is included after Item 4 at the end of Part I of this Annual Report on Form 10-K under the caption "Executive Officers of the Registrant (as of February 14, 2019)," and is incorporated herein by reference.

The Company has adopted a code of business conduct and ethics applicable to all directors and employees, including the principal executive officer, principal financial officer and principal accounting officer. The code of business conduct and ethics is posted on the Company's website http://www.eqt.com (accessible by clicking on the "Investors" link on the main page followed by the "Corporate Governance" link and the "Charters and Documents" link), and a printed copy will be delivered free of charge on request by writing to the corporate secretary at EQT Corporation, c/o Corporate Secretary, 625 Liberty Avenue, Suite 1700, Pittsburgh, Pennsylvania 15222. The Company intends to satisfy the disclosure requirement regarding certain amendments to, or waivers from, provisions of its code of business conduct and ethics by posting such information on the Company's website.

Item 11. Executive Compensation

The following information is incorporated herein by reference from the Company's definitive proxy statement relating to the 2019 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2018:

- Information required by Item 402 of Regulation S-K with respect to named executive officer and director compensation is incorporated herein by reference from the sections captioned "Executive Compensation - Compensation Discussion and Analysis," "Executive Compensation - Compensation Tables," "Executive Compensation - Compensation Policies and Practices and Risk Management," and "Directors' Compensation" in the Company's definitive proxy statement; and

Information required by paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K with respect to certain matters related to the Management Development and Compensation Committee of the Company's Board of Directors is incorporated herein by reference from the sections captioned “Corporate Governance and Board Matters - Compensation Committee Interlocks and Insider Participation” and “Executive Compensation - Report of the Management Development and Compensation Committee” in the Company’s definitive proxy statement.

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

Information required by Item 403 of Regulation S-K with respect to stock ownership of significant shareholders, directors and executive officers is incorporated herein by reference to the sections captioned “Equity Ownership - Stock Ownership of Significant Shareholders” and “Equity Ownership - Equity Ownership of Directors and Executive Officers” in the Company’s definitive proxy statement relating to the 2019 annual meeting of shareholders, which will be filed with the SEC within 120 days after the close of the Company’s fiscal year ended December 31, 2018.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2018 with respect to shares of the Company’s common stock that may be issued under the Company’s existing equity compensation plans, including the 2014 Long-Term Incentive Plan (2014 LTIP), the 2009 Long-Term Incentive Plan (2009 LTIP), the 1999 Non-Employee Directors’ Stock Incentive Plan (1999 NEDSIP), the 2005 Directors’ Deferred Compensation Plan (2005 DDCP), the 1999 Directors’ Deferred Compensation Plan (1999 DDCP), the 2008 Employee Stock Purchase Plan (2008 ESPP), and the 2014 Rice Energy Inc. 2014 Long-Term Incentive Plan (Rice LTIP):

Plan Category	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 (B)		Number Of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected In Column A) (C)	
Equity Compensation Plans Approved by Shareholders [1]	4,636,432	[2]	$ 32.43	[3]	2,714,195	[4]
Equity Compensation Plans Not Approved by Shareholders [5]	33,865	[6]	N/A		5,023,753	
Total	4,670,297		$ 32.43		7,737,948	

(1) Consists of the 2014 LTIP, the 2009 LTIP, the 1999 NEDSIP and the 2008 ESPP. Effective as of April 30, 2014, in connection with the adoption of the 2014 LTIP, the Company ceased making new grants under the 2009 LTIP. Effective as of April 22, 2009, in connection with the adoption of the 2009 LTIP, the Company ceased making new grants under the 1999 NEDSIP. The 2009 LTIP and the 1999 NEDSIP remain effective solely for the purpose of issuing shares upon the exercise or payout of awards outstanding under such plans on April 30, 2014 (for the 2009 LTIP) and April 22, 2009 (for the 1999 NEDSIP).

(2) Consists of (i) 819,115 shares subject to outstanding stock options under the 2014 LTIP; (ii) 2,694,090 shares subject to outstanding performance awards under the 2014 LTIP, inclusive of dividend reinvestments thereon (counted at a 3X multiple assuming maximum performance is achieved under the awards (representing 1,614,294 target and confirmed awards and dividend reinvestments thereon)), (iii) 127,217 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon, (iv) 956,314 shares subject to outstanding stock options under the 2009 LTIP; (v) 35,101 shares subject to outstanding directors' deferred stock units under the 2009 LTIP, inclusive of dividend reinvestments thereon, and (vi) 4,595 shares subject to outstanding directors' deferred stock units under the 1999 NEDSIP, inclusive of dividend reinvestments thereon.

(3) The weighted-average exercise price is calculated solely based upon outstanding stock options under the 2014 LTIP and the 2009 LTIP and excludes deferred stock units under the 2014 LTIP, the 2009 LTIP and the 1999 NEDSIP and performance awards under the 2014 LTIP and 2009 LTIP. The weighted average remaining term of the stock options was 5.57 years as of December 31, 2018.

(4) Consists of (i) 2,185,717 shares available for future issuance under the 2014 LTIP, (ii) 29,924 shares under the 2009 LTIP and (iii) 498,554 shares available for future issuance under the 2008 ESPP. As of December 31, 2018, no shares were subject to purchase under the 2008 ESPP.

(5) Consists of the 2005 DDCP, the 1999 DDCP and the Rice LTIP each of which are described below.

(6) Consists of (i) 33,865 shares invested in the EQT Common Stock Fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP and the 1999 DDCP as of December 31, 2018.

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2005 Directors' Deferred Compensation Plan

The 2005 DDCP was adopted by the Management Development and Compensation Committee, effective January 1, 2005. Neither the original adoption of the plan nor its amendments required approval by the Company's shareholders. The plan allows non-employee directors to defer all or a portion of their directors' fees and retainers. Amounts deferred are payable on or following retirement from the Board unless an early payment is authorized after the director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers, the deferred stock units granted to directors on or after January 1, 2005 under the 1999 NEDSIP, the 2009 LTIP and the 2014 LTIP are administered under this plan.

1999 Directors' Deferred Compensation Plan

The 1999 DDCP was suspended as of December 31, 2004. The plan continues to operate for the sole purpose of administering vested amounts deferred under the plan on or prior to December 31, 2004. Deferred amounts are generally payable on or following retirement from the Board, but may be payable earlier if an early payment is authorized after a director suffers an unforeseeable financial emergency. In addition to deferred directors' fees and retainers and a one-time grant of deferred shares in 1999 resulting from the curtailment of the directors' retirement plan, the deferred stock units granted to directors and vested prior to January 1, 2005 under the 1999 NEDSIP are administered under this plan.

Rice Energy Inc. 2014 Long-Term Incentive Plan

The board of directors of Rice adopted the Rice Energy Inc. 2014 Long-Term Incentive Plan (as amended and restated effective as of May 9, 2014), which was assumed by the Company in connection with the Rice Merger for employees and non-employee directors of the Company and any of its affiliates. The Company may issue long-term equity based awards under the plan. Employees and non-employee directors of the Company or any affiliate, including subsidiaries, are eligible to receive awards under the plan.

The aggregate number of shares that may be issued under the plan is 6,475,000 shares, subject to proportionate adjustment in the event of stock splits, recapitalizations, mergers and similar events. Shares subject to awards that (i) expire or are canceled, forfeited, exchanged, settled in cash, or otherwise terminated; and (ii) are delivered by the participant or withheld from an award to satisfy tax withholding requirements, and delivered or withheld to pay the exercise price of an option, will again be available for awards under the plan.

The plan is administered by the Committee, except to the extent the Board elects to administer the plan.

The plan authorizes the granting of awards in any of the following forms: performance awards, restricted stock units, dividend equivalent rights, market-priced options to purchase stock, stock appreciation rights, other share-based awards that are denominated or payable in, valued in whole or in part by reference to, or otherwise based on stock, and cash-based awards.

The Board may amend, alter, suspend, discontinue or terminate the plan at any time, except that no amendment may be made without the approval of the Company's shareholders if shareholder approval is required by any federal or state law or regulation or by the rules of any exchange on which the stock may then be listed, or if the amendment, alteration or other change increases the number of shares available under the plan, or if the Board in its discretion determines that obtaining such shareholder approval is for any reason advisable.

Shares to be delivered pursuant to awards under the plan may be shares made available from (i) authorized but unissued shares of stock, (ii) treasury stock, or (iii) previously issued shares of stock reacquired by the Company, including shares purchased on the open market.

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

Information required by Items 404 and 407(a) of Regulation S-K with respect to director independence and related person transactions is incorporated herein by reference to the section captioned "Corporate Governance and Board Matters – Independence and Related Person Transactions" in the Company's definitive proxy statement relating to the 2019 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company's fiscal year ended December 31, 2018.

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Item 14. Principal Accounting Fees and Services

Information required by Item 9(e) of Schedule 14A is incorporated herein by reference to the section captioned “Item No. 3 – Ratification of Appointment of Independent Registered Public Accounting Firm” in the Company’s definitive proxy statement relating to the 2019 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of the Company’s fiscal year ended December 31, 2018.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report

1. All Financial Statements

2. Financial Statement Schedule

Schedule II - Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 2018

EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2018

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	(Deductions) Additions Charged to Costs and Expenses	Additions Charged to Other Accounts	Deductions	Balance at End of Period
	(Thousands)				
Valuation allowance for deferred tax assets:					

2018	$262,392	$98,311	$—	$(9,295)	$351,408
2017	$201,422	$70,063	$—	$(9,093)	$262,392
2016	$156,084	$24,706	$21,536	$(904)	$201,422

All other schedules are omitted since the subject matter thereof is either not present or is not present in amounts sufficient to require submission of the schedules.

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3. Exhibits

Exhibits	Description	Method of Filing
2.01	Separation and Distribution Agreement, dated as of November 12, 2018, by and among the Company, Equitrans Midstream Corporation and, solely for certain limited purposes therein, EQT Production Company.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on November 13, 2018.
2.02	Transition Services Agreement, dated as of November 12, 2018, by and between the Company and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 2.2 to Form 8-K (#001-3551) filed on November 13, 2018.
2.03	Tax Matters Agreement, dated as of November 12, 2018, by and between the Company and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 2.3 to Form 8-K (#001-3551) filed on November 13, 2018.
2.04	Employee Matters Agreement, dated as of November 12, 2018, by and between the Company and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 2.4 to Form 8-K (#001-3551) filed on November 13, 2018.
2.05	Shareholder and Registration Rights Agreement, dated as of November 12, 2018, by and between the Company and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on November 13, 2018.
3.01	Restated Articles of Incorporation of the Company (amended through November 13, 2017).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on November 14, 2017.
3.02	Amended and Restated Bylaws of the Company (amended through November 13, 2017).	Incorporated herein by reference to Exhibit 3.3 to Form 8-K (#001-3551) filed on November 14, 2017.
4.01(a)	Indenture dated as of April 1, 1983 between the Company and Pittsburgh National Bank, as Trustee.	Incorporated herein by reference to Exhibit 4.01(a) to Form 10-K (#001-3551) for the year ended December 31, 2007.
4.01(b)	Instrument appointing Bankers Trust Company as successor trustee to Pittsburgh National Bank.	Incorporated herein by reference to Exhibit 4.01(b) to Form 10-K (#001-3551) for the year ended December 31, 1998.
4.01(c)	Resolution adopted August 19, 1991 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 27, establishing the terms and provisions of the Series A Medium-Term Notes.	Incorporated herein by reference to Exhibit 4.01(g) to Form 10-K (#001-3551) for the year ended December 31, 1996.
4.01(d)	Resolutions adopted July 6, 1992 and February 19, 1993 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 through 8, establishing the terms and provisions of the Series B Medium-Term Notes.	Incorporated herein by reference to Exhibit 4.01(h) to Form 10-K (#001-3551) for the year ended December 31, 1997.
4.01(e)	Resolution adopted July 14, 1994 by the Ad Hoc Finance Committee of the Board of Directors of the Company and Addenda Nos. 1 and 2, establishing the terms and provisions of the Series C Medium-Term Notes.	Incorporated herein by reference to Exhibit 4.01(i) to Form 10-K (#001-3551) for the year ended December 31, 1995.
4.01(f)	Second Supplemental Indenture dated as of June 30, 2008 between the Company and Deutsche Bank Trust Company Americas, as Trustee, pursuant to which the Company assumed the obligations of Equitable	Incorporated herein by reference to Exhibit 4.01(g) to Form 8-K (#001-3551) filed on July 1, 2008.

	Resources, Inc. under the related Indenture.	
4.02(a)	Indenture dated as of July 1, 1996 between the Company and The Bank of New York, as successor to Bank of Montreal Trust Company, as Trustee.	Incorporated herein by reference to Exhibit 4.01(a) to Form S-4 Registration Statement (#333-103178) filed on February 13, 2003.
4.02(b)	Resolutions adopted January 18 and July 18, 1996 by the Board of Directors of the Company and Resolution adopted July 18, 1996 by the Executive Committee of the Board of Directors of the Company, establishing the terms and provisions of the 7.75% Debentures issued July 29, 1996.	Incorporated herein by reference to Exhibit 4.01(j) to Form 10-K (#001-3551) for the year ended December 31, 1996.

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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Exhibits	Description	Method of Filing
4.02(c)	First Supplemental Indenture dated as of June 30, 2008 between the Company and The Bank of New York, as Trustee, pursuant to which the Company assumed the obligations of Equitable Resources, Inc. under the related Indenture.	Incorporated herein by reference to Exhibit 4.02(f) to Form 8-K (#001-3551) filed on July 1, 2008.
4.03(a)	Indenture dated as of March 18, 2008 between the Company and The Bank of New York, as Trustee.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on March 18, 2008.
4.03(b)	Third Supplemental Indenture dated as of May 15, 2009 between the Company and The Bank of New York, as Trustee, pursuant to which the 8.125% Senior Notes due 2019 were issued.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on May 15, 2009.
4.03(c)	Fourth Supplemental Indenture dated as of November 7, 2011 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 4.875% Senior Notes due 2021 were issued.	Incorporated herein by reference to Exhibit 4.2 to Form 8-K (#001-3551) filed on November 7, 2011.
4.03(d)	Fifth Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the Floating Rate Notes due 2020 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on October 4, 2017.
4.03(e)	Sixth Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 2.500% Senior Notes due 2020 were issued.	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on October 4, 2017.
4.03(f)	Seventh Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 3.000% Senior Notes due 2022 were issued.	Incorporated herein by reference to Exhibit 4.7 to Form 8-K (#001-3551) filed on October 4, 2017.
4.03(g)	Eighth Supplemental Indenture dated as of October 4, 2017 between the Company and The Bank of New York Mellon, as Trustee, pursuant to which the 3.900% Senior Notes due 2027 were issued.	Incorporated herein by reference to Exhibit 4.9 to Form 8-K (#001-3551) filed on October 4, 2017.
*10.01(a)	2009 Long-Term Incentive Plan (as amended and restated through July 11, 2012).	Incorporated herein by reference to Exhibit 10.2 to Form 10-Q (#001-3551) for the quarter ended June 30, 2012.
*10.01(b)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (pre-2012 grants).	Incorporated herein by reference to Exhibit 10.01(q) to Form 10-K (#001-3551) for the year ended December 31, 2010.
*10.01(c)	Form of Amendment to Stock Option Award Agreements.	Incorporated herein by reference to Exhibit 10.3 to Form 10-Q (#001-3551) for the quarter ended June 30, 2011.
*10.01(d)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2012 grants).	Incorporated herein by reference to Exhibit 10.02(n) to Form 10-K (#001-3551) for the year ended December 31, 2011.
*10.01(e)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013 grants).	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-K (#001-3551) for the year ended December 31, 2012.
*10.01(f)		

Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2013 grants).	Incorporated herein by reference to Exhibit 10.02(t) to Form 10-K (#001-3551) for the year ended December 31, 2012.

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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Exhibits	Description	Method of Filing
*10.01(g)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 and 2014 grants).	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K (#001-3551) for the year ended December 31, 2012.
*10.01(h)	Form of Participant Award Agreement (Stock Option) under 2009 Long-Term Incentive Plan (2014 grants).	Incorporated herein by reference to Exhibit 10.02(v) to Form 10-K (#001-3551) for the year ended December 31, 2013.
*10.02(a)	2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 1, 2014.
*10.02(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.02(c)	2015 Executive Performance Incentive Program.	Incorporated herein by reference to Exhibit 10.03(d) to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.02(d)	Form of Participant Award Agreement under 2015 Executive Performance Incentive Program.	Incorporated herein by reference to Exhibit 10.03(e) to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.02(e)	Amendment to 2015 Executive Performance Incentive Program.	Incorporated herein by reference to Exhibit 10.03(f) to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.02(f)	2016 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(g) to Form 10-K (#001-3551) for the year ended December 31, 2015.
*10.02(g)	Form of Participant Award Agreement under 2016 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(h) to Form 10-K (#001-3551) for the year ended December 31, 2015.
*10.02(h)	2016 Restricted Stock Award Agreement (Standard) for Robert J. McNally.	Incorporated herein by reference to Exhibit 10.03 to Form 10-Q (#001-3551) for the quarter ended March 31, 2016.
*10.02(i)	Form of 2016 Value Driver Performance Award Agreement.	Filed herewith as Exhibit 10.02(i).
*10.02(j)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (pre-2017 grants).	Incorporated herein by reference to Exhibit 10.03(c) to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.02(k)	2017 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(l) to Form 10-K (#001-3551) for the year ended December 31, 2016.
*10.02(l)	Form of Participant Award Agreement under 2017 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(m) to Form 10-K (#001-3551) for the year ended December 31, 2016.
*10.02(m)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2017 grants).	Incorporated herein by reference to Exhibit 10.02(k) to Form 10-K (#001-3551) for the year ended December 31, 2016.
*10.02(n)	Form of 2017 Value Driver Performance Award Agreement.	Filed herewith as Exhibit 10.02(n).
*10.02(o)	Form of Restricted Stock Unit Award Agreement (Standard).	Filed herewith as Exhibit 10.02(o).
*10.02(p)	Form of Restricted Stock Award Agreement under 2014	

	Long-Term Incentive Plan (pre-2018 grants).	Incorporated herein by reference to Exhibit 10.02(d) to Form 10-K (#001-3551) for the year ended December 31, 2016.
*10.02(q)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2018 grants).	Incorporated herein by reference to Exhibit 10.02(r) to Form 10-K (#001-3551) for the year ended December 31, 2017.

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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Exhibits	Description	Method of Filing
*10.02(r)	Form of Restricted Stock Award Agreement (Standard) under 2014 Long-Term Incentive Plan (2018 grants).	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K (#001-3551) for the year ended December 31, 2017.
*10.02(s)	Form of 2018 Value Driver Performance Award Agreement.	Filed herewith as Exhibit 10.02(s).
*10.02(t)	Form of 2018 Restricted Stock Units Award Agreement (Standard) under 2014 Long-Term Incentive Plan (2018 grants).	Filed herewith as Exhibit 10.02(t).
*10.02(u)	2018 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(t) to Form 10-K (#001-3551) for the year ended December 31, 2017.
*10.02(v)	Form of Participant Award Agreement under 2018 Incentive Performance Share Unit Program (executive officers).	Incorporated herein by reference to Exhibit 10.02(u) to Form 10-K (#001-3551) for the year ended December 31, 2017.
*10.02(w)	Form of Participant Award Agreement under 2018 Incentive Performance Share Unit Program.	Filed herewith as Exhibit 10.02(w).
*10.02(x)	Form of 2018 Strategic Implementation Performance Share Units Award Agreement.	Filed herewith as Exhibit 10.02(x).
*10.02(y)	Form of 2018 Restricted Stock Unit Award Agreement (Transaction).	Filed herewith as Exhibit 10.02(y).
*10.02(z)	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2019 grants).	Filed herewith as Exhibit 10.02(z).
*10.02(aa)	Form of Restricted Stock Award Agreement (Standard) under 2014 Long-Term Incentive Plan (2019 grants).	Filed herewith as Exhibit 10.02(aa).
*10.02(bb)	2019 Incentive Performance Share Unit Program.	Filed herewith as Exhibit 10.02(bb).
*10.02(cc)	Form of Participant Award Agreement under 2019 Incentive Performance Share Unit Program.	Filed herewith as Exhibit 10.02(cc).
*10.03(a)	Rice Energy Inc. 2014 Long-Term Incentive Plan (as amended and restated May 9, 2014).	Incorporated herein by reference to Exhibit 10.3 to Rice Energy Inc.'s Form 10-Q (#001-36273) for the quarter ended June 30, 2014.
*10.03(b)	Form of Restricted Stock Unit Agreement (Directors) for Rice Energy Inc.	Incorporated herein by reference to Exhibit 10.19 to Rice Energy Inc.'s Amendment No. 2 to Form S-1 Registration Statement (#333-192894) filed on January 8, 2014.
*10.04(a)	1999 Non-Employee Directors’ Stock Incentive Plan (as amended and restated December 3, 2008).	Incorporated herein by reference to Exhibit 10.02(a) to Form 10-K (#001-3551) for the year ended December 31, 2008.
*10.04(b)	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 1999 Non-Employee Directors’ Stock Incentive Plan.	Incorporated herein by reference to Exhibit 10.04(c) to Form 10-K (#001-3551) for the year ended December 31, 2006.
*10.05	2016 Executive Short-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on April 21, 2016.

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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Exhibits	Description	Method of Filing
*10.06	2018 Short-Term Incentive Plan.	Filed herewith as Exhibit 10.06.
*10.07	2006 Payroll Deduction and Contribution Program (as amended and restated July 7, 2015).	Incorporated herein by reference to Exhibit 10.06 to Form 10-Q (#001-3551) for the quarter ended June 30, 2015.
*10.08(a)	1999 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014).	Incorporated herein by reference to Exhibit 10.08 to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.08(b)	Amendment to 1999 Directors' Deferred Compensation Plan (as amended October 2, 2018).	Incorporated herein by reference to Exhibit 10.4 to Form 10-Q (#001-3551) for the quarter ended September 30, 2018.
*10.09(a)	2005 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014).	Incorporated herein by reference to Exhibit 10.09 to Form 10-K (#001-3551) for the year ended December 31, 2014.
*10.09(b)	Amendment to 2005 Directors' Deferred Compensation Plan (as amended October 2, 2018).	Incorporated herein by reference to Exhibit 10.5 to Form 10-Q (#001-3551) for the quarter ended September 30, 2018.
*10.10	Form of Indemnification Agreement between the Company and each executive officer and each outside director.	Incorporated herein by reference to Exhibit 10.18 to Form 10-K (#001-3551) for the year ended December 31, 2008.
10.11	Second Amended and Restated Credit Agreement, dated as of July 31, 2017, among the Company, PNC Bank, National Association, as Administrative Agent, Swing Line Lender and an L/C Issuer and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on August 3, 2017.
*10.12	Separation and Release Agreement, dated as of November 13, 2017, among the Company, EQT RE, LLC and Daniel J. Rice IV.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on November 17, 2017.
*10.13(a)	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of March 10, 2016, between the Company and Robert J. McNally.	Incorporated herein by reference to Exhibit 10.02 to Form 10-Q (#001-3551) for the quarter ended March 31, 2016.
*10.13(b)	Amendment of Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of November 12, 2018, by and among the Company, Equitrans Midstream Corporation and Robert J. McNally.	Filed herewith as Exhibit 10.13(b).
*10.14	Second Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of November 13, 2018, by and between the Company and Jimmi Sue Smith.	Incorporated herein by reference to Exhibit 10.2 to Form 8-K (#001-3551) filed on November 13, 2018.
*10.15	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of November 13, 2018, by and between the Company and Erin R. Centofanti.	Filed herewith as Exhibit 10.15.
*10.16(a)	Second Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of March 1, 2017, by and	Filed herewith as Exhibit 10.16(a).

	between the Company and Donald M. Jenkins.	
*10.16(b)	Amendment of Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of November 12, 2018, by and among the Company, Equitrans Midstream Corporation and Donald M. Jenkins.	Filed herewith as Exhibit 10.16(b).

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

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Exhibits	Description	Method of Filing
*10.17	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of November 13, 2018, by and between the Company and Jonathan M. Lushko.	Filed herewith as Exhibit 10.17.
*10.18	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated July 29, 2015, by and between the Company and Steven T. Schlotterbeck.	Incorporated herein by reference to Exhibit 10.5 to Form 8-K (#001-3551) filed on July 31, 2015.
*10.19(a)	Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated July 29, 2015, by and between the Company and David L. Porges.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on July 31, 2015.
*10.19(b)	Executive Alternative Work Arrangement Employment Agreement, dated October 26, 2018, by and between the Company and David L. Porges.	Filed herewith as Exhibit 10.19(b).
*10.20(a)	Second Amended and Restated Confidentiality, Non-Solicitation and Non-Competition Agreement, dated March 1, 2017, by and between the Company and David E. Schlosser, Jr.	Incorporated herein by reference to Exhibit 10.17 to Form 10-K (#001-3551) for the year ended December 31, 2017.
*10.20(b)	Agreement and Release, dated October 26, 2018, by and between the Company and David E. Schlosser, Jr.	Filed herewith as Exhibit 10.20(b).
*10.21(a)	Offer Letter, dated as of July 26, 2017, by and between the Company and Jeremiah J. Ashcroft II	Incorporated herein by reference to Exhibit 10.18(a) to Form 10-K (#001-3551) for the year ended December 31, 2017.
*10.21(b)	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated as of August 7, 2017, by and between the Company and Jeremiah J. Ashcroft III.	Incorporated herein by reference to Exhibit 10.18(b) to Form 10-K (#001-3551) for the year ended December 31, 2017.
*10.21(c)	Agreement and Release, dated as of August 13, 2018, by and between the Company and Jeremiah J. Ashcroft III.	Incorporated herein by reference to Exhibit 10.1 to Form 10-Q (#001-3551) for the quarter ended September 30, 2018.
*10.22	Form of Amendment of Confidentiality, Non-Solicitation and Non-Competition Agreement.	Filed herewith as Exhibit 10.22.
21	Schedule of Subsidiaries	Filed herewith as Exhibit 21.
23.01	Consent of Independent Registered Public Accounting Firm	Filed herewith as Exhibit 23.01.
23.02	Consent of Ryder Scott Company, L.P.	Filed herewith as Exhibit 23.02.
31.01	Rule 13(a)-14(a) Certification of Principal Executive Officer	Filed herewith as Exhibit 31.01.
31.02	Rule 13(a)-14(a) Certification of Principal Financial Officer	Filed herewith as Exhibit 31.02.
32	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer	Furnished herewith as Exhibit 32.
99	Independent Petroleum Engineers' Audit Report	Filed herewith as Exhibit 99.
101	Interactive Data File	Filed herewith as Exhibit 101.

Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (*)

The Company agrees to furnish to the SEC, upon request, copies of instruments with respect to long-term debt which have not previously been filed.

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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.

EQT CORPORATION

By: /s/ ROBERT J. MCNALLY
Robert J. McNally
President and Chief Executive Officer
February 14, 2019

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.

/s/ ROBERT J. MCNALLY Robert J. McNally (Principal Executive Officer)	President, Chief Executive Officer and Director	February 14, 2019
/s/ JIMMI SUE SMITH Jimmi Sue Smith (Principal Financial Officer)	Senior Vice President and Chief Financial Officer	February 14, 2019
/s/ JEFFERY C. MITCHELL Jeffery C. Mitchell (Principal Accounting Officer)	Vice President and Principal Accounting Officer	February 14, 2019
/s/ PHILIP G. BEHRMAN Philip G. Behrman	Director	February 14, 2019
/s/ A. BRAY CARY JR. A. Bray Cary, Jr.	Director	February 14, 2019
/s/ CHRISTINA A. CASSOTIS Christina A. Cassotis	Director	February 14, 2019
/s/ WILLIAM M. LAMBERT William M. Lambert	Director	February 14, 2019
/s/ GERALD F. MACCLEARY Gerald F. MacCleary	Director	February 14, 2019
/s/ ANITA M. POWERS Anita M. Powers	Director	February 14, 2019
/s/ DANIEL J. RICE IV Daniel J. Rice IV	Director	February 14, 2019
/s/ JAMES E. ROHR James E. Rohr	Chairman	February 14, 2019

/s/ STEPHEN A. THORINGTON Stephen A. Thorington	Director	February 14, 2019
/s/ LEE T. TODD, JR. Lee T. Todd, Jr.	Director	February 14, 2019
/s/ CHRISTINE J. TORETTI Christine J. Toretti	Director	February 14, 2019