

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

**FORM 10-K**

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934  
**FOR THE FISCAL YEAR ENDED DECEMBER 31, 2020**

or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934  
**FOR THE TRANSITION PERIOD FROM \_\_\_\_\_ TO \_\_\_\_\_**

COMMISSION FILE NUMBER 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)

**(412) 553-5700**

(Registrant's telephone number, including area code)

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

Title of each class	Trading symbol(s)	Name of each exchange on which registered
Common Stock, no par value	EQT	New York Stock Exchange

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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.

Large accelerated filer	<input checked="" type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
		Emerging growth company	<input type="checkbox"/>

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of common stock held by non-affiliates of the registrant as of June 30, 2020: \$3.0 billion

As of February 12, 2021, 278,854,465 shares of common stock, no par value, of the registrant were outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

EQT Corporation's definitive proxy statement relating to its 2021 annual meeting of shareholders will be filed with the Securities and Exchange Commission within 120 days after the close of EQT Corporation's fiscal year ended December 31, 2020 and is incorporated by reference in Part III to the extent described therein.

**TABLE OF CONTENTS**

	<u>Page</u>
<a href="#">Glossary of Commonly Used Terms, Abbreviations and Measurements</a>	<a href="#">3</a>
<a href="#">Cautionary Statements</a>	<a href="#">6</a>
<b>PART I</b>	
<a href="#">Item 1. Business</a>	<a href="#">7</a>
<a href="#">Item 1A. Risk Factors</a>	<a href="#">21</a>
<a href="#">Item 1B. Unresolved Staff Comments</a>	<a href="#">40</a>
<a href="#">Item 2. Properties</a>	<a href="#">40</a>
<a href="#">Item 3. Legal Proceedings</a>	<a href="#">40</a>
<a href="#">Item 4. Mine Safety Disclosures</a>	<a href="#">41</a>
<a href="#">Executive Officers of the Registrant</a>	<a href="#">42</a>
<b>PART II</b>	
<a href="#">Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</a>	<a href="#">43</a>
<a href="#">Item 6. Selected Financial Data</a>	<a href="#">45</a>
<a href="#">Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations</a>	<a href="#">45</a>
<a href="#">Item 7A. Quantitative and Qualitative Disclosures About Market Risk</a>	<a href="#">57</a>
<a href="#">Item 8. Financial Statements and Supplementary Data</a>	<a href="#">59</a>
<a href="#">Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</a>	<a href="#">111</a>
<a href="#">Item 9A. Controls and Procedures</a>	<a href="#">111</a>
<a href="#">Item 9B. Other Information</a>	<a href="#">112</a>
<b>PART III</b>	
<a href="#">Item 10. Directors, Executive Officers and Corporate Governance</a>	<a href="#">112</a>
<a href="#">Item 11. Executive Compensation</a>	<a href="#">112</a>
<a href="#">Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</a>	<a href="#">113</a>
<a href="#">Item 13. Certain Relationships and Related Transactions, and Director Independence</a>	<a href="#">114</a>
<a href="#">Item 14. Principal Accounting Fees and Services</a>	<a href="#">114</a>
<b>PART IV</b>	
<a href="#">Item 15. Exhibits and Financial Statement Schedules</a>	<a href="#">115</a>
<a href="#">Item 16. Form 10-K Summary</a>	<a href="#">120</a>
<a href="#">Signatures</a>	<a href="#">121</a>

## Glossary of Commonly Used Terms, Abbreviations and Measurements

*Unless the context otherwise indicates, all references in this report to "EQT," the "Company," "we," "us," or "our" are to EQT Corporation and its subsidiaries, collectively.*

### 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 by 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.

**conventional reservoir** – an area believed to be capable of producing crude oil and natural gas occurring in discrete accumulations in structural and stratigraphic traps utilizing conventional recovery methods.

**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 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 we have 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.

**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 isobutane.

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

**net revenue interest** – the interest retained by us 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 natural gas, NGLs and oil, 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.

**proved developed reserves** – proved reserves that 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.

**reliable technology** – a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonable certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

**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.

**stratigraphic test well** – a hole drilled for the sole purpose of gaining structural or stratigraphic information to aid in exploring for oil and gas.

**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.

**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.

#### Abbreviations

**CFTC** – Commodity Futures Trading Commission

**EPA** – U.S. Environmental Protection Agency

**ESG** – Environmental, Social and Governance initiatives

**FERC** – Federal Energy Regulatory Commission

**GAAP** – U.S. Generally Accepted Accounting Principles

**IRS** – Internal Revenue Service

**NYMEX** – New York Mercantile Exchange

**OTC** – over the counter

**SEC** – U.S. Securities and Exchange Commission

Measurements

<b>Bbl</b>	= barrel
<b>Bcf</b>	= billion cubic feet
<b>Bcfe</b>	= 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
<b>Btu</b>	= one British thermal unit
<b>Dth</b>	= dekatherm or million British thermal units
<b>Mbbl</b>	= thousand barrels
<b>Mcf</b>	= thousand cubic feet
<b>Mcfe</b>	= 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
<b>MMbbl</b>	= million barrels
<b>MMBtu</b>	= million British thermal units
<b>MMcf</b>	= million cubic feet
<b>MMcfe</b>	= 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
<b>MMDth</b>	= million dekatherm
<b>Tcfe</b>	= 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

## 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 are usually identified by the use of words such as "anticipate," "estimate," "could," "would," "will," "may," "forecast," "approximate," "expect," "project," "intend," "plan," "believe" and other words of similar meaning, or the negative thereof, 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 sections "Strategy" and "Outlook" in Item 1., "Business," section "Impairment of Oil and Gas Properties" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the expectations of our plans, strategies, objectives and growth and anticipated financial and operational performance, including guidance regarding our strategy to develop our reserves; drilling plans and programs (including availability of capital to complete such plans and programs); the projected scope and timing of our combo-development projects; estimated reserves, including potential future downward adjustments of reserves and reserve life; total resource potential and drilling inventory duration; projected production and sales volumes and growth rates (including liquids production and sales volumes and growth rates); natural gas prices, changes in basis and the impact of commodity prices on our business; potential impacts to our business and operations resulting from COVID-19 or a similar pandemic; potential future impairments of our assets; our ability to reduce our drilling and completions costs, other costs and expenses and capital expenditures, and the timing of achieving any such reductions; infrastructure programs; the cost, capacity and timing of obtaining regulatory approvals; our ability to successfully implement and execute our operational, organizational, technological and ESG initiatives, and achieve the anticipated benefits of such initiatives; projected reductions of our gathering and compression rates resulting from our consolidated gathering agreement with EQM Midstream Partners, LP, and the anticipated cost savings and other strategic benefits associated with the execution of such agreement; monetization transactions, including asset sales, joint ventures or other transactions involving our assets, and our planned use of the proceeds from any such monetization transactions; potential acquisitions or other strategic transactions, the timing thereof and our ability to achieve the intended operational, financial and strategic benefits from any such transactions; the timing and structure of any dispositions of our remaining retained shares of Equitrans Midstream Corporation's (Equitrans Midstream's) common stock, and the planned use of the proceeds from any such dispositions; the amount and timing of any repayments, redemptions or repurchases of our common stock, outstanding debt securities or other debt instruments; our ability to reduce our debt and the timing of such reductions, if any; projected dividend amounts and rates; projected cash flows and free cash flow; projected capital expenditures; liquidity and financing requirements, including funding sources and availability; our ability to maintain or improve our credit ratings, leverage levels and financial profile; our hedging strategy; the effects of litigation, government regulation and tax position; and the expected impact of changes to tax laws. 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. We have based these forward-looking statements on current expectations and assumptions about future events, taking into account all information currently known by us. While we consider 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 our control. The risks and uncertainties that may affect the operations, performance and results of our business and forward-looking statements include, but are not limited to, those set forth in Item 1A., "Risk Factors" in this Annual Report on Form 10-K, and other documents we file from time to time with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made, and we do 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 our 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, 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 us. The agreements may contain representations and warranties by us, 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, such representations and warranties alone may not describe our actual state of affairs or the affairs of our affiliates as of the date they were made or at any other time and should not be relied upon as statements of fact.

## PART I

### Item 1. Business

#### General

We are a natural gas production company with operations focused in the Marcellus and Utica Shales of the Appalachian Basin. Based on average daily sales volumes, we are the largest producer of natural gas in the United States. As of December 31, 2020, we had 19.8 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 1.8 million gross acres, including approximately 1.5 million gross acres in the Marcellus play.

#### Strategy

We are committed to responsibly developing our world-class asset base and being the operator of choice for all stakeholders. By promoting a culture that prioritizes operational efficiency, technology and sustainability, we seek to continuously improve the way we produce environmentally responsible, reliable low-cost energy. We believe that the scale and contiguity of our acreage position differentiates us from our Appalachian Basin peers and that our evolution into a modern, digitally-enabled exploration and production business enhances our strategic advantage.

Our operational strategy focuses on the successful execution of combo-development projects. Combo-development refers to the development of several multi-well pads in tandem. Combo-development generates value across all levels of the reserves development process by maximizing operational and capital efficiencies. In the drilling stage, rigs spend more time drilling and less time transitioning to new sites. Advanced planning, a prerequisite to pursuing combo-development, facilitates the delivery of bulk hydraulic fracturing sand and piped fresh water (as opposed to truck-transported water), the ability to continuously meet completions supply needs and the use of environmentally friendly technologies. Operational efficiencies realized from combo-development are passed on to our service providers, which reduces overall contract rates.

The benefits of combo-development extend beyond financial gains to include environmental and social interests. We have developed an integrated ESG program that interplays with our combo-development-driven operational strategy. Core tenets of our ESG program include investing in technology and human capital; improving data collection, analysis and reporting; and engaging with stakeholders to understand, and align our actions with, their needs and expectations. Combo-development, when compared to similar production from non-combo-development operations, translates into fewer trucks on the road, decreased fuel usage, shorter periods of noise pollution, fewer areas impacted by midstream pipeline construction and shortened duration of site operations, all of which fosters a greater focus on safety and environmental protection.

Combo-development projects require significant advanced planning, including the establishment of a large, contiguous leasehold position; the advanced acquisition of regulatory permits and sourcing of fracturing sand and water; the timely verification of midstream connectivity; and the ability to quickly respond to internal and external stimuli. Without a modern, digitally-connected operating model or an acreage position that enables operations of this scale, combo-development would not be possible.

We believe that our proprietary digital work environment in conjunction with the size and contiguity of our asset base uniquely position us to execute on a multi-year inventory of combo-development projects in our core acreage position. Our operational strategy employs this differentiation to advance our mission of being the operator of choice for all stakeholders. We believe that combo-development projects are key to delivering sustainably low well costs and higher returns on invested capital and that our long-term transformative plan has been designed to create value by leveraging our strategic advantage, both operational and environmental, over our peers.

#### 2020 Highlights

- Achieved 2020 sales volumes of 1,498 Bcfe or average daily sales volumes of 4.1 Bcfe per day; received an average realized price of \$2.37 per Mcfe.
- Reduced 2020 capital expenditures by \$694 million, or 39.1%, compared to 2019, while delivering flat sales volumes.
- Increased total proved reserves by 2.3 Tcfe or 13% in 2020 compared to 2019.
- Decreased total debt by \$368 million and addressed near-term maturities, improving our financial position.
- Executed a new gas gathering agreement and exchanged half of our equity stake in Equitrans Midstream, substantially reducing our future gathering fee structure.

- Acquired strategic assets from Chevron U.S.A. Inc. located in the Appalachian Basin for an aggregate purchase price of \$735 million (Chevron Acquisition).
- Divested certain non-strategic assets for an aggregate purchase price of \$125 million.
- Executed long-term contract to use electric hydraulic fracturing services in our completions operations, promoting our ESG initiatives.
- Received approximately \$440 million in federal income tax refunds, including interest.

## Outlook

In 2021, we expect to spend approximately \$1.1 to \$1.2 billion in total capital expenditures, excluding amounts attributable to noncontrolling interests. We expect to fund planned capital expenditures with cash generated from operations, allocated as follows: approximately \$800 to \$850 million to fund reserve development, approximately \$125 to \$140 million to fund land and lease acquisitions, approximately \$130 to \$155 million to fund other production infrastructure and approximately \$45 to \$55 million applied towards capitalized overhead. Reserve development capital expenditures will be spent across our three primary operating areas, with approximately 65% spent in Pennsylvania Marcellus, approximately 30% spent in West Virginia Marcellus, and approximately 5% spent in Ohio Utica. Our 2021 capital expenditure program is expected to deliver sales volumes of 1,620 Bcfe to 1,700 Bcfe, an increase of 120-200 Bcfe when compared to 2020 sales volumes primarily driven by increased production from the Chevron Acquisition.

Our revenues, earnings, liquidity and ability to grow are substantially dependent on the prices we receive for, and our ability to develop our reserves of, natural gas, NGLs and oil. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas, NGLs and oil at our ultimate sales points and, thus, cannot predict the ultimate impact of prices on our operations. Changes in natural gas, NGLs and oil prices could affect, among other things, our development plans, which would increase or decrease the pace of the development and the level of our reserves, as well as our revenues, earnings or liquidity. Lower prices and changes in our development plans could also result in non-cash impairments in the book value of our oil and gas properties or downward adjustments to our estimated proved reserves. Any such impairments or downward adjustments to our estimated reserves could potentially be material to us.

See "Impairment of Oil and Gas Properties" 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 our accounting policies and significant assumptions related to accounting for gas, NGL and oil producing activities and our accounting policies and processes related to impairment reviews for proved and unproved property.

## Segment and Geographical Information

Our operations consist of one reportable segment. We have a single, company-wide management team that administers all properties as a whole rather than by discrete operating segments. We measure financial performance as a single enterprise and not on an area-by-area basis. Substantially all of our assets and operations are located in the Appalachian Basin.

## Reserves

The following tables summarize our proved developed and undeveloped natural gas, NGLs and crude oil reserves using average first-day-of-the-month closing prices for the prior twelve months and disaggregated by product and play. Substantially all of our reserves reside in continuous accumulations.

	December 31, 2020		
	Natural Gas	NGLs and Crude Oil	Total
	(Bcf)	(MMbbl)	(Bcfe)
Proved developed reserves	12,750	148	13,641
Proved undeveloped reserves	6,115	8	6,161
Total proved reserves	18,865	156	19,802

	December 31, 2020				
	Marcellus	Upper Devonian	Ohio Utica	Other	Total
	(Bcfe)				
Proved developed reserves	11,943	839	757	102	13,641
Proved undeveloped reserves	6,061	—	100	—	6,161
Total proved reserves	18,004	839	857	102	19,802

The following table summarizes our proved developed and undeveloped reserves using average first-day-of-the-month closing prices for the prior twelve months and disaggregated by state.

	December 31, 2020			
	Pennsylvania	West Virginia	Ohio	Total
	(Bcfe)			
Proved developed producing reserves	9,590	2,749	757	13,096
Proved developed non-producing reserves	538	7	—	545
Proved undeveloped reserves	4,465	1,596	100	6,161
Total proved reserves	14,593	4,352	857	19,802
Gross proved undeveloped drilling locations	201	73	5	279
Net proved undeveloped drilling locations	169	65	5	239

Our 2020 total proved reserves increased by 2.3 Tcfe, or 13%, compared to 2019 due to extensions, discoveries and other additions of 3,446 Bcfe and the acquisition of 1,381 Bcfe from the Chevron Acquisition, partly offset by production of 1,498 Bcfe, revisions to previous estimates of 739 Bcfe and divestitures of 257 Bcfe. We have an additional 13 Tcfe of reserves that meet the definition of proved reserves, except they are planned to be developed beyond five years and are therefore not included in the current estimate of proved reserves.

During 2020, we conducted a study of our reserves areas to determine the reliability of the technology used in calculating our reserves. This study demonstrated that technologies used in the course of our reserves determination are reliable, provide reasonable certainty of future performance and economics of our wells, and conform to booking practices when using reliable technologies. The technologies used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, production data, decline curve analysis, well logs, geologic maps, core data, seismic data, demonstrated relationship between geologic parameters and performance, and the implementation and application of statistical analysis.

Proved undeveloped reserves increased by 1,136 Bcfe, or 23%, in 2020 from 2019. The following table provides a rollforward of our proved undeveloped reserves.

	Proved Undeveloped Reserves
	(Bcfe)
Balance at January 1, 2020	5,025
Conversions into proved developed reserves	(2,102)
Acquisition of in-place reserves	171
Revision of previous estimates (a)	(355)
Extensions, discoveries and other additions (b)	3,422
Balance at December 31, 2020	6,161

- (a) Composed of (i) negative revisions of 510 Bcfe from proved undeveloped locations that are no longer expected to be developed within five years of initial booking as proved reserves as a result of changes to our development plan which included 245 Bcfe from lower pricing that impacted well economics, shifting capital from the Ohio Utica, to Pennsylvania and West Virginia Marcellus and 265 Bcfe as a result of continued implementation of our combo-development strategy; and (ii) positive revisions of 155 Bcfe due primarily to changes in working interests and net revenue interests as well as revisions to type curves.
- (b) Composed of (i) 2,096 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved using reliable technologies which expanded the number of our technically proven locations; (ii) 1,295 Bcfe due to additions

associated with directly offsetting development; and (ii) 31 Bcfe from the extension of lateral lengths of proved undeveloped reserves.

As of December 31, 2020, we had zero wells with proved undeveloped reserves that had remained undeveloped for more than five years from their time of booking.

See Note 18 to the Consolidated Financial Statements for further discussion of the preparation of, and year-over-year changes in, our reserves estimate and calculation of our standardized measure of estimated future net cash flows from natural gas and crude oil reserves.

As of December 31, 2020, the standardized measure of our estimated future net cash flows from natural gas and crude oil reserves, which is calculated using average first-day-of-the-month closing prices for the prior twelve months (which is referred to as SEC pricing), was \$3,366 million as described in Note 18 to the Consolidated Financial Statements. If the prices used in the calculation of the standardized measure instead reflected five-year strip pricing as of December 31, 2020 and held constant thereafter using (i) the NYMEX five-year strip adjusted for regional differentials using Texas Eastern Transmission Corp. M-2, for gas and (ii) the NYMEX WTI five-year strip for oil, adjusted for regional differentials consistent with those used in the standardized measure, and with all other assumptions held constant, our total proved reserves would be 20,296 Bcfe, the standardized measure of our discounted net future cash flows after taxes of our proved reserves would be \$8,952 million, and the discounted future net cash flows before taxes would be \$10,152 million. The average realized product prices weighted by production over the remaining lives of the properties would be \$27.18 per barrel of oil, \$13.55 per barrel of NGL and \$2.075 per Mcf of gas (as compared to \$20.94 per barrel of oil, \$11.97 per barrel of NGL and \$1.38 per Mcf of gas using SEC pricing, as described in Note 18). The NYMEX strip price proved reserves and related metrics are intended to illustrate reserve sensitivities to market expectations of commodity prices and should not be confused with “SEC pricing” proved reserves and do not comply with SEC pricing assumptions. We believe that the presentation of reserve volumes and related metrics using NYMEX forward strip prices provides investors with additional useful information about our reserves because the forward prices are based on the market’s forward-looking expectations of oil and gas prices as of a certain date. The price at which we can sell our production in the future is the major determinant of the likely economic producibility of our reserves. We hedge substantial amounts of future production based upon futures prices. In addition, we use such forward-looking market-based data in developing our drilling plans, assessing our capital expenditure needs and projecting future cash flows. While NYMEX strip prices represent a consensus estimate of future pricing, such prices are only an estimate and not necessarily an accurate projection of future oil and gas prices. Actual future prices may vary significantly from the NYMEX prices; therefore, actual revenue and value generated may be more or less than the amounts disclosed. Investors should be careful to consider forward prices in addition to, and not as a substitute for, SEC pricing, when considering our reserves.

Based on our mix of proved undeveloped and probable reserves, we estimate that we have an undeveloped drilling inventory of approximately 1,660 net locations in Pennsylvania and West Virginia Marcellus. At our current drilling pace, these net locations provide more than 15 years of drilling inventory based on net undeveloped Marcellus acres, average expected lateral length of 12,000 feet and well spacing of 1,000 feet. We believe that our combo-development strategy, coupled with our undeveloped inventory located in a premier core asset base, will lead to sustainable free cash flow generation and higher returns on invested capital.

The following table summarizes our capital expenditures for reserve development.

	Years Ended December 31,		
	2020	2019	2018
	(Millions)		
Marcellus (includes Upper Devonian)	\$ 737	\$ 1,184	\$ 1,889
Utica	102	193	360
Total	<u>\$ 839</u>	<u>\$ 1,377</u>	<u>\$ 2,249</u>

Lease operating costs, excluding production taxes, for the years ended December 31, 2020, 2019 and 2018 was \$0.07, \$0.06 and \$0.07, respectively.

## Properties

The majority of our acreage is held by lease or occupied under perpetual easements or other rights acquired, for the most part, without warranty of underlying land titles. Approximately 24% of our total gross acres is developed. We retain deep drilling rights on the majority of our acreage.

The following table summarizes our acreage disaggregated by state.

	December 31, 2020			
	Pennsylvania	West Virginia	Ohio	Total
Total gross productive acreage	319,504	84,374	46,688	450,566
Total gross undeveloped acreage	818,345	448,401	125,995	1,392,741
Total gross acreage	1,137,849	532,775	172,683	1,843,307
Total net productive acreage	289,820	83,720	33,906	407,446
Total net undeveloped acreage	709,845	352,402	109,115	1,171,362
Total net acreage	999,665	436,122	143,021	1,578,808
Average net revenue interest of proved developed reserves	72.9 %	83.0 %	48.8 %	72.7 %

We have an active lease renewal program in areas targeted for development. In the event that production is not established or we take no action to extend or renew the terms of our leases, 71,322, 69,813 and 40,958 of our net undeveloped acreage as of December 31, 2020 will expire in the years ending December 31, 2021, 2022 and 2023, respectively.

The following tables summarize our productive and in-process natural gas wells. We had no productive or in-process oil wells as of December 31, 2020.

	December 31, 2020
<b>Productive wells:</b>	
Total gross	3,203
Total net	2,852
<b>In-process wells:</b>	
Total gross	392
Total net	373

	December 31, 2020			
	Pennsylvania	West Virginia	Ohio	Total
Total gross productive wells (a)	2,252	685	266	3,203
Total net productive wells	2,059	659	134	2,852

(a) Of our total gross productive wells, there are 613 gross conventional wells in Pennsylvania and 4 gross conventional wells in West Virginia. We have no gross conventional wells in Ohio.

The following table summarizes our net development wells drilled. There were no net productive or net dry exploratory wells drilled during the years ended December 31, 2020, 2019 and 2018.

	Years Ended December 31,		
	2020	2019	2018
<b>Net development wells:</b>			
Productive	120	145	210
Dry (a)	—	—	5

(a) Dry development wells are related primarily to non-core wells that we no longer plan to drill to depth or complete, acquired wells with mechanical integrity issues and wells that have been plugged and abandoned due to future mining operations or mechanical integrity issues.

During 2020, we commenced drilling operations (spud) on 88 gross wells (84 net), including 66 Pennsylvania Marcellus gross wells (65 net), 17 West Virginia Marcellus gross wells (16 net) and 5 Ohio Utica gross wells (3 net).

Our sales volumes in 2020 from the Marcellus play, including the Upper Devonian play, were 1,315 Bcfe. The following table summarizes our produced and sold volumes by state.

	Pennsylvania	West Virginia	Ohio	Other (a)	Total
	(MMcfe)				
<b>Produced and sold natural gas, NGLs and oil for the years ended December 31,</b>					
2020	1,051,869	267,708	178,215	—	1,497,792
2019	1,001,973	274,378	231,545	—	1,507,896
2018	922,033	323,976	209,428	32,252	1,487,689

(a) Primarily Kentucky and Virginia.

## Markets and Customers

**Natural Gas Sales.** Natural gas is a commodity and, therefore, we typically receive market-based pricing. The market price for natural gas in the Appalachian Basin is typically lower relative to NYMEX Henry Hub, Louisiana (the location for pricing NYMEX natural gas futures) as a result of increased supply of natural gas in the Northeast United States. To protect cash flow from undue exposure to the risk of changing commodity prices, we hedge a portion of our forecasted natural gas production at, for the most part, NYMEX natural gas prices. For information on our hedging strategy and our derivative instruments, refer to "Commodity Risk Management" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations," Item 7A., "Quantitative and Qualitative Disclosures About Market Risk" and Note 3 to the Consolidated Financial Statements.

**NGLs Sales.** We primarily sell NGLs recovered from our natural gas production. We primarily contract with MarkWest Energy Partners, L.P. (MarkWest) to process our natural gas and extract from the produced natural gas heavier hydrocarbon streams (consisting predominately of ethane, propane, isobutane, normal butane and natural gasoline). We also contract with MarkWest to market a portion of our NGLs. In addition, we have contractual arrangements with Williams Ohio Valley Midstream LLC to process our natural gas and market a portion of our NGLs.

**Average Sales Price.** The following table presents our average sales price per unit of natural gas, NGLs and oil, with and without the effects of cash settled derivatives, as applicable.

	Years Ended December 31,		
	2020	2019	2018
<b>Natural gas (\$/Mcf):</b>			
Average sales price, excluding cash settled derivatives	\$ 1.73	\$ 2.48	\$ 3.04
Average sales price, including cash settled derivatives	2.37	2.65	2.89
<b>NGLs, excluding ethane (\$/Bbl):</b>			
Average sales price, excluding cash settled derivatives	\$ 20.51	\$ 23.63	\$ 37.63
Average sales price, including cash settled derivatives	20.39	25.82	36.56
<b>Ethane (\$/Bbl):</b>			
Average sales price, excluding cash settled derivatives	\$ 3.48	\$ 6.16	\$ 8.09
Average sales price, including cash settled derivatives	3.48	7.18	8.09
<b>Oil (\$/Bbl):</b>			
Average sales price	\$ 25.57	\$ 40.90	\$ 52.70
<b>Natural gas, NGLs and oil (\$/Mcf):</b>			
Average sales price, excluding cash settled derivatives	\$ 1.77	\$ 2.51	\$ 3.15
Average sales price, including cash settled derivatives	2.37	2.69	3.01

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."

**Natural Gas Marketing.** EQT Energy, LLC, our indirect, wholly-owned marketing subsidiary, provides marketing services and contractual pipeline capacity management services primarily for our benefit. EQT Energy, LLC also engages in risk management and hedging activities to limit our exposure to shifts in market prices.

*Customers.* We sell natural gas and NGLs to marketers, utilities and industrial customers located in the Appalachian Basin and in markets that are accessible through our transportation portfolio, particularly where there is expected future demand growth, such as in the Gulf Coast, Midwest and Northeast United States and Canada. As of December 31, 2020, approximately 60% of our sales volumes reach markets outside of Appalachia. We do not depend on any single customer and believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil.

We have access to approximately 2.5 Bcf per day of firm pipeline takeaway capacity and 0.9 Bcf per day of firm processing capacity. In addition, we are committed to an initial 1.29 Bcf per day of firm capacity on the Mountain Valley Pipeline upon its in-service date. These firm transportation and processing agreements may require minimum volume delivery commitments, which we expect to principally fulfill with production from existing reserves.

We have contractually agreed to deliver firm quantities of gas and NGLs to various customers, which we expect to fulfill with production from existing reserves. We regularly monitor our proved developed reserves to ensure sufficient availability to meet commitments for the next one to three years. The following table summarizes our total gross commitments as of December 31, 2020.

Years ending December 31,	Natural Gas	NGLs
	(Bcf)	(Mbbbl)
2021	1,390	7,814
2022	917	2,658
2023	780	1,825
2024	601	1,830
2025	388	1,825
Thereafter	2,587	600

### Seasonality

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or hot summers may also impact demand.

### Competition

Other natural gas producers compete with us 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. Our competitors include independent oil and gas companies, major oil and gas companies, individual producers, operators and marketing companies and other energy companies that produce substitutes for the commodities that we produce.

### Regulation

*Regulation of our Operations.* Our exploration and production operations are subject to various types of federal, state and local laws and regulations, including regulations related to the following: 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 our natural gas resources.

Our operations are also subject to conservation and correlative rights regulations, including the following: 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. Ohio 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, we must rely on voluntary pooling of lands and leases for Marcellus and Upper Devonian acreage. In Pennsylvania, lease integration legislation 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 us.

We maintain limited gathering operations that are subject to various types of federal and state environmental laws and local zoning ordinances, including the following: 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, including regulations by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration; 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 OTC derivative market and entities, such as us, 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. Among other things, the Dodd-Frank Act established margin requirements and requires clearing and trade execution practices for certain categories of swaps and may result in certain market participants needing to curtail their derivative activities. Although some of the rules necessary to implement the Dodd-Frank Act have yet to be adopted, regulators have issued numerous rules under the Dodd-Frank Act, including a rule establishing an “end-user” exception to mandatory clearing (End-User Exception), a rule regarding margin for certain uncleared swaps (Margin Rule) and a rule imposing federal position limits on certain futures contracts relating to energy products, including natural gas (Position Limits Rule).

We qualify as a “non-financial entity” for purposes of the End-User Exception and, as such, we are eligible for such exception. As a result, our hedging activities are not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing, although we are subject to certain recordkeeping and reporting obligations associated with such rule. We also qualify as a “non-financial end user” for purposes of the Margin Rule; therefore, our uncleared swaps are not subject to regulatory margin requirements. Finally, although the Position Limits Rule does not go into effect with respect to energy products until January 1, 2022, we believe that the majority, if not all, of our hedging activities constitute bona fide hedging under the Position Limits Rule and will not be subject to the limitations under such rule. However, many of our hedge counterparties and other market participants are not eligible for the End-User Exception, are subject to mandatory clearing and the Margin Rule for swaps with some or all of their other swap counterparties, and may be subject to the Position Limits Rule, which may affect the pricing and/or availability of derivatives for us. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations related to derivatives which apply to our transactions with counterparties subject to such foreign regulations.

Regulators periodically review or audit our compliance with applicable regulatory requirements. We anticipate that compliance with existing laws and regulations governing current operations will not have a material adverse effect upon our 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. We cannot predict when or whether any such proposals may become effective or the effect that such proposals may have on us.

The following is a summary of some of the existing laws, rules and regulations to which our 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 transportation 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 we produce and the manner in which we market our 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 our sales of our 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 our production activities have not been regulated by the FERC as a natural gas company under the NGA, we are required to report aggregate volumes of natural gas purchased or sold at wholesale

to the extent such transactions use, 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 our otherwise non-FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject us to civil penalty liability.

The CFTC also holds authority to monitor certain segments of the physical and futures energy commodities market including natural gas, NGLs and oil. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation and disruptive trading practices 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 we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of natural gas and release of our 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 non-unduly discriminatory 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, we cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our 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 negotiated rates, both of which are subject to FERC approval. The FERC also allows jurisdictional gas pipeline companies to charge market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of FERC-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, our costs of transporting gas to point of sale locations may increase. We believe that the third-party natural gas pipelines on which our 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 company. However, the distinction between the FERC-regulated transportation services and federally unregulated gathering services could be subject to potential 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. Our 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. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Some of our transportation of oil and NGLs is through FERC-regulated 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 FERC published the five-year index level for 2021-2026 in December 2020. We are 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 our crude oil producing operations.

*Environmental, Health and Safety Regulation.* Our business operations 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. We must take into account environmental, health and safety regulations in, among other things, planning, designing, constructing, operating and plugging 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 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. We cannot predict when or whether any such proposals may become effective. Therefore, we are 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. We have established procedures, however, for the ongoing evaluation of our 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 our business operations are subject and for which compliance may have a material adverse impact on our 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 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, we generate materials in the course of our operations that may be regulated as hazardous substances based on their characteristics; however, we are unaware of any liabilities arising under CERCLA for which we may be held responsible that would materially and adversely affect us.

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. In April 2019, following litigation and a resulting consent decree related to the EPA's requirements under RCRA to review oil and gas waste regulations, the EPA determined that revisions to the regulations were not required, concluding that any adverse effects related to oil and gas waste were more appropriately and readily addressed within the framework of existing state regulatory programs. Any changes to state or federal programs could result in an increase in our costs to manage and dispose waste, which could have a material adverse effect on our results of operations and financial condition.

We currently own, lease or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have used operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including offshore locations, where such substances have been taken for recycling or disposal. In addition, some of our 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 our control. We are able to control directly the operation of only those wells with respect to which we act or have acted as operator. The failure of a prior owner or operator to comply with applicable environmental regulations may, in certain circumstances, be attributed to us 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, we 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 June 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), which was stayed nationwide in October 2015 pending resolution of several legal challenges. The EPA and the Corps proposed a rule in July 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, which lifted the stay and resulted in a patchwork application of the rule in some states, but not in others. In October 2019, the EPA issued a final rule repealing the WOTUS rule and the repeal rule became effective in December 2019. In April 2020, the EPA and the Corps published the Navigable Waters Protection Rule (NWPR), which narrowed the definition of WOTUS to four categories of jurisdictional waters and includes twelve categories of exclusions, including groundwater. A coalition of states and cities, environmental groups, and agricultural groups have challenged the NWPR and a federal district court in Colorado stayed implementation of the rule. The stay is limited to application of the rule in Colorado; the rule has taken effect in all other states. In addition, in an April 2020 decision defining the scope of the CWA that was handed down just days after the NWPR was published, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. The Court rejected the EPA and Corps' assertion that groundwater should be totally excluded from the CWA. The Court's decision is expected to bolster challenges to the NWPR. On January 20, 2021, the Biden Administration announced it will review the NWPR in accordance with the January 20, 2021 Executive Order that revokes President Trump's Executive Order 13778, which required review and reversal of the WOTUS rule. The EPA and the Corps have requested to stay the litigation over the NWPR during the agencies' review of the rule. To the extent a revised 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, which could delay the development of our natural gas and oil projects. Also, pursuant to these laws and regulations, we 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 us 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 use 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 our oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. Reclassification of areas or imposition of more stringent standards may make it more difficult to construct new facilities or modify existing facilities in any newly designated non-attainment areas. Compliance with more stringent standards and other environmental regulations could delay or prohibit our ability to obtain permits for our operations or require us 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 are required to meet "best available control technology" standards established by the states or, in some cases, by the EPA on a case-by-case basis. These CAA requirements 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 oil and gas production sources in the United States on an annual basis, which include certain of our operations.

In June 2016, the EPA finalized new regulations that established 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. In September 2020, the EPA finalized amendments to the 2016 Subpart OOOOa standards, known as the Reconsideration Rule, that 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. In September 2020, the EPA issued a rule to revise Subpart OOOOa to rescind the methane-specific requirements for certain oil and natural gas sources in the production and processing segments, known as the Review Rule. Both the Reconsideration Rule and the Review Rule are subject to pending litigation. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the Reconsideration Rule by September 2021 and consider revising the Review Rule. As a result of the actions described above, we 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 May 2020, the Pennsylvania Environmental Quality Board (EQB) published in the Pennsylvania Bulletin a proposed rulemaking for the control of emissions of VOCs and other pollutants for existing sources. EQB accepted public comments on the proposed rulemaking through July 2020; however, a final rulemaking has yet to be approved by the EQB. State regulations such as these 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 GHGs. In October 2019, Pennsylvania Governor Tom Wolf signed an Executive Order directing the PADEP to draft regulations establishing a cap-and-trade program under its existing authority to regulate air emissions, with the intent of enabling Pennsylvania to join the Regional Greenhouse Gas Initiative (RGGI), a multi-state regional cap-and-trade program comprised of several Eastern U.S. states. In September 2020, the EQB approved promulgation of the RGGI regulation, and a public comment period and hearings regarding the regulation commenced at the end of 2020. Based on the current timeline for implementation, final rulemaking is expected to be sent to the EQB for review and approval in the fourth quarter of 2021, with the first year of compliance anticipated to begin in 2022. Assuming Pennsylvania ultimately becomes a member of the RGGI in 2022, as currently anticipated, it will result in increased operating costs if we are required to purchase emission allowances in connection with our operations.

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, with such withdrawal becoming effective in November 2020. However, on January 20, 2021, President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which will become effective in 30 days from such date.

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 oil and natural gas we produce and lower the value of our reserves.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that natural 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, in large part driven by the fact that natural gas produces significantly less CO<sub>2</sub> compared to other fossil fuels - up to 50% less than coal and 20-30% less than oil, according to the U.S. Energy Information Administration. Nonetheless, recent activism directed at shifting funding away from fossil fuel companies could result in limitations or restrictions on certain sources of funding for the 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.

*Hydraulic Fracturing Activities.* Vast quantities of natural gas deposits exist in shale and other formations. It is customary in our 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. Our 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 our drilling locations, we conduct baseline and, as appropriate, post-drilling water testing at all water wells within at least 2,500 feet of our drilling pads.

Hydraulic fracturing typically is regulated by state oil and natural gas agencies, 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, and after a legal challenge by environmental groups, in July 2019, the EPA declined to revise the rules.

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 requirement to obtain new permits, or closure, of centralized impoundments used 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. Additionally, in January 2020, the EQB approved a well permit fee increase from \$5,000 to \$12,500 for all unconventional wells. 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.

*Occupational Safety and Health Act.* We are 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 our operations and that this information be provided to employees, state and local government authorities, and citizens.

*Endangered Species Act and Migratory Bird Treaty 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. In August 2019, the FWS and National Marine Fisheries Service issued three rules amending implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitat. A coalition of states and environmental groups have challenged the three rules and litigation remains pending. In addition, on December 18, 2020, the FWS amended its regulations governing critical habitat designations; the amended regulations are subject to ongoing litigation. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act (MBTA), which makes it illegal to, among other things, hunt, capture, kill, possess, sell, or purchase migratory birds, nests, or eggs without a permit. This prohibition covers most bird species in the U.S. In January 2021, the Department of the Interior finalized a rule limiting application of the MBTA; however, the Department of the Interior under President Biden delayed the effective date of the rule and opened a public comment period for further review. Future implementation of the rules implementing the ESA and the MBTA are uncertain. 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 development. Further, 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 limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

See Note 16 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

### **Human Capital Resources**

As of December 31, 2020, we had 624 permanent employees, none of whom were subject to a collective bargaining agreement. Of our total permanent employee base, 74% were male and 26% were female. The substantial majority of our employees reside in Pennsylvania and West Virginia.

We aim to develop a workforce that produces peer leading results. To further that goal, we have focused on creating a modern, innovative, collaborative and digitally-enabled work environment. In 2019, we simplified our organizational structure and instituted a cloud-based digital work environment with an emphasis on the democratization of data. Our digital work environment serves as our primary platform for communication and collaboration as well as the home for our critical work processes and drives decision-making based on a shared and transparent view of operational data. We use our digital work environment to engage directly with our employees by sharing company updates and personnel accomplishments and internal polling.

We understand that providing employees with the resources and support they need to live a physically, mentally, and financially healthy life is critical for sustaining a workplace of choice. We offer benefits that include subsidized health insurance, a company-contribution and company-match on 401(k) retirement savings, an employee stock purchase plan, paid maternity and paternity leave, flexible work arrangements, volunteer time off, and a company-match on employee donations to qualified non-profits. We also offer our employees the flexibility to elect to work a "9/80" work schedule, under which, during the standard 80-hour pay period, an employee works eight 9-hour days and one 8-hour day (Friday), with a tenth day off (alternative Friday).

In 2020, we launched an "equity-for-all" program, which granted equity awards to all of our permanent full-time employees. With the equity-for-all program, all of our permanent full-time employees have the opportunity to share directly in our financial success. These grants were in addition to, and not in lieu of, existing compensation for these employees.

### **Availability of Reports and Other Information**

We make certain filings with the SEC, including our 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 our investor relations website, <http://ir.eqt.com>, as soon as reasonably practicable after they are filed with or furnished to the SEC. Reports filed with the SEC are also available on the SEC's website, <http://www.sec.gov>.

We also use our Twitter account, @EQTCorp, our Facebook account, @EQTCorporation, and our LinkedIn account, EQT Corporation, as additional ways of disseminating information that may be relevant to investors.

We generally post the following to our investor relations website shortly before or promptly following its first use or release: financially-related press releases, including earnings releases and supplemental financial information; various SEC filings; presentation materials associated with earnings and other investor conference calls or events; and access to live and recorded audio from earnings and other investor conference calls or events. In certain cases, we may post the presentation materials for other investor conference calls or events several days prior to the call or event. For earnings and other conference calls or events, we generally include within our posted materials a cautionary statement regarding forward-looking and non-GAAP financial information as well as non-GAAP to GAAP financial information reconciliations (if available). Such GAAP reconciliations may be in materials for the applicable presentation, in materials for prior presentations or in our annual, quarterly or current reports.

In certain circumstances, we may post information, such as presentation materials and press releases, to our corporate website, [www.EQT.com](http://www.EQT.com), or our investor relations website to expedite public access to information regarding EQT in lieu of making a filing with the SEC for first disclosure of the information. When permissible, we expect to continue to do so without also providing disclosure of this information through filings with the SEC.

Where we have included internet addresses in this Annual Report on Form 10-K, we have included those internet addresses as inactive textual references only. Except as specifically incorporated by reference into this Annual Report on Form 10-K, information on those websites is not part hereof.

## Composition of Operating Revenues

The following table presents total operating revenues for each class of our products and services.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Operating revenues:			
Sales of natural gas, NGLs and oil	\$ 2,650,299	\$ 3,791,414	\$ 4,695,519
Gain (loss) on derivatives not designated as hedges	400,214	616,634	(178,591)
Net marketing services and other	8,330	8,436	40,940
Total operating revenues	<u>\$ 3,058,843</u>	<u>\$ 4,416,484</u>	<u>\$ 4,557,868</u>

## Jurisdiction and Year of Formation

We are a Pennsylvania corporation formed in 2008 in connection with a holding company reorganization of the former Equitable Resources, Inc.

## 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. 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.

### Summary of Risk Factors

We believe that the risks associated with our business, and consequently the risks associated with an investment in our equity or debt securities, fall within the following six categories:

- **Risks Associated with Natural Gas Drilling Operations.** As a natural gas producer, there are risks inherent in our primary business operations. These risks are not necessarily unique to us, but rather, these are risks that most operators in our industry have at least some exposure to.
- **Financial and Market Risks.** Given that our primary product and source of revenue is the sale of natural gas and NGLs, one of our most material risks is the commodity market and the price of natural gas and NGLs, which is often volatile. Additionally, our operations are capital intensive. Pressures on the market as a whole, or our specific financial

position – whether due to depressed commodity prices, our leverage, our credit ratings or otherwise – could make it difficult for us to obtain the funding necessary to conduct our operations.

- **Risks Associated with Our Human Capital, Technology and Other Resources and Service Providers.** Our business, and the U.S. energy grid, is predominately operated on a digital system. Our employees rely on our cloud-based digital work environment to communicate and access data that is necessary to conduct our day-to-day operations. While these digital systems enable us to efficiently supply our natural gas and NGLs to the market, they are also susceptible to cyber security threats. Likewise, as a digitally-focused organization, we seek employees with a high degree of both technical skill and digital literacy, and it can be difficult to attract and retain personnel who satisfy these criteria. Further, we predominately operate in the Appalachia Basin, and a substantial majority of our midstream and water services are provided by one provider, EQM Midstream Partners, LP, making us vulnerable to risks associated with operating primarily in one major geographic area and obtaining a substantial amount of our services from a single provider within that operating area.
- **Legal and Regulatory Risks.** There are many environmental, energy, financial, real property and other regulations that we are required to comply with in the context of conducting our operations, otherwise, we may be exposed to fines, penalties, investigations, litigation or other legal proceedings. Additionally, negative public perception of us or the natural gas industry, or increasing consumer demand for alternatives to natural gas, could adversely impact our earnings, cash flows and financial position.
- **Risks Associated with Strategic Transactions.** We have historically been involved in, and anticipate that we will continue to explore, opportunities to create value through strategic transactions, whether through mergers and acquisitions, divestitures, joint ventures or similar business transactions. There are risks inherent in any strategic transaction, and such risks could negatively affect the benefits, outcomes and synergies anticipated to be obtained from executing such strategic transactions.
- **Risks Related to the COVID-19 Pandemic.** While we did not experience any material adverse effects from the COVID-19 pandemic in 2020, the severity, magnitude and duration of the COVID-19 pandemic is still uncertain, rapidly changing and difficult to predict. We believe that our principal areas of operational risk resulting from a pandemic are availability of service providers and supply chain disruption. Additionally, active development operations, including drilling and fracking operations, represent the greatest risk for transmission given the number of personnel and contractors on our drilling sites. We believe that we are following best practices under COVID-19 guidance; however, the potential for transmission still exists, and in certain instances, it may be necessary or determined advisable for us to delay our development operations.

We describe these risks in greater detail below.

### **Risks Associated with Natural Gas Drilling Operations**

**Drilling for and producing natural gas is a high-risk and costly activity 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 production or that we will not recover all or any portion of our investment in drilled wells.**

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 and water facilities or delays in construction of gathering and water facilities;
- lack of available capacity on interconnecting transportation 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 and diesel 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 financial losses, 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.

**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 and diesel 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.

**Our drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of when they are drilled, if at all.**

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.

**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. Approximately 16% 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 that we have not developed.

We evaluate capitalized costs of unproved oil and gas properties at least annually to determine 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, 2020, 2019 and 2018, we recorded lease impairments and expirations of \$306.7 million, \$556.4 million and \$279.7 million, respectively. Refer to Note 1 to the Consolidated Financial Statements.

**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.

**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 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 on 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.

**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 crude 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 crude 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 our operations or the natural gas, NGLs and oil industry in general.

**Natural gas, NGLs and oil price declines, and changes in our development strategy, have resulted in impairment of certain of our assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance or additional changes in our development strategy 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 review the carrying values of our proved oil and gas properties for indications of impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. 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 used 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 that 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.

Future declines in natural gas, NGLs or oil prices, increases in operating costs or adverse changes in well performance, among other circumstances, 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" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations."

#### **Financial and Market Risks Applicable to Our Business**

**Natural gas, NGLs and oil price volatility, or a prolonged period of low natural gas, NGLs and oil prices, may have an adverse effect on 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 and, to a lesser extent, 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 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 \$3.14 per MMBtu to a low of \$1.33 per MMBtu from January 1, 2020 through December 31, 2020, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of \$63.27 per barrel to a low of \$(36.98) 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 significant increases in the supply of natural gas in the Northeast United States. Because our production and reserves predominantly consist of natural gas (approximately 93% 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, NGLs and oil at our 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. 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" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations." We are also exposed to the risk 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 will not benefit fully from an increase in the price of natural gas.

**We may not be able to successfully execute our plan to deleverage our business or otherwise reduce our debt level.**

In an effort to improve our leverage ratio, in the fourth quarter of 2019, we announced a plan to reduce our absolute debt using free cash flow and targeted proceeds from the monetization of select, non-strategic exploration and production assets, core mineral assets and our remaining retained equity interest in Equitrans Midstream (the Deleveraging Plan). There can be no

assurance that we will be able to generate sufficient free cash flow or find attractive asset monetization opportunities or that any such transactions will be completed on our anticipated timeframe, if at all, which would delay or inhibit our ability to successfully execute our Deleveraging Plan. Furthermore, our estimated value for the assets to be monetized under our Deleveraging Plan involves multiple assumptions and judgments about future events that are inherently uncertain; accordingly, there can be no assurance that the resulting net cash proceeds from asset monetization transactions will be as anticipated, even if such transactions are consummated. Some of the factors that could affect our ability to successfully execute our Deleveraging Plan include changes in the financial condition or prospects of prospective purchasers and the availability of financing to potential purchasers on reasonable terms, the number of prospective purchasers, the number of competing assets on the market, unfavorable economic conditions, industry trends and changes in laws and regulations. If we are not able to successfully execute our Deleveraging Plan or otherwise reduce our absolute debt to a level we believe appropriate, our credit ratings may be lowered, we may reduce or delay our planned capital expenditures or investments, and we may revise or delay our strategic plans.

**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 credit facility and other external sources of capital. If we do not have sufficient borrowing availability under our credit facility, 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 credit facility.

If our cash flows from operations or the borrowing capacity under our 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.

As of December 31, 2020, our senior notes were rated "Ba3" with a "positive" outlook by Moody's Investors Services (Moody's), "BB" with a "stable" outlook by Standard & Poor's Ratings Service (S&P) and "BB" with a "positive" outlook by Fitch Ratings Service (Fitch). Although we are not aware of any current plans of Moody's, S&P or Fitch to downgrade its rating of our senior notes, we cannot be assured that one or more of these rating agencies will not downgrade or withdraw entirely its rating of our senior notes. Low prices for natural gas, NGLs and oil, an increase in the level of our indebtedness or a failure to significantly execute our Deleveraging Plan may result in Moody's, S&P or Fitch downgrading its rating of our senior notes. Changes in credit ratings may affect our access to the capital markets, the cost of short-term debt through interest rates and fees under our lines of credit, the interest rate on the Adjustable Rate Notes (defined in Note 10 to the Consolidated Financial Statements), the rates available on new long-term debt, our pool of investors and funding sources, the borrowing costs and margin deposit requirements on our OTC derivative instruments and credit assurance requirements, including collateral, in support of our midstream service contracts, joint venture arrangements or construction contracts.

**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, 2020, we had approximately \$4,925 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, 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 flows 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 credit facility to the extent that one or more of our lenders may be unable to provide necessary funding to us under our existing line of credit if it experiences liquidity problems.

**Uncertainty related to the LIBOR calculation process and potential phasing out of LIBOR after 2021 may adversely affect the market value of our current or future debt obligations.**

Loans to us under our credit facility may be base rate loans or LIBOR loans. LIBOR is calculated by reference to a market for interbank lending, and it is based on increasingly fewer actual transactions. This increases the subjectivity of the LIBOR calculation process and increases the risk of manipulation. Actions by the regulators or law enforcement agencies, as well as ICE Benchmark Administration (the current administrator of LIBOR), may result in changes to the manner that LIBOR is determined or the establishment of alternative reference rates. For example, on July 27, 2017, the U.K. Financial Conduct Authority announced that it intends to stop persuading or compelling banks to submit LIBOR rates after 2021. U.S. Dollar LIBOR will likely be replaced by the Secured Overnight Financing Rate (SOFR) published by the Federal Reserve Bank of New York; however, the timing of this shift is currently unknown. SOFR is an overnight rate instead of a term rate, making SOFR an inexact replacement for LIBOR, and there is not an established process to create robust, forward-looking, SOFR term rates. Changing the benchmark rate for LIBOR loans from LIBOR to SOFR requires calculations of a spread. Industry organizations are attempting to structure the spread calculation in a manner that minimizes the possibility of value transfer between counterparties, borrowers, and lenders by the transition, but there is no assurance that the calculated spread will be fair and accurate. At this time, it is not possible to predict the effect of any such changes, any establishment of alternative reference rates or any other reforms to LIBOR that may be implemented. If LIBOR ceases to exist, we may need to renegotiate our credit facility to determine the interest rate to replace LIBOR with the new standard that is established. As such, the potential effect of any such event on our interest expense cannot yet be determined.

**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 in order 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 derivative contracts fail to perform on their contract obligations; or
- 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.

**The accounting for the Convertible Notes may have a material effect on our reported financial results.**

On April 28, 2020, we issued the Convertible Notes (defined in Note 10 to the Consolidated Financial Statements) due May 1, 2026 unless earlier redeemed, repurchased or converted. In accordance with GAAP, an issuer must separately account for the liability and equity components of certain convertible debt instruments that may be settled entirely or partially in cash upon conversion in a manner that reflects the issuer's economic interest cost. The effect on the accounting for the Convertible Notes is that the equity component is required to be included in additional paid-in capital of shareholders' equity on our Condensed Consolidated Balance Sheet, and the value of the equity component is treated as a debt discount for purposes of accounting for the debt component of the Convertible Notes. Accordingly, we will be required to record a greater amount of non-cash interest expense in current and future periods as a result of the amortization of the discounted carrying value of the Convertible Notes to their face amount over the term of the Convertible Notes. We will report lower net income (or greater net loss) in our financial results because GAAP requires interest to include both the current period's amortization of the debt discount and the instrument's coupon interest, which could adversely affect our reported or future financial results, the market price of our common stock and the trading price of the Convertible Notes.

In addition, because we have the ability and intent to settle the Convertible Notes, upon conversion, by paying or delivering cash equal to the principal amount of the obligation and common stock for amounts over the principal amount, the shares issuable upon conversion of the Convertible Notes are accounted for using the treasury stock method and, as such, are not included in the calculation of diluted earnings per share except to the extent that the conversion value of the Convertible Notes exceeds their principal amount. Further, under the treasury stock method, the transaction is accounted for as if the number of shares of common stock that would be necessary to settle such excess are issued. We cannot be sure that we will be able to continue to demonstrate the ability or intent to settle in cash or that the accounting standards will continue to permit the use of the treasury stock method. If we are unable to use the treasury stock method in accounting for the shares issuable upon conversion of the Convertible Notes, our diluted earnings per share could be adversely affected.

**Risks Associated with Our Human Capital, Technology and Other Resources and Service Providers**

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

Our future prospects are dependent upon our ability to identify optimal strategies for our business. Our operational strategy focuses on developing several multi-well pads in tandem through a process known as combo-development. We have allocated a

substantial portion of our financial, human capital and other resources to pursuing this strategy, including investing in new technologies and equipment, restructuring our workforce, and pursuing various ESG initiatives geared towards enhancing our strategy. We may not realize some or any of the anticipated strategic, financial, operational, environmental and other anticipated benefits from our operational strategy and the corresponding investments we have made in pursuing our strategy. Additionally, we cannot be certain that we will be able to successfully execute combo-development projects at the pace and scale that we project, which may delay or reduce our production and our reserves, negatively affecting our associated revenues. If we fail to identify and successfully execute optimal business strategies, including the appropriate operational strategy and corresponding initiatives, or fail to optimize our capital investments and the use of our other resources in furtherance of optimal business strategies, our financial position and growth 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.

**Cyber incidents targeting our digital work environment or other technologies 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 oil reserves, analyze and share operating data and communicate internally and externally. Computers and mobile devices 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 digital work environment or other technologies and 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.

**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 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 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.

**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.

**We depend on third-party midstream providers 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 on competitive terms 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 at competitive rates or at all. 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.

We are dependent on third-party providers to provide us with access to midstream infrastructure 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. 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 third-party pipelines and facilities for any reason, including vandalism, terroristic acts, 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.

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 use the capacity we have reserved, and these payments may be significant.

**The substantial majority of our midstream and water services are provided by one provider, EQM Midstream Partners LP (EQM), a wholly-owned subsidiary of Equitrans Midstream. Therefore, any regulatory, infrastructure, or other events that materially adversely affect EQM's business operations will have a disproportionately adverse effect on our business and operating results as compared to similar events experienced by our other third-party service providers. Additionally, our midstream services contracts with EQM involve significant long-term financial and other commitments on our part, which hinders our ability to diversify our slate of midstream service providers and seek better economic and other terms for the midstream services that are provided to us. We have no control over Equitrans Midstream's or EQM's business decisions and operations, and neither Equitrans Midstream nor EQM is under any obligation to adopt a business strategy that favors us.**

Historically, we have received the substantial majority of our natural gas gathering, transmission and storage and water services from EQM. Additionally, on February 26, 2020, we executed a new gas gathering agreement with EQM (the Consolidated

GGA), which, among other things, consolidated the majority of our prior gathering agreements with EQM into a single agreement, established a new fee structure for gathering and compression fees charged by EQM, increased our minimum volume commitments with EQM, committed certain of our remaining undedicated acreage to EQM and extended our and EQM's contractual obligations with each other to 2035. Because we have significant long-term contractual commitments with EQM, we expect to receive the majority of our midstream and water services from EQM for the foreseeable future. Therefore, any event, whether in our areas of operation or otherwise, that adversely affects EQM's operations, water assets, pipelines, other transportation facilities, gathering and processing facilities, financial condition, leverage, results of operations or cash flows will have a disproportionately adverse effect on our business and operating results as compared to similar events experienced by our other third-party service providers. Accordingly, we are subject to the business risks of EQM, including the following:

- federal, state and local regulatory, political and legal actions that could adversely affect EQM's operations, assets and infrastructure, including potential further delays associated with obtaining regulatory approval for the construction of the Mountain Valley Pipeline and the MVP Southgate project;
- construction risks associated with the construction or repair of EQM's pipelines and other midstream infrastructure, such as delays caused by landowners or advocacy groups opposed to the natural gas industry, environmental hazards, adverse weather conditions, the performance of third-party contractors, the lack of available skilled labor, equipment and materials and the inability to obtain necessary rights-of-way or approvals and permits from regulatory agencies on a timely basis or at all (and maintain such rights-of-way, approvals and permits once obtained);
- acts of cybersecurity, sabotage or terrorism that could cause significant damage or injury to EQM's personnel, assets or infrastructure or lead to extended interruptions of EQM's operations;
- risks associated with EQM failing to properly balance supply and demand for its services, on a short-term, seasonal and long-term basis, which could result in EQM being unable to provide its customers, including us, with sufficient access to pipeline and other midstream infrastructure and water services as needed; and
- risks associated with EQM's leverage and financial profile, which could result in EQM being financially deterred or prohibited from providing services to its customers, including us, on a timely basis or at all.

In addition, many of our midstream services obligations with EQM are "firm" commitments, under which we have reserved an agreed upon amount of pipeline or storage capacity with EQM regardless of the capacity that we actually use during each month, and we are generally obligated to pay a fixed, monthly charge, at an amount agreed upon in the contract. Because these obligations involve significant long-term financial and other commitments on our part, they could reduce our cash flow during periods of low prices for natural gas, NGLs and oil when we may have lower volumes of natural gas and NGLs and therefore less of a need for capacity and storage, or the market prices for such pipeline and storage capacity services may be lower than what we are contractually obligated to pay to EQM.

Further, the Consolidated GGA provides for a reduced fee structure for the gathering and compression fees charged by EQM; however this new fee structure does not take effect until the Mountain Valley Pipeline's in-service date. There can be no assurance that the in-service date of the Mountain Valley Pipeline will not be delayed, or that the project will not be cancelled entirely, which would consequently delay, possibly indefinitely, the effective date of the fee reductions contemplated in the Consolidated GGA. Neither Equitrans Midstream nor EQM is under any obligation to renegotiate their contracts with us, including the Consolidated GGA, in the event of a prolonged depressed commodity price environment or if the Mountain Valley Pipeline's in-service date is delayed. We have recorded in our Consolidated Balance Sheet a contract asset of \$410 million representing the estimated fair value of the rate relief provided by the Consolidated GGA that would be realized beginning with the Mountain Valley Pipeline's in-service date. We review the contract asset for indications of impairment when events or circumstances indicate the carrying value may not be recoverable. Although the Consolidated GGA provides a cash payment option that grants us the right to receive payments from EQM in the event that the Mountain Valley Pipeline in-service date has not occurred prior to January 1, 2022, future delays in the Mountain Valley Pipeline's in-service date may nonetheless affect our ability to fully realize the value we recorded as a contract asset for the rate relief associated with the Consolidated GGA, which could adversely affect our results of operations in future periods.

**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 natural gas,

NGLs or oil 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 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.

### **Legal and Regulatory Risks**

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

Opposition toward oil and natural gas drilling and development activities generally has been growing globally and is particularly pronounced in the U.S., and companies in our industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, human rights, environmental matters, sustainability and business practices. Negative public perception regarding us and/or our industry 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. In addition, anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain operations, such as drilling and development. If activism against oil and natural gas exploration and development persists or increases, there could be a material adverse effect on our business, financial condition and results of operations.

#### **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 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.

**Changes in tax laws and regulations could adversely impact our earnings and the cost, manner or feasibility of conducting our operations.**

Effective January 1, 2018, changes to certain U.S. federal income tax laws were signed into law that impact us, including but not limited to: changes to the regular income tax rate; the elimination of the alternative minimum tax (AMT); full expensing of capital equipment; limited deductibility of interest expense; and increased limitations on deductible executive compensation. On March 27, 2020, the U.S. Congress enacted the Coronavirus Aid, Relief, and Economic Security Act (CARES Act), which, among other things, includes provisions relating to net operating loss (NOL) carryback periods, AMT credit refunds and modifications to the net interest deduction limitations. In particular, under the CARES Act, (i) for taxable years beginning before 2021, NOL carryforwards and carrybacks may offset 100% of taxable income, (ii) NOLs arising in 2018, 2019, and 2020 taxable years may be carried back to each of the preceding five years to generate a refund, and (iii) for taxable years beginning in 2019 and 2020, the base for interest deductibility is increased from 30% to 50% of EBITDA.

Members of Congress periodically introduce legislation to revise U.S. federal income tax laws which could have a material impact on us. The most significant potential tax law changes that could impact us include increases in the regular income tax rate, a new minimum tax based on net income, the expensing of intangible drilling costs or percentage depletion, the repeal of like-kind exchange tax deferral rules on real property 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.

**Our hedging activities are subject to numerous and evolving financial laws and regulations which could inhibit our ability to effectively hedge our production against commodity price risk or increase our cost of compliance.**

We use financial derivative instruments to hedge the impact of fluctuations in natural gas, NGLs and oil prices on our results of operations and cash flows. In 2010, Congress adopted the Dodd-Frank Act, which established federal oversight and regulation of the OTC derivative market and entities, such as us, that participate in that market. The Dodd-Frank Act required the CFTC, the SEC and certain federal agencies that regulate the banking and insurance sectors (Prudential Regulators) to promulgate rules and regulations implementing the legislation. Among other things, the Dodd-Frank Act established margin requirements and requires clearing and trade execution practices for certain categories of swaps and may result in certain market participants needing to curtail their derivative activities. Although some of the rules necessary to implement the Dodd-Frank Act have yet to be adopted, the CFTC, the SEC and Prudential Regulators have issued numerous rules, including the End-User Exception, which exempts certain “end-users” from having to comply with mandatory clearing, a Margin Rule mandating margining for certain uncleared swaps, and a Position Limits Rule imposing federal position limits on certain futures contracts relating to energy products, including natural gas.

We qualify as a “non-financial entity” for purposes of the End-User Exception and, as such, we are eligible for such exception. As a result, our hedging activities are not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing, although we are subject to certain recordkeeping and reporting obligations associated with such rule. We also qualify as a “non-financial end user” for purposes of the Margin Rule; therefore, our uncleared swaps are not subject to regulatory margin requirements. Finally, although the Position Limits Rule does not go into effect with respect to energy products until January 1, 2022, we believe that the majority, if not all, of our hedging activities constitute bona fide hedging under the Position Limits Rule and will not be subject to the limitations under such rule. However, many of our hedge counterparties and other market participants are not eligible for the End-User Exception, are subject to mandatory clearing and the Margin Rule for swaps with some or all of their other swap counterparties, and may be subject to the Position Limits Rule, which may affect the pricing and/or availability of derivatives for us. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations related to derivatives (collectively, Foreign Regulations) which apply to our transactions with counterparties subject to such Foreign Regulations.

The Dodd-Frank Act, the rules adopted thereunder and the Foreign Regulations could increase the cost of our derivative contracts, alter the terms of our derivative contracts, reduce the availability of derivatives to protect against the price risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, lessen the number of available counterparties and, in turn, increase our exposure to less creditworthy counterparties. If our use of derivatives is reduced as a result of the Dodd-Frank Act, related regulations or the Foreign Regulations, our results of operations may become more volatile, and our cash flows may be less predictable, which could adversely affect our ability to plan for, and fund, our capital expenditure requirements. Any of these consequences could have a material and adverse effect on our business, financial position and results of operations. We have experienced increased, and anticipate additional, compliance costs and changes to current market practices as participants continue to adapt to a changing financial 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 use hydraulic fracturing in the completion of our 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 finalized rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants, and after a legal challenge by environmental groups, in July 2019, the EPA declined to revise the rules.

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 June 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, which was stayed nationwide in October 2015 pending resolution of several legal challenges. The EPA and the Corps proposed a rule in July 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, which lifted the stay and resulted in a patchwork application of the rule in some states, but not in others. In October 2019, the EPA issued a final rule repealing the WOTUS rule and the repeal rule became effective in December 2019. In April 2020, the EPA and the Corps published the NWPR, which narrows the definition of WOTUS to four categories of jurisdictional waters and includes twelve categories of exclusions, including groundwater. A coalition of states and cities, environmental groups, and agricultural groups have challenged the NWPR and a federal district court in Colorado stayed implementation of the rule. The stay is limited to application of the rule in Colorado; the rule has taken effect in all other states. In addition, in an April 2020 decision defining the scope of the CWA that was handed down just days after the NWPR was published, the U.S. Supreme Court held that, in certain cases, discharges from a point source to groundwater could fall within the scope of the CWA and require a permit. The Court rejected the EPA and Corps' assertion that groundwater should be totally excluded from the CWA. The Court's decision is expected to bolster challenges to the NWPR. On January 20, 2021, the Biden Administration announced it will review the NWPR in accordance with the January 20, 2021 Executive Order that revokes President Trump's Executive Order 13778, which required review and reversal of the WOTUS rule. The EPA and the Corps have requested to stay the litigation over the NWPR during the agencies' review of the rule. To the extent a 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.

**Fuel conservation measures, consumer tastes 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. In October 2019, Pennsylvania Governor Tom Wolf signed an Executive Order directing the PADEP to draft regulations establishing a cap-and-trade program under its existing authority to regulate air emissions, with the intent of enabling Pennsylvania to join the RGGI, a multi-state regional cap-and-trade program comprised of several Eastern U.S. states. In September 2020, the Pennsylvania Environmental Quality Board approved promulgation of the RGGI regulation, and a public comment period and hearings regarding the regulation commenced at the end of 2020. Based on the current timeline for implementation, final rulemaking is expected to be sent to the Pennsylvania Environmental Quality Board for review and approval in the fourth quarter of 2021, with the first year of compliance anticipated to begin in 2022. Assuming Pennsylvania ultimately becomes a member of the RGGI in 2022, as currently anticipated, it will result in increased operating costs if we are required to purchase emission allowances in connection with our operations.

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, with such withdrawal becoming effective in November 2020. However, on January 20, 2021, President Biden issued written notification to the United Nations of the United States' intention to rejoin the Paris Agreement, which will become effective in 30 days from such date.

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.

Further, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. 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.

### **Risks Associated with Strategic Transactions**

#### **Entering into 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 these 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.**

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.

**The Separation and Distribution may subject us to future liabilities.**

In November 2018, we completed the Separation and Distribution (each defined and discussed in Note 8 to the Consolidated Financial Statements), resulting in the spin-off of Equitrans Midstream, a standalone publicly traded corporation that 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, significant liabilities could be incurred by us, our shareholders or Equitrans Midstream.**

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

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

Following the Separation and Distribution, we retained approximately 19.9% of the outstanding shares of Equitrans Midstream's common stock. On February 26, 2020, we entered into share purchase agreements with Equitrans Midstream to sell approximately 50% of our equity interest in Equitrans Midstream to Equitrans Midstream (the Equitrans Share Exchange) in exchange for a combination of cash and fee relief under our gathering agreements with EQM. We currently own 25,296,026 shares of Equitrans Midstream's common stock. 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, pipeline safety rulemakings initiated or finalized by the Department of Transportation's Pipeline and Hazardous Materials Safety Administration, 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 remaining interest in Equitrans Midstream through one or more divestitures of our shares of Equitrans Midstream's common stock. 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.

**Risks Related to the COVID-19 Pandemic**

**The novel coronavirus, or COVID-19, pandemic has affected and may materially adversely affect, and any future outbreak of any other highly infectious or contagious diseases may materially adversely affect, our operations, financial performance and condition, operating results and cash flows.**

The COVID-19 pandemic has affected, and may materially adversely affect, our business and financial and operating results. The severity, magnitude and duration of the COVID-19 pandemic is uncertain, rapidly changing and hard to predict. In 2020, the pandemic significantly impacted economic activity and markets around the world, and, in the future, COVID-19 or another similar pandemic could negatively impact our business in numerous ways, including, but not limited to, the following:

- our revenue may be reduced if the pandemic results in an economic downturn or recession that leads to a prolonged decrease in the demand for natural gas and, to a lesser extent, NGLs and oil;
- our operations may be disrupted or impaired (thus lowering our production level), if a significant portion of our employees or contractors are unable to work due to illness or if our field operations are suspended or temporarily shut-down or restricted due to control measures designed to contain the pandemic;
- the operations of our midstream service providers, on whom we rely for the transmission, gathering and processing of a significant portion of our produced natural gas, NGLs and oil, may be disrupted or suspended in response to containing the pandemic, and/or the difficult economic environment may lead to the bankruptcy or closing of the facilities and infrastructure of our midstream service providers, which may result in substantial discounts in the prices

we receive for our produced natural gas, NGLs and oil or result in the shut-in of producing wells or the delay or discontinuance of development plans for our properties; and

- the disruption and instability in the financial markets and the uncertainty in the general business environment may affect our ability to raise capital or find attractive asset monetization opportunities and successfully execute our Deleveraging Plan within our anticipated timeframe or at all.

We believe that our principal areas of operational risk resulting from a pandemic are availability of service providers and supply chain disruption. Active development operations, including drilling and fracking operations, represent the greatest risk for transmission given the number of personnel and contractors on site. While we believe that we are following best practices under COVID-19 guidance, the potential for transmission still exists. In certain instances, it may be necessary or determined advisable for us to delay development operations.

To the extent the COVID-19 pandemic adversely affects our business and financial results, it may also have the effect of heightening many of the other risks set forth herein, such as those relating to our financial performance, our ability to access capital and credit markets, our credit ratings and debt obligations. The rapid development and fluidity of this situation precludes any prediction as to the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments that we are not able to predict, including the length of time that the pandemic continues, its effect on the demand for natural gas, NGLs and oil, the response of the overall economy and the financial markets as well as the effect of governmental actions taken in response to the pandemic.

**See Item 7A., "Quantitative and Qualitative Disclosures About Market Risk" for further discussion of our exposure to market risks, including the risks associated with our use of derivative contracts to hedge commodity prices.**

#### **Item 1B. Unresolved Staff Comments**

None.

#### **Item 2. Properties**

See Item 1., "Business" for a description of our properties. Our corporate headquarters is located in leased office space in Pittsburgh, Pennsylvania. We also own or lease office space in Pennsylvania, West Virginia, Ohio, Virginia and Texas.

#### **Item 3. Legal Proceedings**

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against us. While the amounts claimed may be substantial, we are unable to predict with certainty the ultimate outcome of such claims and proceedings. We accrue legal and other direct costs related to loss contingencies when actually incurred. We have established reserves in amounts that we believe to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, we believe that the ultimate outcome of any matter currently pending against us will not materially impact our financial position, results of operations or liquidity.

#### ***Environmental Proceedings***

*Produced Water Release, Marshall County, West Virginia.* On November 12, 2019, we received a Notice of Violation (NOV) from the West Virginia Department of Environmental Protection (WVDEP) relating to the Goshorn Pad in Marshall County, West Virginia. The NOV alleged violations of Water Pollution Control Rules in connection with a release of produced water from secondary containment at a Goshorn Pad tank battery. We cooperated fully with WVDEP to take appropriate actions to address the secondary containment issues and remediation of the release, and this matter was substantially resolved in March 2020. We were not assessed any monetary penalty for this matter, and the resolution of this matter did not have a material impact on our financial position, results of operations or liquidity.

*Secondary Containment underneath Gas Processing Units (GPUs), Allegheny, Greene and Washington Counties, Pennsylvania.* On April 1, 2020, we received a draft Consent Order and Agreement from the Pennsylvania Department of Environmental Protection (PADEP) claiming that we failed to install secondary containment systems in accordance with 25 Pa. Code § 78a.64a(b) underneath 228 GPUs located in southwest Pennsylvania between October 8, 2016 and February 4, 2019. On February 4, 2019, we voluntarily disclosed a list of GPUs that did not meet the requirements of 25 Pa. Code § 78a.64a(b). On December 17, 2020, we entered into the Consent Order and Agreement with PADEP, pursuant to which we agreed to install

secondary containment systems in compliance with 25 Pa. Code § 78a.64a(b) on all new GPU installations going forward, among other things, and this matter was resolved. We were not assessed any monetary penalty for this matter, and the resolution of this matter did not have a material impact on our financial position, results of operations or liquidity.

#### **Other Legal Proceedings**

*Mary Farr Secrist, et al. v. EQT Production Company, et al., Circuit Court of Doddridge County, West Virginia.* On May 2, 2014, royalty owners whose predecessors had entered into a 960-acre lease (the Stout Lease) and several additional leases comprising 6,356-acres (the Cities Services Lease) with EQT Production Company's predecessor, each covering acreage in Doddridge County, West Virginia, filed a complaint in the Circuit Court of Doddridge County, West Virginia. The complaint alleged that EQT Production Company and a number of related companies, including EQT Corporation, EQT Gathering, LLC, EQT Energy, LLC, and EQM Midstream Services, LLC (formerly known as EQT Midstream Services, LLC, the general partner of our former midstream affiliate), underpaid on royalties for gas produced under the leases and took improper post-production deductions from the royalties paid. With respect to the Stout Lease, the plaintiffs also asserted that we committed a trespass by drilling on the leased property, claiming that we had no right under the lease to drill in the Marcellus Shale formation. The plaintiffs also asserted claims for fraud, slander of title, punitive damages, pre-judgment interest and attorneys' fees. The plaintiffs sought more than \$100 million in compensatory damages for the trespass claim under the Stout Lease, and approximately \$20 million for insufficient royalties under both the Stout Lease and the Cities Services Lease, in addition to punitive damages and other relief. On June 27, 2018, the Court held that EQT Production Company and its marketing affiliate EQT Energy, LLC are alter egos of one another and that royalties paid under the leases should have been based on the price of gas produced under the leases when sold to unaffiliated third parties, and not on the price when the gas was sold from EQT Production Company to EQT Energy, LLC. Further, on January 14, 2019, the Court entered an Order granting the plaintiffs' motion for summary judgment and declaring that we did not have the right to drill in the Marcellus Shale formation under the Stout Lease. The Court also ruled that seven of our wells that have been producing gas under the Stout Lease are trespassing, and that a jury will determine whether the trespass was willful or innocent. On February 27, 2019, we filed a motion seeking permission to immediately appeal the trespass Order to the West Virginia Supreme Court; however, the motion was denied on March 25, 2019, and the Court continued the trial to September 2019. On May 28, 2019, the Court entered an Order excluding certain of our costs that could have otherwise offset any damages for innocent trespass under the Stout Lease. On August 8, 2019, we reached a settlement with the plaintiffs to resolve all claims under the Stout Lease and the Cities Services Lease for \$54 million plus lease modifications to address the trespass issue and the calculation of future royalty payments under the leases. We paid \$51 million of the settlement in October 2019 and the remaining \$3 million of the settlement in January 2020, and the Stout Lease was subsequently amended to address the terms agreed to with the plaintiffs under the settlement. On October 7, 2020, the plaintiffs filed a motion to amend their complaint and to stay entry of an Order of Dismissal. On January 14, 2021, we filed a motion to enforce the settlement agreed to with the plaintiffs and to seek sanctions. All recent motions are pending.

*Hammerhead Gathering Agreement Dispute.* EQT Corporation and Equitrans Midstream, through certain of our and their subsidiaries, are parties to a gas gathering agreement (the Hammerhead Gathering Agreement) related to Equitrans Midstream's Hammerhead Gas Gathering System. Pursuant to the terms of the Hammerhead Gathering Agreement, if the "In-Service Date" did not occur on or before October 1, 2020, we may terminate the Hammerhead Gathering Agreement and purchase the Hammerhead Gas Gathering System from Equitrans Midstream for an amount equal to 88% of expenses actually incurred and other obligations made or to be incurred by Equitrans Midstream. The "In-Service Date" is defined in the Hammerhead Gathering Agreement as "the later of (i) the first Day of the Month immediately following the date on which Gatherer is first able to provide the Gathering Services to Shipper in accordance with the Hammerhead Gathering Agreement and (ii) the first Day of the Month immediately following the date on which the Interconnect Facilities connecting the Gathering System to the Mountain Valley Pipeline are first able to receive deliveries of the Contract MDQ." On September 24, 2020, we initiated arbitration proceedings against Equitrans Midstream, seeking a declaration that we are entitled to terminate the Hammerhead Gathering Agreement and purchase the Hammerhead Gas Gathering System. The deadline for us to provide notice of our election to terminate the Hammerhead Gathering Agreement and purchase the Hammerhead Gas Gathering System has been tolled while the contract claim is pending in arbitration.

#### **Item 4. Mine Safety Disclosures**

Not Applicable.

**Information about our Executive Officers (as of February 17, 2021)**

<b>Name and Age</b>	<b>Current Title (Year Initially Elected an Executive Officer)</b>	<b>Business Experience</b>
Tony Duran (42)	Chief Information Officer (2019)	Mr. Duran was appointed as the Chief Information Officer of EQT Corporation in July 2019. Prior to joining EQT Corporation, Mr. Duran ran PH6 Labs, a technology incubator he founded, from December 2017 to July 2019. Prior to that, he served as the Chief Information Officer of Rice Energy Inc. (independent natural gas and oil company acquired by EQT Corporation in November 2017) from January 2016 to November 2017; and as the Interim Chief Information Officer of Express Energy Services (oilfield services company for well construction and well testing services) from September 2015 to December 2015. Additionally, Mr. Duran held various positions at National Oilwell Varco (multinational corporation that provides equipment and components used in oil and gas drilling and production operations, oilfield services, and supply chain integration services to the upstream oil and gas industry) from May 2002 to August 2015, where he last held the role of Assistant Chief Information Officer.
Lesley Evancho (43)	Chief Human Resources Officer (2019)	Ms. Evancho was appointed as the Chief Human Resources Officer of EQT Corporation in July 2019. Prior to joining EQT Corporation, Ms. Evancho served as Vice President, Global Talent Management at Westinghouse Electric Company, LLC (nuclear power, fuel and services company) from April 2019 to July 2019; Senior Director, Human Resources at Thermo Fisher Scientific, Inc. (biotechnology product development company) from August 2018 to March 2019; Vice President, Human Resources at Edward Marc Brands (food services company) from March 2018 to August 2018; and Vice President, Human Resources at Rice Energy Inc. from April 2017 to November 2017. Additionally, Ms. Evancho served as Global Director, Talent Management at MSA Safety, Inc. (manufacturer of industrial safety equipment) from November 2011 to April 2017.
Todd M. James (38)	Chief Accounting Officer (2019)	Mr. James was appointed as the Chief Accounting Officer of EQT Corporation in November 2019. Prior to joining EQT Corporation, Mr. James served as the Corporate Controller and Chief Accounting Officer of L.B. Foster Company (manufacturer and distributor of products and services for transportation and energy infrastructure) from April 2018 to October 2019. Prior to that he served as the Senior Director, Technical Accounting and Financial Reporting at Rice Energy Inc. from December 2014 through its acquisition by EQT Corporation in November 2017 and until February 2018. Prior to joining Rice Energy, Mr. James was a Senior Manager, Assurance at PricewaterhouseCoopers LLP (public accounting firm), where he worked from August 2005 to November 2014.
William E. Jordan (40)	Executive Vice President, General Counsel and Corporate Secretary (2019)	Mr. Jordan was appointed as the Executive Vice President and General Counsel of EQT Corporation in July 2019 and assumed the role of Corporate Secretary in November 2020. Mr. Jordan served as an advisor to the Rice Investment Group (multi-strategy investment fund investing in all verticals of the oil and gas sectors) from May 2018 until July 2019. Prior to that, he served as the Senior Vice President, General Counsel and Corporate Secretary of Rice Energy Inc. and Senior Vice President, General Counsel and Corporate Secretary of Rice Midstream Partners LP (former midstream services affiliate of Rice Energy Inc.), in each case from January 2014 until their acquisition by EQT Corporation in November 2017. From September 2005 to December 2013, Mr. Jordan was an associate at Vinson & Elkins LLP (an international law firm) representing public and private companies in capital markets offerings and mergers and acquisitions, primarily in the oil and natural gas industry.
David M. Khani (57)	Chief Financial Officer (2020)	Mr. Khani was appointed as the Chief Financial Officer of EQT Corporation in January 2020. Prior to joining EQT Corporation, Mr. Khani served as the Executive Vice President and Chief Financial Officer of CONSOL Energy (energy company primarily focused on developing coal interests), from March 2013 to December 2019; and as Vice President, Finance at CONSOL Energy from September 2011 to March 2013. In addition, Mr. Khani served as Chief Financial Officer and as a member of the Board of Directors of CONE Midstream LLC (midstream services affiliate of CONSOL Energy) from September 2014 to January 2018; as a member of the Board of Directors of CNX Coal Resources (coal mining affiliate of CONSOL Energy) from July 2015 to August 2017; and as Chief Financial Officer and as a member of the Board of Directors of CONSOL Coal Resources (coal mining affiliate of CONSOL Energy) from August 2017 to December 2019.
Toby Z. Rice (39)	President and Chief Executive Officer (2019)	Mr. Rice was appointed as President and Chief Executive Officer of EQT Corporation in July 2019, when he also was elected to EQT Corporation's Board of Directors. Mr. Rice has served as a Partner at the Rice Investment Group, a multi-strategy fund investing in all verticals of the oil and gas sector, since May 2018. From October 2014 until its acquisition by EQT Corporation in November 2017, Mr. Rice was President and Chief Operating Officer of Rice Energy Inc. and served on the Board of Directors of Rice Energy Inc. from October 2013 to November 2017. Prior to that, he served in a number of positions with Rice Energy, its affiliates and predecessor entities beginning in February 2007, including as President and Chief Executive Officer of a predecessor entity from February 2008 through September 2013. Mr. Rice is the brother of Daniel J. Rice IV, a member of EQT Corporation's Board of Directors since November 2017.

All executive officers have either elected to participate in the EQT Corporation Executive Severance Plan (which includes confidentiality and non-compete provisions) or executed non-compete agreements with EQT Corporation, and each of the executive officers serve at the pleasure of our 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.

## PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol "EQT."

As of February 12, 2021, there were 1,985 shareholders of record of our common stock.

On March 26, 2020, we announced the suspension of our quarterly cash dividend on our common stock for purposes of accelerating cash flow to be used for our Deleveraging Plan. The amount and timing of dividends declared and paid by us, if any, are subject to the discretion of our Board of Directors and depends on business conditions, such as our results of operations and financial condition, strategic direction and other factors. Our Board of Directors have the discretion to change the annual dividend rate at any time for any reason.

#### Recent Sales of Unregistered Securities

None.

#### Market Repurchases

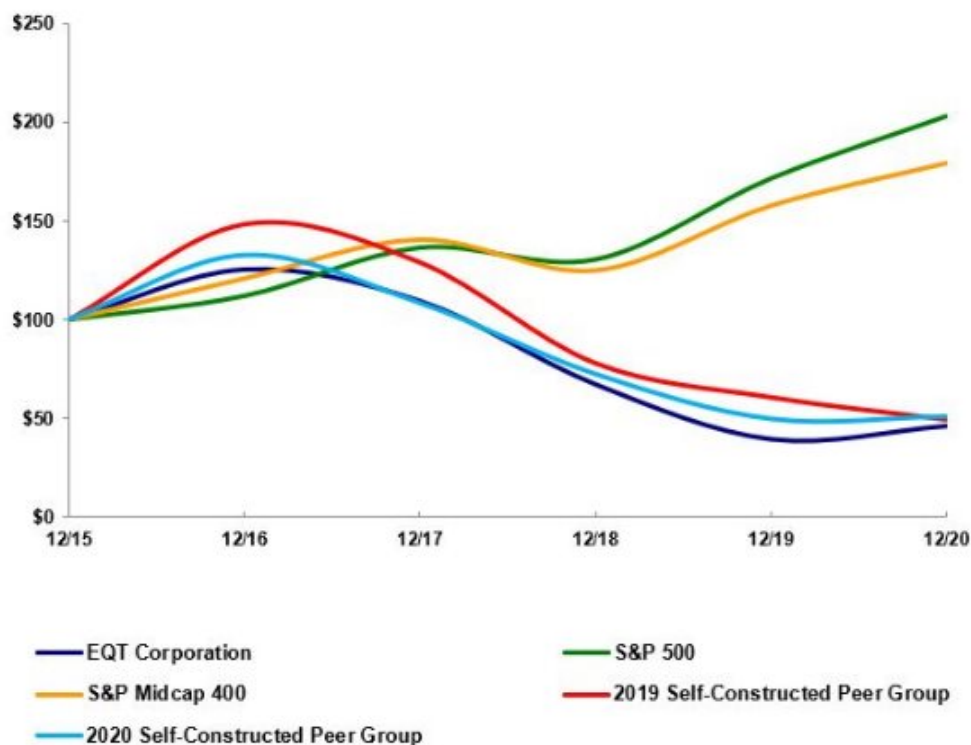
We did not repurchase any equity securities registered under Section 12 of the Securities Exchange Act of 1934, as amended, during the three months ended December 31, 2020.

#### Stock Performance Graph

The following graph compares the most recent cumulative five-year total return provided to shareholders of our common stock relative to the cumulative five-year total returns of the Standard & Poor's (S&P) 500 Index, the S&P MidCap 400 Index and two customized peer groups, the 2019 Self-Constructed Peer Group and 2020 Self-Constructed Peer Group, whose company composition is discussed in footnotes (a) and (b), respectively, below. Our common stock was included in the S&P 500 Index until the Separation and Distribution in 2018, following which our common stock was added to the S&P MidCap 400 Index. We have presented both indices for comparison in the following graph. An investment of \$100, with reinvestment of all dividends, is assumed to have been made in our common stock, in the S&P 500 Index, the S&P MidCap 400 Index and in each of the peer groups on December 31, 2015 and its relative performance is tracked through December 31, 2020. Historical prices prior to the Separation and Distribution have been adjusted to reflect the value of the Separation and Distribution. The stock price performance shown in the graph below is not necessarily indicative of future stock price performance.

### COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN\*

Among EQT Corporation, the S&P 500 Index, the S&P Midcap 400 Index, 2019 Self-Constructed Peer Group and 2020 Self-Constructed Peer Group



\*\$100 invested on 12/31/15 in stock, index, or peer group, including reinvestment of dividends.  
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	12/15	12/16	12/17	12/18	12/19	12/20
EQT Corporation	\$ 100.00	\$ 125.69	\$ 109.60	\$ 67.06	\$ 39.01	\$ 45.74
S&P 500	100.00	111.96	136.40	130.42	171.49	203.04
S&P MidCap 400 Index	100.00	120.74	140.35	124.80	157.49	179.00
2019 Self-Constructed Peer Group (a)	100.00	148.63	129.24	77.93	60.57	49.24
2020 Self-Constructed Peer Group (b)	100.00	132.65	108.37	72.36	49.65	50.87

- (a) The 2019 Self-Constructed Peer Group includes the following twelve companies: Antero Resources Corp., Cabot Oil & Gas Corp., Chesapeake Energy Corp., Cimarex Energy Co., CNX Resources Corp., Gulfport Energy Corp., Murphy Oil Corp., Ovintiv Inc. (formerly Encana Corp.), QEP Resources, Inc., Range Resources Corp., SM Energy Co. and Southwestern Energy Co. WPX Energy Inc. was included in the self-constructed peer group that served as the basis for the stock performance graph in our Annual Report on Form 10-K for the year ended December 31, 2019, but it has been excluded from the 2019 Self-Constructed Peer Group because it was acquired during 2020.
- (b) The 2020 Self-Constructed Peer Group includes the following eight companies: Antero Resources Corp., Cabot Oil & Gas Corp., Chesapeake Energy Corp., CNX Resources Corp., Comstock Resources, Inc., Gulfport Energy Corp., Range Resources Corp. and Southwestern Energy Co. The 2020 Self-Constructed Peer Group is comprised of the companies included in our 2020 performance peer group, as set forth in our definitive proxy statement relating to our 2020 annual meeting of shareholders, and were selected by the Management Development and Compensation Committee of the Board of Directors for purposes of evaluating our relative total shareholder return under the 2020 Incentive Performance Share Unit Program.

**Item 6. Selected Financial Data**

Not Applicable.

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

*The following discussion and analysis of financial condition and results of operations should be read in conjunction with the Consolidated Financial Statements and the notes thereto included in Item 8., "Financial Statements and Supplementary Data."*

**Consolidated Results of Operations**

Net loss for 2020 was \$967 million, \$3.71 per diluted share, an improvement of \$255 million compared to net loss for 2019 of \$1,222 million, \$4.79 per diluted share. The variance was attributable primarily to decreased impairments, the gain on the Equitrans Share Exchange (defined and discussed in Note 5 to the Consolidated Financial Statements), decreased other operating expenses, decreased depreciation and depletion expense and decreased transportation and processing expense, partly offset by decreased operating revenues, increased interest expense and decreased dividend and other income.

See Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on [Form 10-K](#) for the year ended December 31, 2019, which is incorporated herein by reference, for discussion and analysis of consolidated results of operations for the year ended December 31, 2018.

See "Sales Volumes and Revenues" and "Operating Expenses" for discussions of items affecting operating income and "Other Income Statement Items" for a discussion of other income statement items. See "Investing Activities" under "Capital Resources and Liquidity" for a discussion of capital expenditures.

**Average Realized Price Reconciliation**

The following table presents detailed natural gas and liquids operational information to assist in the understanding of our consolidated operations, including the calculation of our average realized price (\$/Mcf), which is based on adjusted operating revenues, a non-GAAP supplemental financial measure. Adjusted operating revenues is presented because it is an important measure we use to evaluate period-to-period comparisons of earnings trends. Adjusted operating revenues should not be considered as an alternative to total operating revenues. See "Non-GAAP Financial Measures Reconciliation" for a reconciliation of adjusted operating revenues with total operating revenues, the most directly comparable financial measure calculated in accordance with GAAP.

	Years Ended December 31,	
	2020	2019
	(Thousands, unless otherwise noted)	
NATURAL GAS		
Sales volume (MMcf)	1,418,774	1,435,134
NYMEX price (\$/MMBtu) (a)	\$ 2.09	\$ 2.63
Btu uplift	0.11	0.13
Natural gas price (\$/Mcf)	\$ 2.20	\$ 2.76
Basis (\$/Mcf) (b)	\$ (0.47)	\$ (0.28)
Cash settled basis swaps (not designated as hedges) (\$/Mcf)	0.05	(0.04)
Average differential, including cash settled basis swaps (\$/Mcf)	\$ (0.42)	\$ (0.32)
Average adjusted price (\$/Mcf)	\$ 1.78	\$ 2.44
Cash settled derivatives (not designated as hedges) (\$/Mcf)	0.59	0.21
Average natural gas price, including cash settled derivatives (\$/Mcf)	\$ 2.37	\$ 2.65
Natural gas sales, including cash settled derivatives	\$ 3,359,583	\$ 3,805,977
LIQUIDS		
Natural gas liquids (NGLs), excluding ethane:		
Sales volume (MMcfe) (c)	44,702	44,082
Sales volume (Mbbbl)	7,451	7,348
Price (\$/Bbl)	\$ 20.51	\$ 23.63
Cash settled derivatives (not designated as hedges) (\$/Bbl)	(0.12)	2.19
Average NGLs price, including cash settled derivatives (\$/Bbl)	\$ 20.39	\$ 25.82
NGLs sales	\$ 151,877	\$ 189,718
Ethane:		
Sales volume (MMcfe) (c)	29,489	23,748
Sales volume (Mbbbl)	4,914	3,957
Price (\$/Bbl)	\$ 3.48	\$ 6.16
Cash settled derivatives (not designated as hedges) (\$/Bbl)	—	1.02
Average Ethane price, including cash settled derivatives (\$/Bbl)	\$ 3.48	\$ 7.18
Ethane sales	\$ 17,085	\$ 28,414
Oil:		
Sales volume (MMcfe) (c)	4,827	4,932
Sales volume (Mbbbl)	804	822
Price (\$/Bbl)	\$ 25.57	\$ 40.90
Oil sales	\$ 20,574	\$ 33,620
Total liquids sales volume (MMcfe) (c)	79,018	72,762
Total liquids sales volume (Mbbbl)	13,169	12,127
Total liquids sales	\$ 189,536	\$ 251,752
TOTAL		
Total natural gas and liquids sales, including cash settled derivatives (d)	\$ 3,549,119	\$ 4,057,729
Total sales volume (MMcfe)	1,497,792	1,507,896
Average realized price (\$/Mcf)	\$ 2.37	\$ 2.69

- (a) Our volume weighted NYMEX natural gas price (actual average NYMEX natural gas price (\$/MMBtu)) was \$2.08 and \$2.63 for the years ended December 31, 2020 and 2019, respectively.
- (b) Basis represents the difference between the ultimate sales price for natural gas and the NYMEX natural gas price.
- (c) NGLs, ethane and oil were converted to Mcfe at a rate of six Mcfe per barrel.
- (d) Total natural gas and liquids sales, including cash settled derivatives, is also referred to in this report as adjusted operating revenues, a non-GAAP supplemental financial measure.

## Non-GAAP Financial Measures Reconciliation

The table below reconciles adjusted operating revenues, a non-GAAP supplemental financial measure, with total operating revenues, its most directly comparable financial measure calculated in accordance with GAAP. Adjusted operating revenues (also referred to in this report as total natural gas and liquids sales, including cash settled derivatives) is presented because it is an important measure we use to evaluate period-to-period comparisons of earnings trends. Adjusted operating revenues excludes the revenue impacts of changes in the fair value of derivative instruments prior to settlement and net marketing services and other. We use adjusted operating revenues to evaluate earnings trends because, as a result of the measure's exclusion of the often-volatile changes in the fair value of derivative instruments prior to settlement, the measure reflects only the impact of settled derivative contracts. Net marketing services and other primarily includes the costs of, and recoveries on, pipeline capacity releases. Because we consider net marketing services and other to be unrelated to our natural gas and liquids production activities, adjusted operating revenues excludes net marketing services and other. We believe that adjusted operating revenues provides useful information to investors for evaluating period-to-period comparisons of earnings trends.

	Years Ended December 31,	
	2020	2019
	(Thousands, unless otherwise noted)	
Total operating revenues	\$ 3,058,843	\$ 4,416,484
Add (deduct):		
Gain on derivatives not designated as hedges	(400,214)	(616,634)
Net cash settlements received on derivatives not designated as hedges	897,190	246,639
Premiums received for derivatives that settled during the period	1,630	19,676
Net marketing services and other	(8,330)	(8,436)
Adjusted operating revenues, a non-GAAP financial measure	\$ 3,549,119	\$ 4,057,729
Total sales volumes (MMcfe)	1,497,792	1,507,896
Average realized price (\$/Mcf)	\$ 2.37	\$ 2.69

## Sales Volumes and Revenues

	Years Ended December 31,		
	2020	2019	%
	(Thousands, unless otherwise noted)		
Sales volume by shale (MMcfe):			
Marcellus (a)	1,314,801	1,270,352	3.5
Ohio Utica	177,864	231,545	(23.2)
Other	5,127	5,999	(14.5)
Total sales volumes (b)	1,497,792	1,507,896	(0.7)
Average daily sales volumes (MMcfe/d)	4,092	4,131	(0.9)
Operating revenues:			
Sales of natural gas, NGLs and oil	\$ 2,650,299	\$ 3,791,414	(30.1)
Gain on derivatives not designated as hedges	400,214	616,634	(35.1)
Net marketing services and other	8,330	8,436	(1.3)
Total operating revenues	\$ 3,058,843	\$ 4,416,484	(30.7)

(a) Includes Upper Devonian wells.

(b) NGLs, ethane and oil were converted to Mcfe at a rate of six Mcfe per barrel.

*Sales of natural gas, NGLs and oil.* Sales of natural gas, NGLs and oil decreased for 2020 compared to 2019 due to a lower average realized price and lower sales volumes. Average realized price decreased due to lower NYMEX and unfavorable differential, partly offset by higher cash settled derivatives. For 2020 and 2019, we received \$898.8 million and \$266.3 million, respectively, of net cash settlements, including net premiums received, on derivatives not designated as hedges, which are included in average realized price but may not be included in operating revenues. Sales volumes for 2020 decreased compared

to 2019 due primarily to our strategic decisions to temporarily curtail production beginning in May 2020 and ending in November 2020 (the Strategic Production Curtailments) which resulted in a decrease to sales volumes of approximately 46 Bcfe. Sales volumes for 2020 also decreased compared to 2019 by 16 Bcfe as a result of the 2020 Divestitures (defined in Note 7 to the Consolidated Financial Statements). These decreases were partly offset by operational efficiencies realized throughout the year from increased production up-time and positively impacted sales volumes as well as an increase of approximately 12 Bcfe due to the Chevron Acquisition.

*Gain on derivatives not designated as hedges.* For 2020, we recognized a gain on derivatives not designated as hedges of \$400.2 million compared to \$616.6 million for 2019. The gains for 2020 and 2019 were related primarily to decreases in the fair market value of our NYMEX swaps and options due to increases in NYMEX forward prices.

## Operating Expenses

The following table presents information on our production-related operating expenses.

	Years Ended December 31,		
	2020	2019	%
(Thousands, unless otherwise noted)			
<b>Operating expenses:</b>			
Gathering	\$ 1,068,590	\$ 1,038,646	2.9
Transmission	506,668	588,302	(13.9)
Processing	135,476	125,804	7.7
Lease operating expenses (LOE), excluding production taxes	109,027	84,501	29.0
Production taxes	46,376	69,284	(33.1)
Exploration	5,484	7,223	(24.1)
Selling, general and administrative	174,769	170,611	2.4
Production depletion	\$ 1,375,542	\$ 1,524,112	(9.7)
Other depreciation and depletion	17,923	14,633	22.5
Total depreciation and depletion	\$ 1,393,465	\$ 1,538,745	(9.4)
<b>Per Unit (\$/Mcf):</b>			
Gathering	\$ 0.71	\$ 0.69	2.9
Transmission	0.34	0.39	(12.8)
Processing	0.09	0.08	12.5
LOE, excluding production taxes	0.07	0.06	16.7
Production taxes	0.03	0.05	(40.0)
Exploration	—	—	—
Selling, general and administrative	0.12	0.11	9.1
Production depletion	0.92	1.01	(8.9)

*Gathering.* Gathering expense increased on an absolute and per Mcfe basis for 2020 compared to 2019 due to a higher gathering rate structure as a result of the Consolidated GGA (defined in Note 5 to the Consolidated Financial Statements), partly offset by lower gathered volumes as a result of the Strategic Production Curtailments. We expect to realize fee relief and a lower gathering rate structure from the Consolidated GGA beginning on the Mountain Valley Pipeline in-service date.

*Transmission.* Transmission expense decreased on an absolute and per Mcfe basis for 2020 compared to 2019 due primarily to released capacity on, and credits received from, the Texas Eastern Transmission Pipeline, partly offset by higher costs associated with additional capacity on the Tennessee Gas Pipeline.

*LOE.* LOE increased on an absolute and per Mcfe basis for 2020 compared to 2019 due primarily to higher repairs and maintenance costs as a result of our increased focus on optimizing production from currently producing wells as well as higher salt water disposal costs.

*Production taxes.* Production taxes decreased on an absolute and per Mcfe basis for 2020 compared to 2019 due primarily to lower severance taxes and Pennsylvania impact fees as a result of lower commodity prices.

*Depreciation and depletion.* Production depletion decreased on an absolute and per Mcfe basis for 2020 compared to 2019 due primarily to a lower annual depletion rate and lower volumes.

*Amortization of intangible assets.* Amortization of intangible assets for 2020 was \$26.0 million compared to \$35.9 million for 2019. The decrease was due primarily to the impairment of intangible assets recognized in the third quarter of 2019 as described below, which decreased the amortization rate. The intangible assets were fully amortized in November 2020.

*Impairment/loss on sale/exchange of long-lived assets.* During 2020, we recognized a loss on sale/exchange of long-lived assets of \$100.7 million, of which \$61.6 million related to the 2020 Asset Exchange Transactions (defined and discussed in Note 6 to the Consolidated Financial Statements) and \$39.1 million related to asset sales (described in Note 7 to the Consolidated Financial Statements). During the fourth quarter of 2019, we recorded impairment of long-lived assets of \$1,124.4 million, of which \$1,035.7 million was associated with our non-strategic assets located in the Ohio Utica and \$88.7 million was associated with our Pennsylvania and West Virginia Utica assets. The impairment was due primarily to depressed natural gas prices and changes in our development strategy. During the third quarter of 2019, we recorded a loss on exchange of long-lived assets of \$13.9 million related to the 2019 Asset Exchange Transaction (defined and discussed in Note 6 to the Consolidated Financial Statements). See Note 1 to the Consolidated Financial Statements for a discussion of the 2019 impairment test.

*Impairment of intangible and other assets.* During the fourth quarter of 2020, we recognized impairment of \$34.7 million, of which \$22.8 million related to our assessment that the fair values of certain of our right-of-use lease assets were less than their carrying values and \$11.9 million related to impairments of certain non-operating receivables as a result of expected credit losses. During the third quarter of 2019, we recognized impairment of \$15.4 million of intangible assets associated with non-compete agreements for former Rice Energy Inc. executives who are now our employees.

*Impairment and expiration of leases.* Impairment and expiration of leases for 2020 was \$306.7 million compared to \$556.4 million for 2019. The decrease was driven by increased lease expirations in 2019 due to our change in strategic focus to core development opportunities as well as changes in market conditions.

*Other operating expenses.* Other operating expenses of \$28.5 million in 2020 were related primarily to transactions, changes in legal reserves, including settlements and reorganization. Other operating expenses of \$199.4 million in 2019 were related primarily to reorganization, due to reductions in workforce, which resulted in the recognition of severance and other termination benefits, changes in legal reserves, including settlements, contract terminations and the proxy contest. See Note 1 to the Consolidated Financial Statements.

#### **Other Income Statement Items**

*Gain on Equitrans Share Exchange.* During the first quarter of 2020, we recognized a gain on the Equitrans Share Exchange as described in Note 5 to the Consolidated Financial Statements.

*Loss on investment in Equitrans Midstream Corporation.* Our investment in Equitrans Midstream is recorded at fair value by multiplying the closing stock price of Equitrans Midstream's common stock by the number of shares of Equitrans Midstream's common stock that we own. Changes in fair value are recorded in loss on investment in Equitrans Midstream Corporation in the Statements of Consolidated Operations. Our investment in Equitrans Midstream fluctuates with changes in Equitrans Midstream's stock price, which was \$8.04 and \$13.36 as of December 31, 2020 and 2019, respectively. Note, the effect of the sale of 50% of our shares of Equitrans Midstream's common stock was recorded as a reduction to the investment in Equitrans Midstream in conjunction with our recognition of the gain on the Equitrans Share Exchange. See Note 5 to the Consolidated Financial Statements.

*Dividend and other income.* The decrease in 2020 as compared to 2019 is due primarily to lower dividends received from our investment in Equitrans Midstream driven by the decrease in the number of shares of Equitrans Midstream's common stock that we own.

*Loss on debt extinguishment.* During 2020, we recognized a loss on debt extinguishment related to the repayment of all or a portion of our 4.875% senior notes, 2.50% senior notes, 3.00% senior notes, floating rate notes and Term Loan Facility (defined and discussed in Note 10 to the Consolidated Financial Statements). See Note 10 to the Consolidated Financial Statements.

*Interest expense.* Interest expense increased for 2020 compared to 2019 due to increased interest incurred on new debt issued in 2020 as well as interest incurred on letters of credit issued in 2020. These increases were partly offset by lower interest incurred due to the repayment of all or a portion of our 8.125% senior notes, 4.875% senior notes, floating rate notes and 2.50% senior notes and decreased borrowings on our credit facility. See Note 10 to the Consolidated Financial Statements.

The adjusted interest rate under the Adjustable Rate Notes (defined and discussed in Note 10 to the Consolidated Financial Statements) cannot exceed 2% of the original interest rate first set forth on the face of the Adjustable Rate Notes; however, if our credit ratings improve, the interest rate under the Adjustable Rate Notes could be reduced to as low as the original interest rate set forth on the face of the Adjustable Rate Notes.

*Income tax benefit.* See Note 9 to the Consolidated Financial Statements.

### **Impairment of Oil and Gas Properties**

See "Critical Accounting Policies and Estimates" and Note 1 to the Consolidated Financial Statements for a discussion of our accounting policies and significant assumptions related to impairment of our oil and gas properties. See also Item 1A., "Risk Factors – Natural gas, NGLs and oil price declines, and changes in our development strategy, have resulted in impairment of certain of our assets. Future declines in commodity prices, increases in operating costs or adverse changes in well performance or additional changes in our development strategy 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**

Although we cannot provide any assurance, we believe cash flows from operating activities and availability under our credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures and commitments for at least the next twelve months and, based on current expectations, for the long-term.

#### ***Credit Facility***

We primarily use borrowings under our credit facility to fund working capital needs, timing differences between capital expenditures and other cash uses and cash flows from operating activities, margin deposit requirements on our derivative instruments and credit assurance requirements, including collateral, in support of our midstream service contracts, joint venture arrangements or construction contracts. See Note 10 to the Consolidated Financial Statements for further discussion of our credit facility.

#### ***Known Contractual and Other Obligations; Planned Capital Expenditures***

*Purchase obligations.* We have 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. We have entered into agreements to release some of our capacity under these long-term contracts. We also have commitments for processing capacity in order to extract heavier liquid hydrocarbons from the natural gas stream. Aggregate future payments for these items as of December 31, 2020 were \$24.8 billion, composed of \$1.3 billion in 2021, \$1.7 billion in 2022, \$1.8 billion in 2023, \$1.9 billion in 2024, \$1.8 billion in 2025 and \$16.3 billion primarily in 2026 through 2042. We also have commitments to purchase equipment, materials, frac sand for use as a proppant in our hydraulic fracturing operations and minimum volume commitments associated with certain water agreements. As of December 31, 2020, future commitments under these contracts were \$96.5 million in 2021 and \$14.3 million in 2022.

*Contractual Commitments.* We have contractual commitments under our debt agreements including interest payments and principal repayments. See Note 10 to the Consolidated Financial Statements for further discussion including the timing of principal repayments.

*Unrecognized Tax Benefits.* As discussed in Note 9 to the Consolidated Financial Statements, we had a total reserve for unrecognized tax benefits at December 31, 2020 of \$181.2 million, of which \$90.3 million is offset against deferred tax assets for general business tax credit carryforwards and NOLs. We are currently unable to make reasonably reliable estimates of the period of cash settlement of these potential liabilities with taxing authorities.

**Planned Capital Expenditures.** In 2021, we expect to spend approximately \$1.1 to \$1.2 billion in total capital expenditures, excluding amounts attributable to noncontrolling interests. Because we are the operator of a high percentage of our acreage, the amount and timing of these capital expenditures are largely discretionary. We could choose to defer a portion of these planned 2021 capital expenditures depending on a variety of factors, including prevailing and anticipated prices for natural gas, NGLs and oil; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; and drilling, completion and acquisition costs.

### **Operating Activities**

Net cash provided by operating activities was \$1,538 million for 2020 compared to \$1,852 million for 2019. The decrease was due primarily to lower cash operating revenues and unfavorable timing of working capital payments, partly offset by increased cash settlements received on derivatives not designated as hedges, income tax refunds, plus interest, received of \$440 million during 2020 and lower cash operating expenses.

Our cash flows from operating activities are affected by movements in the market price for commodities. We are unable to predict such 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 on our revenue, profitability, future rate of growth, liquidity and financial position." for further information.

### **Investing Activities**

Net cash used in investing activities was \$1,556 million for 2020 compared to \$1,601 million for 2019. The decrease was due to lower capital expenditures as a result of our change in strategic focus from production growth to capital efficiency as well as cash received from asset sales and the Equitrans Share Exchange. The decrease was partly offset by cash paid for acquisitions as described in Note 6.

The following table summarizes our capital expenditures.

	Years Ended December 31,	
	2020	2019
	(Millions)	
Reserve development	\$ 839	\$ 1,377
Land and lease (a)	121	195
Capitalized overhead	51	77
Capitalized interest	17	24
Other production infrastructure	40	97
Other corporate items	11	3
Total capital expenditures	1,079	1,773
(Deduct) add non-cash items (b)	(37)	(171)
Total cash capital expenditures	\$ 1,042	\$ 1,602

(a) Capital expenditures attributable to noncontrolling interests were \$4.9 million for the year ended December 31, 2020.

(b) Represents the net impact of non-cash capital expenditures, including capitalized share-based compensation costs, the effect of timing of receivables from working interest partners and accrued capital expenditures. The impact of accrued capital expenditures includes the reversal of the prior period accrual as well as the current period estimate.

### **Financing Activities**

Net cash provided by financing activities was \$32 million for 2020 compared to net cash used in financing activities of \$249 million for 2019. For 2020, the primary source of financing cash flows was net proceeds from the issuance of debt and equity and the primary use of financing cash flows was net repayments of debt. For 2019, the primary uses of financing cash flows were net repayments of debt and credit facility borrowings, and the primary source of financing cash flows was net proceeds from borrowings on the Term Loan Facility. See Note 10 to the Consolidated Financial Statements for further discussion of our debt.

On March 26, 2020, we announced the suspension of our quarterly cash dividend on our common stock for purposes of accelerating cash flow to be used for our Deleveraging Plan.

Depending on our actual and anticipated sources and uses of liquidity, prevailing market conditions and other factors, we may from time to time seek to retire or repurchase our outstanding debt or equity securities through cash purchases in the open market or privately negotiated transactions. The amounts involved in any such transactions may be material. Additionally, we plan to dispose of our remaining retained shares of Equitrans Midstream's common stock and use the proceeds to reduce our debt.

See Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on [Form 10-K](#) for the year ended December 31, 2019, which is incorporated herein by reference, for discussion and analysis of operating, investing and financing activities for the year ended December 31, 2018.

### ***Security Ratings and Financing Triggers***

The table below reflects the credit ratings and rating outlooks assigned to our debt instruments at February 12, 2021. Our credit ratings and rating outlooks are subject to revision or withdrawal at any time by the assigning rating agency, and each rating should be evaluated independent from any other rating. We 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 rating agency if, in the rating agency's judgment, circumstances so warrant. See Note 3 to the Consolidated Financial Statements for further discussion of what is deemed investment grade.

<b>Rating agency</b>	<b>Senior notes</b>	<b>Outlook</b>
Moody's Investors Service (Moody's)	Ba2	Stable
Standard & Poor's Ratings Service (S&P)	BB	Stable
Fitch Ratings Service (Fitch)	BB	Positive

Changes in credit ratings may affect our access to the capital markets, the cost of short-term debt through interest rates and fees under our lines of credit, the interest rate on the Adjustable Rate Notes, the rates available on new long-term debt, our pool of investors and funding sources, the borrowing costs and margin deposit requirements on our OTC derivative instruments and credit assurance requirements, including collateral, in support of our midstream service contracts, joint venture arrangements or construction contracts. Margin deposits on our OTC derivative instruments are also subject to factors other than credit rating, such as natural gas prices and credit thresholds set forth in the agreements between us and hedging counterparties. As of February 12, 2021, we had sufficient unused borrowing capacity, net of letters of credit, under our credit facility to satisfy any requests for margin deposit or other collateral that our counterparties are permitted to request of us pursuant to our OTC derivative instruments, midstream services contracts and other contracts. As of February 12, 2021, such assurances could be up to approximately \$1.0 billion, inclusive of letters of credit, OTC derivative instrument margin deposits and other collateral posted of approximately \$0.9 billion in the aggregate. See Notes 3 and 10 to the Consolidated Financial Statements for further information.

Our debt agreements and other financial obligations contain various provisions that, if not complied with, could result in default or event of default under our credit facility, mandatory partial or full repayment of amounts outstanding, reduced loan capacity or other 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. Our credit facility contains financial covenants that require us to have a total debt-to-total capitalization ratio no greater than 65%. The calculation of this ratio excludes the effects of accumulated other comprehensive income. As of December 31, 2020, we were in compliance with all debt provisions and covenants.

See Note 10 to the Consolidated Financial Statements for a discussion of the borrowings under our credit facility.

### ***Commodity Risk Management***

The substantial majority of our commodity risk management program is related to hedging sales of our produced natural gas. The overall objective of our hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices. The derivative commodity instruments that we use are primarily swap, collar and option agreements. The

following table summarizes the approximate volumes and prices of our NYMEX hedge positions through 2024 as of February 12, 2021.

	2021 (a)	2022	2023	2024
<b>Swaps:</b>				
Volume (MMDth)	1,082	455	69	2
Average Price (\$/Dth)	\$ 2.71	\$ 2.66	\$ 2.48	\$ 2.67
<b>Calls – Net Short:</b>				
Volume (MMDth)	407	284	77	15
Average Short Strike Price (\$/Dth)	\$ 2.91	\$ 2.89	\$ 2.89	\$ 3.11
<b>Puts – Net Long:</b>				
Volume (MMDth)	227	135	69	15
Average Long Strike Price (\$/Dth)	\$ 2.59	\$ 2.35	\$ 2.40	\$ 2.45
<b>Fixed Price Sales (b):</b>				
Volume (MMDth)	72	4	3	—
Average Price (\$/Dth)	\$ 2.50	\$ 2.38	\$ 2.38	—

(a) Full year 2021.

(b) The difference between the fixed price and NYMEX price is included in average differential presented in our price reconciliation in the "Average Realized Price Reconciliation." The fixed price natural gas sales agreements can be physically or financially settled.

For 2021, 2022, 2023 and 2024, we have natural gas sales agreements for approximately 18 MMDth, 18 MMDth, 88 MMDth and 11 MMDth, respectively, that include average NYMEX ceiling prices of \$3.17, \$3.17, \$2.84 and \$3.21, respectively. We have also entered into derivative instruments to hedge basis. We may use other contractual agreements to implement our commodity hedging strategy from time to time.

During 2020, we purchased \$47 million of net options with the primary purpose of reducing future NYMEX based payments that could be due in 2021, 2022 and 2023 to Equitrans Midstream related to the Henry Hub Cash Bonus (defined and discussed in Note 5 to the Consolidated Financial Statements) provided for by the Consolidated GGA.

See Item 7A., "Quantitative and Qualitative Disclosures About Market Risk" and Note 3 to the Consolidated Financial Statements for further discussion of our hedging program.

#### Off-Balance Sheet Arrangements

See Note 17 to the Consolidated Financial Statements for a discussion of our guarantees.

#### Commitments and Contingencies

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against us. While the amounts claimed may be substantial, we are unable to predict with certainty the ultimate outcome of such claims and proceedings. We accrue legal and other direct costs related to loss contingencies when actually incurred. We have established reserves that we believe to be appropriate for pending matters and, after consultation with counsel and giving appropriate consideration to available insurance, we believe that the ultimate outcome of any matter currently pending against us will not materially affect our financial condition, results of operations or liquidity. See Note 16 to the Consolidated Financial Statements for a discussion of our commitments and contingencies. See Item 3., "Legal Proceedings."

#### Recently Issued Accounting Standards

Our recently issued accounting standards are described in Note 1 to the Consolidated Financial Statements.

#### Critical Accounting Policies and Estimates

Our significant accounting policies are described in Note 1 to the Consolidated Financial Statements. Management's discussion and analysis of the Consolidated Financial Statements and results of operations are based on our 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 Audit Committee of our Board of Directors (the Audit Committee), relate to our more significant judgments and estimates used in the preparation of our Consolidated Financial Statements. Actual results could differ from our estimates.

*Accounting for Gas, NGL and Oil Producing Activities.* We use the successful efforts method of accounting for our oil and gas producing activities.

The carrying values of our proved oil and gas properties are reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. To determine whether impairment of our oil and gas properties has occurred, we compare the estimated expected undiscounted future cash flows to the carrying values of those properties. Estimated future cash flows are based on proved and, if determined reasonable by management, risk-adjusted probable reserves and assumptions generally consistent with the assumptions used by us 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 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 rates and other assumptions that marketplace participants would use in their fair value estimates.

Capitalized costs of unproved oil and gas properties are evaluated for recoverability on a prospective basis at least annually. Indicators of potential impairment include changes due to economic factors, potential shifts in business strategy 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. If we do not intend to drill on the property prior to expiration of the lease or do not have the intent and ability to extend, renew, trade or sell the lease prior to expiration, impairment expense is recorded.

We believe accounting for gas, NGL and oil producing activities is a "critical accounting estimate" because the evaluations of impairment of proved properties involve significant judgment about future events, such as future sales prices of natural gas and NGLs and future production costs, as well as the amount of natural gas and NGLs recorded and timing of recoveries. Significant changes in these estimates could result in the costs of our proved and unproved properties not being recoverable; therefore, we would be required to recognize impairment. See "Impairment of Oil and Gas Properties" and Note 1 to the Consolidated Financial Statements for additional information on our 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 that, 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.

Our estimates of proved reserves are reassessed annually using geological, reservoir and production performance data. Reserve estimates are prepared by our engineers and audited by 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 certain 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 our Consolidated Financial Statements.

We estimate future net cash flows from natural gas, NGLs and crude oil reserves based on selling prices and costs using a twelve-month average price, which is calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the twelve-month period and, as such, 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 based on future statutory tax rates and tax deductions and credits available under current laws.

We believe oil and gas reserves is a "critical accounting estimate" because we must periodically reevaluate proved reserves along with estimates of future production rates, production costs and the timing of development expenditures. Future results of operations and the strength of our Consolidated Balance Sheet for any quarterly or annual period could be materially affected by changes in our assumptions. Significant changes in these estimates could result in a change to our estimated reserves, which could lead to a material change to our production depletion expense. See "Impairment of Oil and Gas Properties" for additional information on our oil and gas reserves.

*Income Taxes.* We recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been included in our Consolidated Financial Statements or tax returns.

We have recorded deferred tax assets resulting from federal and state NOL carryforwards, an AMT credit carryforward, other federal tax credit carryforwards, unrealized capacity contract losses, incentive compensation and investments in securities. We have established a valuation allowance against a portion of the deferred tax assets related primarily to federal and state NOL carryforwards and our investment in Equitrans Midstream because we believe it is more likely than not that those deferred tax assets will not be fully realized. We established a valuation allowance against the state and part of the federal deferred tax asset related to our investment in Equitrans Midstream because the fair value loss is not expected to be fully realized for tax purposes due to capital loss limitations. No other significant valuation allowances have been established as we believe that future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize the deferred tax assets. Changes to our valuation allowance would impact our income tax expense and net income in the period in which such a determination is made.

We estimate the amount of financial statement benefit recorded for uncertain tax positions. See Note 9 to our Consolidated Financial Statements.

We believe income taxes are "critical accounting estimates" because we must assess the likelihood that our deferred tax assets will be recovered from future taxable income and exercise judgment on the amount of financial statement benefit recorded for uncertain tax positions. When evaluating whether or not a valuation allowance should be established, we exercise judgment on whether it is more likely than not (a likelihood of more than 50%) that a portion or all of the deferred tax assets will not be realized. To determine whether a valuation allowance is needed, we consider all available evidence, both positive and negative, including carrybacks, tax planning strategies, reversals of deferred tax assets and liabilities and forecasted future taxable income. To determine the amount of financial statement benefit recorded for uncertain tax positions, we consider the amounts and probabilities of outcomes that could be realized upon ultimate settlement of an uncertain tax position using facts, circumstances and information available at the reporting date. To the extent that a valuation allowance or uncertain tax position is established or increased or decreased during a period, we record an expense or benefit in income tax expense in our Statements of Consolidated Operations. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. A change to future taxable income or tax planning strategies could impact our ability to utilize deferred tax assets, which would increase or decrease our income tax expense and taxes paid.

*Derivative Instruments.* We enter into derivative commodity instrument contracts primarily to reduce exposure to commodity price risk associated with future sales of natural gas production.

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

We believe derivative instruments are "critical accounting estimates" because our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments due to the volatility of both NYMEX natural gas prices and basis. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. Refer to Item 7A., "Quantitative and Qualitative Disclosures about Market Risk" for discussion of a hypothetical increase or decrease of 10% in the market price of natural gas.

*Contingencies and Asset Retirement Obligations.* We are involved in various legal and regulatory proceedings that arise in the ordinary course of business. We record a liability for contingencies based on our assessment that a loss is probable and the amount of the loss can be reasonably estimated. We consider many factors in making these assessments, including historical experience and matter specifics. Estimates are developed in consultation with legal counsel and are based on an analysis of potential results.

We accrue a liability for asset retirement obligations based on an estimate of the amount and timing of settlement. For oil and gas wells, the fair value of our plugging and abandonment obligations is recorded at the time the obligation is incurred, which is typically at the time the well is spud.

We believe contingencies and asset retirement obligations are "critical accounting estimates" because we must assess the probability of loss related to contingencies and the expected amount and timing of asset retirement obligation settlement. In addition, we must determine the estimated present value of future liabilities. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. If we incur losses related to contingencies that are higher than we expect, we could incur additional costs to settle such obligations. If the expected amount and timing of our asset retirement obligations change, we will be required to adjust the carrying value of our liabilities in future periods.

*Contract Asset.* In the first quarter of 2020, we entered into two share purchase agreements with Equitrans Midstream to sell to Equitrans Midstream 50% of our ownership of Equitrans Midstream's common stock in exchange for a combination of cash and rate relief under certain of our gathering agreements with EQM, an affiliate of Equitrans Midstream. The rate relief was effected through the execution the Consolidated GGA (defined and discussed in Note 5 to the Consolidated Financial Statements). We recorded a contract asset representing the estimated fair value of the rate relief provided by the Consolidated GGA. Key assumptions used in the fair value calculation included an estimated production volume forecast, a market-based discount rate and a probability-weighted estimate of the in-service date of the Mountain Valley Pipeline. Beginning with the Mountain Valley Pipeline in-service date, we will recognize amortization of the contract asset over a period of approximately four years in a manner consistent with the expected timing of our realization of the economic benefits of the rate relief provided by the Consolidated GGA.

We believe the Consolidated GGA contract asset is a "critical accounting estimate" because the assumptions used in the valuation of the contract asset involved significant judgment. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions. A change in the estimated production volume forecast, the market-based discount rate or the probability-weighted estimate of the in-service date of the Mountain Valley Pipeline could have resulted in a change in the valuation of the contract asset.

*Convertible Notes.* In the second quarter of 2020, we issued the Convertible Notes (defined and discussed in Note 10 to the Consolidated Financial Statements).

At issuance, we separated the Convertible Notes into liability and equity components. The carrying amount of the liability component was calculated by measuring the fair value of similar debt instruments that do not have associated convertible features. The carrying amount of the equity component, representing the conversion option, was determined by deducting the fair value of the liability component from the principal value of the Convertible Notes. The equity component is not remeasured as long as it continues to meet the condition for equity classification. The excess of the principal amount of the liability component over its carrying amount (the debt discount) will be amortized to interest expense over the term of the Convertible Notes using the effective interest rate method. Issuance costs were allocated to the liability and equity components of the Convertible Notes based on their relative fair values.

In connection with the Convertible Notes offering, we entered into the Capped Call Transactions (defined and discussed in Note 10 to the Consolidated Financial Statements). The Capped Call Transactions are separate from the Convertible Notes. The Capped Call Transactions were recorded in shareholders' equity and were not accounted for as derivatives. The cost to purchase the Capped Call Transactions was recorded as a reduction to equity and will not be remeasured.

Upon conversion of the Convertible Notes, we intend to use a combined settlement approach to satisfy our settlement obligation by paying or delivering to holders of the Convertible Notes cash equal to the principal amount of the obligation and EQT common stock for amounts that exceed the principal amount of the obligation. As such, we used the treasury stock method for the diluted earnings per share (EPS) calculation, and there is no adjustment to the diluted EPS numerator for the cash-settled portion of the instrument.

We believe the accounting complexity of the Convertible Notes is a "critical accounting estimate" because we used judgment to determine the balance sheet classification, to determine the treatment of the Capped Call Transactions and to determine the existence of any derivatives that may require separate accounting under applicable accounting guidance. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions.

*Business Combinations.* Accounting for a business combination requires a company to record the identifiable assets and liabilities acquired at fair value.

In the fourth quarter of 2020, we completed the Chevron Acquisition. The most significant assumptions used in accounting for the Chevron Acquisition include those used to estimate the fair value of the oil and gas properties acquired, the acquired investment in midstream gathering assets and acquired contract liabilities. We calculated the fair value of the acquired proved oil and gas properties, including in-process wells, using a risk-adjusted after-tax discounted cash flow analysis that was based on the following key assumptions: future commodity prices, projections of estimated quantities of reserves, estimated future rates of production, projected reserve recovery factors, timing and amount of future development and operating costs and a weighted average cost of capital. We calculated the fair value of the acquired unproved properties using the guideline transaction method that was based on the following key assumptions: future development plans from a market participant perspective and value per undeveloped acre. We calculated the fair value of our investment in the midstream gathering assets primarily using a discounted cash flow analysis that was based on the following key assumptions: projected revenues, expenses and capital expenditures. We calculated the fair value of acquired contract liabilities using estimated future volumes and annual contract commitments calculated on a discounted basis that was based on the following key assumptions: estimated future volumes and market participant cost of debt.

We believe business combinations are "critical accounting estimates" because the valuation of acquired assets and liabilities involves significant judgment about future events. Future results of operations for any quarterly or annual period could be materially affected by changes in our assumptions.

#### **Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

*Commodity Price Risk and Derivative Instruments.* Our primary market risk exposure is the volatility of future prices for natural gas and NGLs. Due to the volatility of commodity prices, we are unable to predict future potential movements in the market prices for natural gas and NGLs at our ultimate sales points and, thus, cannot predict the ultimate impact of prices on our operations. Prolonged low, or significant, extended declines in, natural gas and NGLs prices could adversely affect, among other things, our development plans, which would decrease the pace of development and the level of our proved reserves. Increases in natural gas and NGLs 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. In addition, to the extent we have hedged our production at prices below the current market price, we will not benefit fully from an increase in the price of natural gas.

The overall objective of our hedging program is to protect cash flows from undue exposure to the risk of changing commodity prices. Our use of derivatives is further described in Note 3 to the Consolidated Financial Statements and "Commodity Risk Management" under "Capital Resources and Liquidity" in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations." Our OTC derivative commodity instruments are placed primarily with financial institutions and the creditworthiness of those institutions is regularly monitored. We primarily enter into derivative instruments to hedge forecasted sales of production. We also enter into derivative instruments to hedge basis and exposure to fluctuations in interest rates. Our use of derivative instruments is implemented under a set of policies approved by our Hedge and Financial Risk Committee and reviewed by our Board of Directors.

For derivative commodity instruments used to hedge our forecasted sales of production, which are at, for the most part, NYMEX natural gas prices, we set policy limits relative to the expected production and sales levels that are exposed to price risk. We have an insignificant amount of financial natural gas derivative commodity instruments for trading purposes.

The derivative commodity instruments we use are primarily swap, collar and option agreements. These agreements may require payments to, or receipt of payments from, counterparties based on the differential between two prices for the commodity. We use these agreements to hedge our NYMEX and basis exposure. We may also use other contractual agreements when executing our commodity hedging strategy. We monitor price and production levels on a continuous basis and make adjustments to quantities hedged as warranted.

A hypothetical decrease of 10% in the market price of natural gas on December 31, 2020 and 2019 would increase the fair value of our natural gas derivative commodity instruments by approximately \$501 million and \$389 million, respectively. A hypothetical increase of 10% in the market price of natural gas on December 31, 2020 and 2019 would decrease the fair value of our natural gas derivative commodity instruments by approximately \$495 million and \$395 million, respectively. For purposes of this analysis, we applied the 10% change in the market price of natural gas on December 31, 2020 and 2019 to our natural gas derivative commodity instruments as of December 31, 2020 and 2019 to calculate the hypothetical change in fair value. The change in fair value was determined using a method similar to our normal process for determining derivative commodity instrument fair value described in Note 4 to the Consolidated Financial Statements.

The above analysis of our derivative commodity instruments does not include the offsetting impact that the same hypothetical price movement may have on our physical sales of natural gas. The portfolio of derivative commodity instruments held to hedge our forecasted produced gas approximates a portion of our expected physical sales of natural gas; therefore, an adverse impact to the fair value of the portfolio of derivative commodity instruments held to hedge our forecasted production associated with the hypothetical changes in commodity prices referenced above should be offset by a favorable impact on our physical sales of natural gas, assuming that the derivative commodity instruments are not closed 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 market interest rates affect the amount of interest we earn on cash, cash equivalents and short-term investments and the interest rates we pay on borrowings on our credit facility and, prior to its full redemption on June 30, 2020, our Term Loan Facility. None of the interest we pay on our senior notes fluctuates based on changes to market interest rates. A 1% increase in interest rates on our borrowings on our credit facility and term loan facility during the year ended December 31, 2020 would have increased 2020 annual interest expense by approximately \$5 million. A 1% increase in interest rates on our borrowings under our credit facility, term loan facility and floating rate notes during the year ended December 31, 2019 would have increased 2019 annual interest expense by approximately \$14 million.

Interest rates on the Adjustable Rate Notes fluctuate based on changes to the credit ratings assigned to our senior notes by Moody's, S&P and Fitch. For a discussion of credit rating downgrade risk, see Item 1A., "Risk Factors – Our exploration and production operations have substantial capital requirements, and we may not be able to obtain needed capital or financing on satisfactory terms." Changes in interest rates affect the fair value of our fixed rate debt. See Note 10 to the Consolidated Financial Statements for further discussion of our debt and Note 4 to the Consolidated Financial Statements for a discussion of fair value measurements, including the fair value of our debt.

*Other Market Risks.* We are exposed to credit loss in the event of nonperformance by counterparties to our derivative contracts. This credit exposure is limited to derivative contracts with a positive fair value, which may change as market prices change. Our 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. We use various processes and analyses to monitor and evaluate our credit risk exposures, including monitoring current market conditions and counterparty credit fundamentals. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. To manage the level of credit risk, we enter into transactions primarily with financial counterparties that are of investment grade, enter into netting agreements whenever possible and may obtain collateral or other security.

Approximately 47%, or \$456 million, of our OTC derivative contracts outstanding at December 31, 2020 had a positive fair value. Approximately 75%, or \$718 million, of our OTC derivative contracts outstanding at December 31, 2019 had a positive fair value.

As of December 31, 2020, we were not in default under any derivative contracts and had no knowledge of default by any counterparty to our derivative contracts. During the year ended December 31, 2020, we made no adjustments to the fair value of our derivative contracts due to credit related concerns outside of the normal non-performance risk adjustment included in our established fair value procedure. We monitor market conditions that may impact the fair value of our derivative contracts.

We are exposed to the risk of nonperformance by credit customers on physical sales of natural gas, NGLs and oil. Revenues and related accounts receivable from our operations are generated primarily from the sale of produced natural gas, NGLs and oil to marketers, utilities and industrial customers located in the Appalachian Basin and in markets that are accessible through our transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States and Canada. We also contract with certain processors to market a portion of NGLs on our behalf.

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

**Item 8. Financial Statements and Supplementary Data**

	<b><u>Page Reference</u></b>
<a href="#">Reports of Independent Registered Public Accounting Firm</a>	<a href="#">60</a>
<a href="#">Statements of Consolidated Operations for each of the three years in the period ended December 31, 2020</a>	<a href="#">67</a>
<a href="#">Statements of Consolidated Comprehensive Income for each of the three years in the period ended December 31, 2020</a>	<a href="#">68</a>
<a href="#">Consolidated Balance Sheets as of December 31, 2020 and 2019</a>	<a href="#">69</a>
<a href="#">Statements of Consolidated Cash Flows for each of the three years in the period ended December 31, 2020</a>	<a href="#">70</a>
<a href="#">Statements of Consolidated Equity for each of the three years in the period ended December 31, 2020</a>	<a href="#">71</a>
<a href="#">Notes to Consolidated Financial Statements</a>	<a href="#">72</a>

## **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, 2020 and 2019, the related statements of consolidated operations, comprehensive income, cash flows and equity for each of the three years in the period ended December 31, 2020, and the related notes and the financial statement schedule listed in the Index at Item 15 (a) (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company at December 31, 2020 and 2019, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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, 2020, 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 17, 2021 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.

### **Critical Audit Matters**

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

***Depreciation, depletion and amortization ('DD&A') of proved oil and natural gas properties***

<i>Description of the Matter</i>	At December 31, 2020, the net book value of the Company's proved oil and natural gas properties was \$13,613 million, and depreciation, depletion and amortization (DD&A) expense was \$1,393 million for the year then ended. As described in Note 1, under the successful efforts method of accounting, DD&A is recorded on a cost center basis using the units-of-production method. Proved developed reserves, as estimated by the Company's internal engineers, are used to calculate depreciation of wells and related equipment and facilities and amortization of intangible drilling costs. Total proved reserves, also estimated by the Company's engineers, are used to calculate depletion on property acquisitions. Proved natural gas, natural gas liquids (NGLs) and oil reserve estimates are based on geological and engineering evaluations of in-place hydrocarbon volumes. Significant judgment is required by the Company's engineers in evaluating geological and engineering data when estimating proved natural gas, NGLs and oil reserves. Estimating reserves also requires the selection of inputs, including natural gas, NGLs and oil price assumptions, future operating and capital costs assumptions and tax rates by jurisdiction, among others. Because of the complexity involved in estimating natural gas, NGLs and oil reserves, management used independent engineers to audit the estimates prepared by the Company's internal engineers as of December 31, 2020. Auditing the Company's DD&A calculation is especially complex because of the use of the work of the internal engineers and the independent engineers and the evaluation of management's determination of the inputs described above used by the specialists in estimating proved natural gas, NGLs and oil reserves.
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<i>How We Addressed the Matter in Our Audit</i>	We obtained an understanding, evaluated the design and tested the operating effectiveness of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data provided to the specialists for use in estimating the proved natural gas, NGLs and oil reserves.
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Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company engineer primarily responsible for overseeing the preparation of the reserve estimates by the internal engineering staff and the independent engineers used to audit the estimates. In addition, we evaluated the completeness and accuracy of the financial data and inputs described above used by the specialists in estimating proved natural gas, NGLs and oil reserves by agreeing them to source documentation and we identified and evaluated corroborative and contrary evidence. For proved undeveloped reserves, we evaluated management's development plan for compliance with the SEC rule that undrilled locations are scheduled to be drilled within five years, unless specific circumstances justify a longer time, by assessing consistency of the development projections with the Company's drill plan and the availability of capital relative to the drill plan. We also tested the mathematical accuracy of the DD&A calculations, including comparing the proved natural gas, NGLs and oil reserves amounts used to the Company's reserve report.

***Accounting for the Equitrans gas gathering agreement***

<i>Description of the Matter</i>	As more fully described in Note 5 to the consolidated financial statements, on February 26, 2020, the Company entered into the Share Purchase Agreements and the Consolidated Gas Gathering Agreement (the Consolidated GGA) pursuant to which, among other things, the Company sold to Equitrans Midstream 50% of its ownership of Equitrans Midstream's common stock in exchange for approximately \$52 million in cash and rate relief under certain of the Company's gathering contracts with EQM, an affiliate of Equitrans Midstream. The Consolidated GGA provides for additional cash bonus payments (the Henry Hub Cash Bonus) payable by the Company to EQM conditioned upon the quarterly average of the NYMEX Henry Hub natural gas settlement price exceeding certain price thresholds during a specified period. The Company's initial entry to record this transaction included recognition of a contract asset representing the estimated fair value of the rate relief provided by the Consolidated GGA of \$410 million and a derivative liability related to the Henry Hub Cash Bonus of approximately \$117 million. The determination of fair value of these components included significant judgment and assumptions by management, including an estimated production volume forecast, future commodity prices and price volatility, and a market-based discount rate.
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Auditing the Company's initial accounting for the Consolidated GGA contract asset and Henry Hub Cash Bonus derivative liability involved a high degree of subjectivity as the determination of fair values was based on assumptions as described above about future market and economic conditions. Additionally, a detailed analysis of the terms of the relevant agreements was required to determine the existence of any derivatives that may require separate accounting under applicable accounting guidance.

<i>How We Addressed the Matter in Our Audit</i>	We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Company's accounting for the Consolidated GGA. For example, we tested controls over management's assessment of the appropriateness of the significant assumptions outlined above that are inputs to the fair value calculations. We also tested management's evaluation of the Consolidated GGA and the identification and evaluation of specific features and the related accounting.
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To test the initial accounting for the Consolidated GGA, our audit procedures included, among others, inspection of the underlying agreement and testing management's application of the relevant accounting guidance, including the determination of the balance sheet classification of each transaction component and the identification of any derivatives included in the arrangements. We involved professionals with specialized skill and knowledge to assist in evaluating the appropriateness of the accounting for the Consolidated GGA, including conclusions reached with respect to identification and bifurcation of embedded features. Our testing of the Company's estimate of fair value of the contract asset and derivative liability related to the Henry Hub option included, among other procedures, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data. The audit effort involved the use of our valuation specialists to assist in evaluating the appropriateness of the methodology used in the cash flow models, as well as testing the significant market-related assumptions, such as future commodity prices and the market-based discount rate, used to develop the fair value estimates.

### **Convertible Notes Issuance**

<i>Description of the Matter</i>	As described in Note 10 to the consolidated financial statements, in April 2020, the Company issued \$500 million of aggregate principal of 1.75% convertible senior notes due May 2026 in a private offering to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended. Additionally, the Company entered into separate capped call transactions to reduce potential dilution to the Company's common stock upon any conversion of the Convertible Notes. These transactions are collectively referred to as the Convertible Notes Transactions. To account for the Convertible Notes, the Company was required to separate the Convertible Notes into liability and equity components. The carrying amount of the liability component was calculated by measuring the fair value of similar debt instruments that do not have an associated conversion feature. The carrying amount of the equity component was determined by deducting the fair value of the liability component from the principal value of the Convertible Notes.
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Auditing the Company's accounting for the Convertible Notes Transactions was complex due to the judgment that was required in determining the balance sheet classification of the elements of the Convertible Notes. Additionally, a detailed analysis of the terms of the Convertible Notes Transactions was required to determine the existence of any derivatives that may require separate accounting under applicable accounting guidance.

<i>How We Addressed the Matter in Our Audit</i>	We obtained an understanding, evaluated the design and tested the operating effectiveness of controls over the Convertible Notes Transactions. For example, we tested the Company's controls over the initial recognition and measurement of the Convertible Notes Transactions, including the recording of the associated liability and equity components. We also tested the evaluation of the Convertible Notes and the identification and evaluation of specific features and the related accounting.
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To test the initial accounting for the Convertible Notes Transactions, our audit procedures included, among others, inspection of the agreements underlying the Convertible Notes Transactions and testing management's application of the relevant accounting guidance, including the determination of the balance sheet classification of each transaction and the identification of any derivatives included in the arrangements. We involved professionals with specialized skill and knowledge to assist in evaluating the appropriateness of the accounting for the convertible notes, including conclusions reached with respect to identification and bifurcation of embedded features.

***Valuation of Acquired Proved Reserves***

*Description of the Matter* As described in Note 6 to the consolidated financial statements, the Company completed the acquisition of the Appalachian assets of Chevron U.S.A. during the year ended December 31, 2020. The Company's accounting for the acquisition included determining the fair value of the acquired proved reserves. The determination of fair value of the acquired proved reserves included significant judgment and assumptions by management, including future commodity prices, anticipated production volumes, future operating costs, and a weighted average cost of capital (WACC).

Auditing the Company's valuation of acquired proved reserves involved a high degree of subjectivity as the determination of fair value was based on assumptions as described above about future market and economic conditions. In addition, the certain of the assumptions developed by the Company's engineering staff in conjunction with the reserve estimates described in the preceding critical audit matter, are used as inputs in the cash flow model.

*How We Addressed the Matter in Our Audit* We obtained an understanding, evaluated the design, and tested the operating effectiveness of controls over the Company's process to estimate fair value for the acquired proved reserves. For example, we tested controls over management's assessment of the appropriateness of the significant assumptions that are inputs to the fair value calculation and management's review of the valuation model.

Our audit procedures included, among others, evaluating the professional qualifications and objectivity of the Company engineer primarily responsible for overseeing the preparation of the reserve estimates by the internal engineering staff, the independent engineers used to audit the estimates, and the external valuation specialist used to assist with the determination of the fair value of certain acquired assets. Our testing of the Company's estimate of fair value of the acquired proved reserves included, among other procedures, evaluating the significant assumptions used and testing the completeness and accuracy of the underlying data. The audit effort involved the use of our valuation specialists to assist in evaluating the appropriateness of the methodology used in the cash flow model, as well as testing the significant market-related assumptions described above used to develop the fair value estimate. We evaluated the reasonableness of management's assumptions by comparing the key market-related assumptions (including future natural gas prices and WACC rates) used in the cash flow model to external market and third-party data and anticipated production volumes to the reserve estimates audited by the independent engineers.

/s/ Ernst & Young LLP

We have served as the Company's auditor since 1950.

Pittsburgh, Pennsylvania

February 17, 2021

## **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, 2020, 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, 2020, based on the COSO criteria.

As indicated in the accompanying Management's Report on Internal Control over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of the assets acquired in the Chevron Acquisition, which are included in the 2020 consolidated financial statements of the Company and constituted 5% of total assets, as of December 31, 2020, and less than 1% of consolidated total operating revenues, for the year ended December 31, 2020. Our audit of internal control over financial reporting of the Company also did not include an evaluation of the internal control over financial reporting of assets acquired in the Chevron Acquisition.

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, 2020 and 2019, 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, 2020 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 17, 2021 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 17, 2021

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

	2020	2019	2018
	(Thousands, except per share amounts)		
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	\$ 2,650,299	\$ 3,791,414	\$ 4,695,519
Gain (loss) on derivatives not designated as hedges	400,214	616,634	(178,591)
Net marketing services and other	8,330	8,436	40,940
Total operating revenues	3,058,843	4,416,484	4,557,868
Operating expenses:			
Transportation and processing	1,710,734	1,752,752	1,697,001
Production	155,403	153,785	195,775
Exploration	5,484	7,223	6,765
Selling, general and administrative	174,769	170,611	232,543
Depreciation and depletion	1,393,465	1,538,745	1,569,038
Amortization of intangible assets	26,006	35,916	41,367
Impairment/loss on sale/exchange of long-lived assets	100,729	1,138,287	2,709,976
Impairment of intangible and other assets	34,694	15,411	—
Impairment of goodwill	—	—	530,811
Impairment and expiration of leases	306,688	556,424	279,708
Other operating expenses	28,537	199,440	78,008
Total operating expenses	3,936,509	5,568,594	7,340,992
Operating loss	(877,666)	(1,152,110)	(2,783,124)
Gain on Equitrans Share Exchange (see Note 5)	(187,223)	—	—
Loss on investment in Equitrans Midstream Corporation	314,468	336,993	72,366
Dividend and other income	(35,512)	(91,483)	(7,017)
Loss on debt extinguishment	25,435	—	—
Interest expense	271,200	199,851	228,958
Loss from continuing operations before income taxes	(1,266,034)	(1,597,471)	(3,077,431)
Income tax benefit	(298,858)	(375,776)	(696,511)
Loss from continuing operations	(967,176)	(1,221,695)	(2,380,920)
Income from discontinued operations, net of tax	—	—	373,762
Net loss	(967,176)	(1,221,695)	(2,007,158)
Less: Net loss attributable to noncontrolling interest	(10)	—	—
Less: Net income from discontinued operations attributable to noncontrolling interests	—	—	237,410
Net loss attributable to EQT Corporation	\$ (967,166)	\$ (1,221,695)	\$ (2,244,568)
Amounts attributable to EQT Corporation:			
Loss from continuing operations	\$ (967,166)	\$ (1,221,695)	\$ (2,380,920)
Income from discontinued operations, net of tax	—	—	136,352
Net loss	\$ (967,166)	\$ (1,221,695)	\$ (2,244,568)
Loss per share of common stock attributable to EQT Corporation:			
Basic and diluted:			
Weighted average common stock outstanding	260,613	255,141	260,932
Loss from continuing operations	\$ (3.71)	\$ (4.79)	\$ (9.12)
Income from discontinued operations	—	—	0.52
Net loss	\$ (3.71)	\$ (4.79)	\$ (8.60)

The accompanying notes are an integral part of these Consolidated Financial Statements.

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

	2020	2019	2018
	(Thousands)		
Net loss	\$ (967,176)	\$ (1,221,695)	\$ (2,007,158)
Other comprehensive (loss) income, net of tax:			
Net change in cash flow hedges:			
Natural gas, net of tax expense: \$2,584 in 2018	—	—	(4,625)
Interest rate, net of tax expense: \$210 in 2019 and \$80 in 2018	—	387	168
Other postretirement benefits liability adjustment, net of tax (benefit) expense: \$(36), \$150 and \$510	(156)	316	606
Change in accounting principle	—	(496)	—
Other comprehensive (loss) income	(156)	207	(3,851)
Comprehensive loss	(967,332)	(1,221,488)	(2,011,009)
Less: Comprehensive loss attributable to noncontrolling interest	(10)	—	—
Less: Comprehensive income from discontinued operations attributable to noncontrolling interests	—	—	237,410
Comprehensive loss attributable to EQT Corporation	\$ (967,322)	\$ (1,221,488)	\$ (2,248,419)

The accompanying notes are an integral part of these Consolidated Financial Statements.

**EQT CORPORATION AND SUBSIDIARIES**  
**CONSOLIDATED BALANCE SHEETS**  
**DECEMBER 31,**

	2020	2019
	(Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 18,210	\$ 4,596
Accounts receivable (less provision for doubtful accounts: \$6,239 and \$6,861)	566,552	610,088
Derivative instruments, at fair value	527,073	812,664
Income tax receivable	—	298,854
Prepaid expenses and other	103,615	28,653
Total current assets	1,215,450	1,754,855
Property, plant and equipment		
Less: Accumulated depreciation and depletion	5,940,984	5,499,861
Net property, plant and equipment	16,054,265	16,155,490
Contract asset		
Investment in Equitrans Midstream Corporation	203,380	676,009
Other assets	230,374	222,873
Total assets	\$ 18,113,469	\$ 18,809,227
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Current portion of debt	\$ 154,161	\$ 16,204
Accounts payable	705,461	796,438
Derivative instruments, at fair value	600,877	312,696
Other current liabilities	301,911	220,564
Total current liabilities	1,762,410	1,345,902
Credit facility borrowings		
Term Loan Facility borrowings	—	999,353
Senior notes	4,371,467	3,878,366
Note payable to EQM Midstream Partners, LP	99,838	105,056
Deferred income taxes	1,371,967	1,485,814
Other liabilities and credits	945,057	897,148
Total liabilities	8,850,739	9,005,639
Shareholders' equity:		
Common stock, no par value, shares authorized: 640,000 and 320,000, shares issued: 280,003 and 257,003	8,241,684	7,818,205
Treasury stock, shares at cost: 1,658 and 1,832	(29,348)	(32,507)
Retained earnings	1,048,259	2,023,089
Accumulated other comprehensive loss	(5,355)	(5,199)
Total common shareholders' equity	9,255,240	9,803,588
Noncontrolling interests in consolidated subsidiaries	7,490	—
Total equity	9,262,730	9,803,588
Total liabilities and shareholders' equity	\$ 18,113,469	\$ 18,809,227

The accompanying notes are an integral part of these Consolidated Financial Statements.

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

	2020	2019	2018
	(Thousands)		
<b>Cash flows from operating activities:</b>			
Net loss	\$ (967,176)	\$ (1,221,695)	\$ (2,007,158)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Deferred income tax expense (benefit)	(155,840)	(275,063)	(510,405)
Depreciation and depletion	1,393,465	1,538,745	1,729,739
Amortization of intangible assets	26,006	35,916	77,374
Impairment/loss on sale/exchange of long-lived assets and leases	442,111	1,710,122	2,989,684
Gain on Equitrans Share Exchange	(187,223)	—	—
Impairment of goodwill	—	—	798,689
Loss on investment in Equitrans Midstream Corporation	314,468	336,993	72,366
Loss on debt extinguishment	25,435	—	—
Share-based compensation expense	19,552	31,233	25,189
Amortization, accretion and other	37,414	23,296	(33,039)
(Gain) loss on derivatives not designated as hedges	(400,214)	(616,634)	178,591
Cash settlements received (paid) on derivatives not designated as hedges	897,190	246,639	(225,279)
Net premiums (paid) received on derivative instruments	(46,665)	22,616	—
Changes in other assets and liabilities:			
Accounts receivable	(36,296)	432,323	(439,062)
Accounts payable	(29,193)	(238,674)	457,113
Income tax receivable and payable	322,763	(167,281)	(117,188)
Other current assets	(68,628)	54,776	(28,256)
Other items, net	(49,468)	(61,608)	7,898
Net cash provided by operating activities	1,537,701	1,851,704	2,976,256
<b>Cash flows from investing activities:</b>			
Capital expenditures	(1,042,231)	(1,602,454)	(2,999,037)
Cash paid for acquisitions (see Note 6)	(691,942)	—	—
Capital expenditures for discontinued operations	—	—	(732,727)
Capital contributions to Mountain Valley Pipeline, LLC	—	—	(820,943)
Proceeds from sale of assets	126,080	—	583,381
Cash received for Equitrans Share Exchange	52,323	—	—
Other investing activities	(30)	1,312	(9,778)
Net cash used in investing activities	(1,555,800)	(1,601,142)	(3,979,104)
<b>Cash flows from financing activities:</b>			
Net proceeds from issuance of common stock	340,923	—	—
Proceeds from borrowings on credit facility	3,118,250	2,978,750	8,637,500
Repayment of borrowings on credit facility	(3,112,250)	(3,484,750)	(8,953,500)
Proceeds from issuance of debt	2,600,000	1,000,000	2,500,000
Debt issuance costs and Capped Call Transactions (See Note 10)	(71,056)	(913)	(40,966)
Repayments and retirements of debt	(2,822,262)	(704,661)	(8,376)
Premiums paid on debt extinguishment	(21,132)	—	—
Dividends paid	(7,664)	(30,655)	(31,375)
Proceeds and excess tax benefits from awards under employee compensation plans	—	—	1,946
Cash paid for taxes related to net settlement of share-based incentive awards	(596)	(7,224)	(22,647)
Repurchase and retirement of common stock	—	—	(538,876)
Repurchase of common stock	—	—	(27)
Contributions from (distributions to) noncontrolling interests	7,500	—	(380,651)
Acquisition of 25% of Strike Force Midstream LLC	—	—	(175,000)
Net cash transferred at Separation and Distribution	—	—	(129,008)
Net cash provided by (used in) financing activities	31,713	(249,453)	859,020
Net change in cash and cash equivalents	13,614	1,109	(143,828)
Cash and cash equivalents at beginning of year	4,596	3,487	147,315
Cash and cash equivalents at end of year	\$ 18,210	\$ 4,596	\$ 3,487

The accompanying notes are an integral part of these Consolidated Financial Statements.  
See Note 1 for supplemental cash flow information. See Note 8 for discontinued operations cash flow information.

**EQT CORPORATION AND SUBSIDIARIES**  
**STATEMENTS OF CONSOLIDATED EQUITY**  
**YEARS ENDED DECEMBER 31, 2020, 2019 and 2018**

	Common Stock		Treasury Stock	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests in Consolidated Subsidiaries	Total Equity
	Shares	No Par Value					
(Thousands, except per share or unit amounts)							
<b>Balance at December 31, 2017</b>	264,320	\$ 9,388,903	\$ (63,602)	\$ 3,996,775	\$ (2,458)	\$ 5,094,995	\$ 18,414,613
Comprehensive (loss) 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: \$2,584					(4,625)		(4,625)
Interest rate, net of tax: \$80					168		168
Other postretirement benefits liability adjustment, net of tax: \$510					606		606
Dividends (\$0.12 per share)				(31,375)			(31,375)
Share-based compensation plans, net	798	(6,976)	14,408			953	8,385
Distributions to noncontrolling interests in discontinued operations (a)						(380,651)	(380,651)
Change in accounting principle				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)
<b>Balance at December 31, 2018</b>	254,472	\$ 7,828,554	\$ (49,194)	\$ 3,184,275	\$ (5,406)	\$ —	\$ 10,958,229
Comprehensive (loss) income, net of tax:							
Net loss				(1,221,695)			(1,221,695)
Net change in interest rate cash flow hedges, net of tax: \$210					387		387
Other postretirement benefits liability adjustment, net of tax: \$150					316		316
Dividends (\$0.12 per share)				(30,655)			(30,655)
Share-based compensation plans	921	6,355	16,687				23,042
Change in accounting principle				496	(496)		—
Distribution of Equitrans Midstream Corporation (see Note 9)		(2,234)		93,123			90,889
Other	(222)	(14,470)		(2,455)			(16,925)
<b>Balance at December 31, 2019</b>	255,171	\$ 7,818,205	\$ (32,507)	\$ 2,023,089	\$ (5,199)	\$ —	\$ 9,803,588
Comprehensive loss, net of tax:							
Net loss				(967,166)		(10)	(967,176)
Other postretirement benefits liability adjustment, net of tax: \$(36)					(156)		(156)
Dividends (\$0.03 per share)				(7,664)			(7,664)
Share-based compensation plans	174	18,911	3,159				22,070
Equity component of convertible senior notes (see Note 10)		63,645					63,645
Issuance of common shares	23,000	340,923					340,923
Contributions from noncontrolling interests						7,500	7,500
<b>Balance at December 31, 2020</b>	278,345	\$ 8,241,684	\$ (29,348)	\$ 1,048,259	\$ (5,355)	\$ 7,490	\$ 9,262,730

Common shares authorized: 320,000 at December 31, 2018 and 2019 and 640,000 at December 31, 2020.

Preferred shares authorized: 3,000. There were no preferred shares issued or outstanding.

- (a) For the year ended December 31, 2018, distributions to noncontrolling interests were \$4.295, \$1.123 and \$0.5966 per common unit for EQM Midstream Partners, LP, EQGP Holdings, LP and RM Partners LP, respectively.

The accompanying notes are an integral part of these Consolidated Financial Statements.

**EQT CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**DECEMBER 31, 2020**

**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 EQT holds a controlling interest (collectively, EQT or the Company). Intercompany accounts and transactions have been eliminated in consolidation. The Company records noncontrolling interest in its Consolidated Financial Statements for any non-wholly-owned consolidated subsidiary.

*Investment in Consolidated Partnership.* In the fourth quarter of 2020, the Company entered into a partnership with a third-party investor (the Partnership). Because the Company has the power to direct the activities that most significantly affect the Partnership's economic performance, the Company consolidates the Partnership. The Company presents noncontrolling interest in the Partnership as a component of equity in the Consolidated Balance Sheet and an allocation of earnings attributable to the noncontrolling interest in the Statement of Consolidated Operations.

*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 and located in the United States.

*Reclassification.* Certain previously reported amounts have been reclassified to conform to the current year presentation.

*Discontinued Operations.* For businesses classified as discontinued operations, balance sheet amounts and results of operations are reclassified from their historical presentation to assets and liabilities of discontinued operations in the Consolidated Balance Sheet and discontinued operations on the Statement of Consolidated Operations, respectively. The Statement of Consolidated Cash Flows was not reclassified for discontinued operations. See Note 8.

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

*Accounts Receivable.* The Company's accounts receivable relates primarily to the sales of natural gas, natural gas liquids (NGLs) and oil and amounts due from joint interest partners. See Note 2 for a discussion of amounts due from contracts with customers.

*Derivative Instruments.* See Note 3 for a discussion of the Company's derivative instruments and Note 4 for a discussion of the Company's fair value hierarchy and fair value measurements.

*Prepaid Expenses and Other.* The following table summarizes the Company's prepaid expenses and other current assets.

	<b>December 31,</b>	
	<b>2020</b>	<b>2019</b>
	<b>(Thousands)</b>	
Margin requirements with counterparties (See Note 3)	\$ 82,552	\$ 12,606
Prepaid expenses and other current assets	21,063	16,047
Total prepaid expenses and other	<u>\$ 103,615</u>	<u>\$ 28,653</u>

*Property, Plant and Equipment.* The following table summarizes the Company's property, plant and equipment.

	December 31,	
	2020	2019
	(Thousands)	
Oil and gas producing properties, successful efforts method	\$ 21,771,025	\$ 21,316,834
Less: Accumulated depreciation and depletion	5,866,418	5,402,515
Net oil and gas producing properties	15,904,607	15,914,319
Other properties, at cost less accumulated depreciation	149,658	241,171
Net property, plant and equipment	\$ 16,054,265	\$ 16,155,490

The Company uses the successful efforts method of accounting for gas, NGL and oil producing activities. Under this method, the cost of productive wells and related equipment, development dry holes and productive acreage, including productive mineral interests, are capitalized and depleted using the unit-of-production method. These costs include salaries, benefits and other internal costs directly attributable to production activities. The Company capitalized internal costs of approximately \$51 million, \$77 million and \$130 million in 2020, 2019 and 2018, respectively. The Company also capitalized interest expense related to well development of approximately \$17 million, \$24 million and \$29 million in 2020, 2019 and 2018, respectively. Depletion expense is calculated based on actual produced sales volumes multiplied by the applicable depletion rate per unit. Depletion rates for leases and wells are each calculated by dividing net capitalized costs by the number of units expected to be produced over the life of the reserves separately. Costs for exploratory dry holes, exploratory geological and geophysical activities and delay rentals as well as other property carrying costs are charged to exploration expense. The Company's producing oil and gas properties had an overall average depletion rate of \$0.92, \$1.01 and \$1.04 per Mcfe for the years ended December 31, 2020, 2019 and 2018, respectively.

There were no exploratory wells drilled during 2020, 2019 and 2018, and there were no capitalized exploratory well costs for the years ended December 31, 2020, 2019 and 2018.

*Impairment of Long-lived Assets.* 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. To determine whether impairment of the Company's oil and gas properties has occurred, the Company compares the estimated expected undiscounted future cash flows to the carrying values of those properties. Estimated future cash flows are based on proved and, if determined reasonable by management, risk-adjusted probable reserves and assumptions generally consistent with the assumptions used by the Company 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 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 rates and other assumptions that marketplace participants would use in their fair value estimates.

There were no indicators of impairment identified in 2020.

During the fourth quarter of 2019, there were indicators that the carrying values of certain of the Company's properties may be impaired due to depressed natural gas prices and changes in the Company's development strategy, including the Company's contemplation of a potential asset divestiture of certain of its non-strategic exploration and production assets. As a result of the 2019 impairment evaluation, the Company recorded total impairment of \$1,124.4 million, of which \$1,035.7 million was associated with the Company's non-strategic assets located in the Ohio Utica and \$88.7 million was associated with the Company's Pennsylvania and West Virginia Utica assets. The impairment was recorded as a reduction to the assets' carrying values to their estimated fair values of approximately \$839.4 million with respect to the Company's Ohio Utica assets and approximately \$26.8 million with respect to the Company's Pennsylvania and West Virginia Utica assets. The fair value of the impaired assets, as determined at December 31, 2019, was based on significant inputs that are not observable in the market and, as such, are considered a Level 3 fair value measurement. See Note 4 for a description of the fair value hierarchy. Key assumptions included in the calculation of the fair value included the following: (i) reserves, including risk adjustments for probable reserves; (ii) future commodity prices; (iii) to the extent available, market-based indicators of fair value, including estimated proceeds that could be realized upon a potential disposition; (iv) production rates based on the Company's experience with similar properties; (v) future operating and development costs; (vi) inflation and (vii) a market-based weighted average cost of capital.

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 the Company's intention to sell its Huron and Permian assets before the end of their useful lives. As a result of

the 2018 impairment evaluation, the Company recorded impairment of \$2.4 billion associated with the Company's Huron and Permian assets. See Note 7 for discussion of the Huron and Permian assets divestitures.

*Impairment and Expiration of Leases.* Capitalized costs of unproved oil and gas properties are evaluated for recoverability on a prospective basis at least annually. Indicators of potential impairment include changes due to economic factors, potential shifts in business strategy 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. If the Company does not intend to drill on the property prior to expiration of the lease or does not have the intent and ability to extend, renew, trade or sell the lease prior to expiration, impairment expense is recorded. Expense for lease expirations where the lease was not previously impaired is recorded as the lease expires. For the years ended December 31, 2020, 2019 and 2018, the Company recorded \$306.7 million, \$556.4 million and \$279.7 million, respectively, for lease impairments and expirations. The Company's unproved properties had a net book value of approximately \$2,292 million and \$3,322 million at December 31, 2020 and 2019, respectively.

*Goodwill.* Goodwill is the cost of an acquisition less the fair value of the identifiable net assets of the acquired business. Goodwill is tested for impairment at the Company's single reporting unit level on at least an annual basis or if events or circumstances indicate that it is more likely than not that the fair value of its reporting unit is below its carrying value. The Company considers market capitalization and other valuation techniques, as applicable, when estimating fair value for goodwill impairment testing purposes.

In connection with the 2018 annual goodwill impairment test, the Company identified several qualitative factors that are generally considered when assessing goodwill for impairment, including 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, the Company's excess capital spend compared to the capital budget announced in October 2018, the recent operational volume curtailments and the Company's strategy to slow the cadence of its future drilling operations.

The Company performed the first step of the goodwill impairment test for its single reporting unit as of November 30, 2018. The Company used its market capitalization plus a control premium to estimate fair value for its single reporting unit. Estimated market capitalization was calculated by multiplying the Company's 30-day weighted average stock price and the number of outstanding common stock of the Company (EQT common stock) as of November 30, 2018. The reporting unit's estimated fair value was significantly less than its carrying value and, as such, all of the goodwill was impaired. This impairment charge was classified as a component of operating expenses.

*Contract Asset.* See Note 5 for discussion of the Company's contract asset.

The carrying value of the Company's contract asset is reviewed for impairment when events or circumstances indicate that the remaining carrying value may not be recoverable. To determine whether impairment of the Company's contract asset has occurred, the Company compares the estimated undiscounted future cash flows to the carrying value. Estimated future cash flows are based on the estimated volumes and the in-service date of the Mountain Valley Pipeline. If the contract asset's carrying amount exceeds the estimated future undiscounted cash flows, it is 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 fair value estimates.

During 2020, the Company identified indicators that the carrying value of the contract asset may not be fully recoverable due to further delays of the timing of completion of the Mountain Valley Pipeline as well as changes to the regulatory landscape. The Company performed the first step of the impairment test and determined the estimated expected undiscounted future cash flows exceeded the carrying value of the contract asset, indicating the contract asset was not impaired. The estimated undiscounted future cash flows were based on significant inputs that are not observable in the market and, as such, are considered a Level 3 fair value measurement. See Note 4 for a description of the fair value hierarchy. Key assumptions in the calculation of estimated undiscounted future cash flows included estimated production volumes subject to the Consolidated GGA (defined in Note 5 to the Consolidated Financial Statements) and a probability-weighted estimate of the in-service date of the Mountain Valley Pipeline.

*Investment in Equitrans Midstream Corporation.* As of December 31, 2020, the Company owned approximately 25 million 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, its investment in Equitrans Midstream is accounted for as an investment in equity securities and recorded at fair value in the Consolidated Balance Sheets. The fair value is calculated by multiplying the closing stock price of Equitrans Midstream's common stock by the number of shares of Equitrans Midstream's common stock owned by the Company. Changes

in fair value are recorded in loss on investment in Equitrans Midstream Corporation in the Statements of Consolidated Operations. See Note 4 for a description of the fair value hierarchy. Dividends received on the investment in Equitrans Midstream are recorded in dividend and other income in the Statements of Consolidated Operations. See Note 5 and Note 8.

**Intangible Assets.** The Company's intangible assets were recorded under the acquisition method of accounting at their estimated fair values at the acquisition date of Rice Energy Inc. (Rice Energy). The Company's intangible assets were composed of non-compete agreements with former Rice Energy executives. The non-compete agreements had a useful life of 3 years. The Company calculates amortization on a straight-line basis over the estimated useful life of the intangible assets. The Company's intangible assets were fully amortized as of December 31, 2020.

The following table summarizes the Company's intangible assets.

	December 31,	
	2020	2019
	(Thousands)	
Non-compete agreements	\$ 108,689	\$ 124,100
Less: Accumulated amortization	108,689	82,683
Less: Impairment of intangible assets (a)	—	15,411
Intangible assets, net	\$ —	\$ 26,006

(a) In 2019 the Company recognized impairment of its intangible assets associated with non-compete agreements for former Rice Energy executives who are now employees of the Company.

**Other Current Liabilities.** The following table summarizes the Company's other current liabilities.

	December 31,	
	2020	2019
	(Thousands)	
Accrued interest payable	\$ 91,953	\$ 36,590
Current portion of long-term capacity contracts	50,504	34,000
Taxes other than income	44,619	57,850
Incentive compensation	33,601	18,573
Current portion of operating lease liabilities	25,004	29,036
Income tax payable	23,909	—
Severance accrual	2,536	11,769
Other accrued liabilities	29,785	32,746
Total other current liabilities	\$ 301,911	\$ 220,564

**Unamortized Debt Discount and Issuance Expense.** Discounts and expenses incurred with the issuance of debt are amortized over the life of the debt. These amounts are presented as a reduction of senior notes in the Consolidated Balance Sheets. See Note 10.

**Income Taxes.** The Company files a consolidated U.S. federal income tax return and uses 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 year taxes made in the current year due to new 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 arise from temporary differences between the financial reporting and tax bases of the Company's 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 a portion or all of the deferred tax asset will not be realized.

In accounting for uncertainty of a tax position taken or expected to be taken in a tax return, the Company uses 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. If it is more likely than not that a tax position will be sustained, the Company measures and recognizes the tax position at the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Company recognizes accrued interest and penalties related to unrecognized tax benefits in income tax expense. See Note 9.

**Insurance.** The Company maintains insurance to cover traditional insurable risks such as general liability, workers compensation, auto liability, environmental liability, property damage, business interruption and other risks. These policies may be subject to deductible or retention amounts, coverage limitations and exclusions. The Company was previously self-insured for certain material losses related to general liability and certain other casualty coverages, such as workers compensation, auto liability and environmental liability. However, the Company is no longer self-insured with respect to any material losses related to general liability, workers compensation or environmental liability arising on or after November 12, 2020, or for losses related to auto liability arising on or after November 12, 2019. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. Reserves are estimated based on analyses of historical data and actuarial estimates and are not discounted. The liabilities are reviewed by the Company quarterly and by independent actuaries annually to ensure appropriateness. 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.

**Asset Retirement Obligations.** The Company accrues a liability for asset retirement obligations based on an estimate of the amount and timing of settlement. For oil and gas wells, the fair value of the Company's plugging and abandonment obligations is recorded at the time the obligation is incurred, which is typically at the time the well is 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 expense. 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 of plugging and abandoning wells and reclaiming or disposing other assets and 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 included in other liabilities and credits in the Consolidated Balance Sheets.

	December 31,	
	2020	2019
	(Thousands)	
Balance at January 1	\$ 461,821	\$ 287,805
Accretion expense	22,506	13,733
Liabilities incurred	10,293	8,985
Liabilities settled	(4,030)	(3,569)
Liabilities assumed in acquisitions	45,825	—
Liabilities removed due to divestitures	(54,836)	(5,535)
Change in estimates	41,978	160,402
Balance at December 31	\$ 523,557	\$ 461,821

The Company does not have any assets that are legally restricted for purposes of settling these obligations. During 2020 and 2019, the Company had changes in estimates for the plugging of horizontal and conventional wells that were related primarily to pad reclamation and increased cost assumptions for the Company's compliance with existing regulatory requirements that were derived, in part, from recent plugging experience and actual costs incurred. The Company operates in several states that have implemented expanded requirements that resulted in the Company's use of additional materials during the plugging process, which has increased the estimated cost for plugging horizontal and conventional wells.

**Revenue Recognition.** For information on revenue recognition from contracts with customers and gains and losses on derivative commodity instruments see Notes 2 and 3, respectively.

**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.

*Share-based Compensation.* See Note 13 for a discussion of the Company's share-based compensation plans.

*Provision for Doubtful Accounts.* Reserves for uncollectible accounts are recorded in selling, general and administrative expense in the Statements of Consolidated Operations. Judgment is required to assess the ultimate realization of the Company's accounts receivable. Reserves are based on historical experience, current and expected economic trends and specific information about customer accounts, such as the customer's creditworthiness.

*Other Operating Expenses.* The following table summarizes the Company's other operating expenses.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Changes in legal reserves, including settlements	\$ 11,350	\$ 82,395	\$ 51,677
Transactions	11,739	—	26,331
Reorganization, including severance and contract terminations	5,448	97,702	—
Proxy	—	19,343	—
Total other operating expenses	<u>\$ 28,537</u>	<u>\$ 199,440</u>	<u>\$ 78,008</u>

*Other Postretirement Benefits Plan.* The Company sponsors a plan for postretirement benefits plan. The Company recognized expense related to its defined contribution plan of \$6.5 million, \$8.9 million and \$17.3 million for the years ended December 31, 2020, 2019 and 2018, respectively.

*Earnings Per Share (EPS).* Basic EPS is computed by dividing net income attributable to EQT by the weighted average number of common shares outstanding during the period. Diluted EPS is 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. Potentially dilutive securities arise from the assumed conversion of outstanding stock options and other share-based awards as well as the conversion premium on the Convertible Notes. Purchases of treasury shares are calculated using the average share price of EQT common stock during the period.

In periods when the Company reports a net loss, all options, restricted stock, performance awards and stock appreciation rights are excluded from the calculation of diluted weighted average shares outstanding because of their anti-dilutive effect on loss per share. As a result, for the years ended December 31, 2020, 2019 and 2018, all securities, totaling 6,778,383, 3,035,247 and 2,211,122, respectively, were excluded from potentially dilutive securities because of their anti-dilutive effect on EPS.

As discussed in Note 10, the Company issued the Convertible Notes during the second quarter of 2020 and, upon conversion of the Convertible Notes, intends to use a combined settlement approach to satisfy its settlement obligation under the Convertible Notes. As such, there is no adjustment to the diluted EPS numerator for the cash-settled portion of the instrument. For the year ended December 31, 2020, the conversion premium of 6,666,670 shares was excluded from potentially dilutive securities because of its anti-dilutive effect on loss per share.

*Supplemental Cash Flow Information.* The following table summarizes net cash paid (received) for interest and income taxes and non-cash activity included in the Consolidated Statements of Cash Flows.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
<b>Cash paid (received) during the year for:</b>			
Interest, net of amount capitalized	\$ 195,681	\$ 198,562	\$ 260,959
Income taxes, net	(448,906)	(1,710)	(3,675)
<b>Non-cash activity during the period for:</b>			
Increase in asset retirement costs and obligations	\$ 52,271	\$ 169,387	\$ 34,602
Increase in right-of-use assets and lease liabilities, net	18,877	113,350	—
Capitalization of non-cash equity share-based compensation	3,142	—	4,314
Measurement period adjustments for prior period acquisitions	—	—	14,377

*Recently Issued Accounting Standards*

In June 2016, the Financial Accounting Standards Board (FASB) issued ASU 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 and requires entities to reflect their current estimate of all expected credit losses. The amendment affects loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables and any other financial assets not excluded from its scope that have a contractual right to receive cash. This ASU is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company adopted this ASU on January 1, 2020 with no changes to its methodology, financial statements or disclosures.

In July 2018, the FASB issued ASU 2018-07, *Improvements to Nonemployee Share-Based Payment Accounting*. This ASU expands the scope of Topic 718, *Compensation – Share Compensation*, to include share-based payment transactions where a grantor acquires goods or services from a nonemployee. This ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, and early adoption is permitted. The Company adopted this ASU on January 1, 2020 with no changes to its methodology, financial statements or disclosures.

In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement, Changes to the Disclosure Requirements for Fair Value Measurement*. This ASU modifies the hierarchy associated with Level 1, 2 and 3 fair value measurements and the related disclosure requirements. This ASU is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. The Company adopted this ASU on January 1, 2020 with no changes to its methodology, financial statements or disclosures.

In August 2018, the FASB issued ASU 2018-15, *Intangibles – Goodwill and Other – Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract*. This ASU provides guidance on accounting for implementation costs incurred by a customer in a cloud computing arrangement that is a service contract. This ASU is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted. The Company adopted this ASU prospectively on January 1, 2020, at which point onward applicable costs were capitalized to the Consolidated Balance Sheet rather than expensed to selling, general and administrative expense in the Statement of Consolidated Operations. For the year ended December 31, 2020, such capitalized costs were approximately \$9 million.

In December 2019, the FASB issued ASU 2019-12, *Income Taxes: Simplifying the Accounting for Income Taxes*. This ASU simplifies accounting for income taxes by eliminating certain exceptions to ASC 740, *Income Taxes*, related to the general approach for intraperiod tax allocation, methodology for calculating income taxes in an interim period and recognition of deferred taxes when there are investment ownership changes. In addition, this ASU simplifies aspects of accounting for franchise taxes and interim period effects of enacted changes in tax laws or rates and provides clarification on accounting for transactions that result in a step up in the tax basis of goodwill and allocation of consolidated income tax expense to separate financial statements of entities not subject to income tax. This ASU is effective for fiscal years beginning after December 15, 2020, including interim periods within those fiscal years, and early adoption is permitted. The Company plans to adopt this ASU in the first quarter of 2021 and does not expect this adoption to have a material impact on its financial statements and related disclosures.

In August 2020, the FASB issued ASU 2020-06, *Debt with Conversion and Other Options and Derivatives and Hedging: Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*. This ASU simplifies accounting for convertible instruments by removing certain separation models for convertible instruments. For convertible instruments with conversion features that are not accounted for as derivatives under ASC 815 or do not result in substantial premiums accounted for as paid-in capital, the convertible instrument's embedded conversion features are no longer separated from the host contract. Consequently, and as long as no other feature requires bifurcation and recognition as a derivative, the convertible instrument is accounted for as a single liability measured at its amortized cost. This ASU also amends the impact of convertible instruments on the calculation of diluted EPS and adds several new disclosure requirements. This ASU is effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. The Company plans to adopt this ASU on January 1, 2022 using the full retrospective method of adoption. The Company is evaluating the impact this standard will have on its financial statements and related disclosures.

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

## 2. Revenue from Contracts with Customers

Under the Company's natural gas, natural gas liquids (NGLs) and oil sales contracts, 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 commodity 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, such as fixed price contracts or contracts with a fixed differential to New York Mercantile Exchange (NYMEX) or index prices, contain fixed consideration. 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, NGLs and oil are satisfied at a point in time because the customer obtains control and legal title of the asset when the natural gas, NGLs or oil is delivered to the designated sales point.

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

For contracts with customers where the Company's performance obligations had been satisfied and an unconditional right to consideration existed as of the balance sheet date, the Company recorded amounts due from contracts with customers of \$394.1 million and \$384.0 million in accounts receivable in the Consolidated Balance Sheets as of December 31, 2020 and 2019, respectively.

The table below provides disaggregated information on the Company's revenues. Certain contracts that provide for the release of capacity that is not used to transport the Company's produced volumes are outside the scope of ASU 2014-09, *Revenue from Contracts with Customers*. The costs of, and recoveries on, such capacity are reported in net marketing services and other in the Statements of Consolidated Operations. Derivative contracts are also outside the scope of ASU 2014-09.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
<b>Revenues from contracts with customers:</b>			
Natural gas sales	\$ 2,459,854	\$ 3,559,809	\$ 4,217,684
NGLs sales	169,871	197,985	442,010
Oil sales	20,574	33,620	35,825
Net marketing services and other	—	—	13,865
Total revenues from contracts with customers	2,650,299	3,791,414	4,709,384
<b>Other sources of revenue:</b>			
Net marketing services and other	8,330	8,436	27,075
Gain (loss) on derivatives not designated as hedges	400,214	616,634	(178,591)
Total operating revenues	\$ 3,058,843	\$ 4,416,484	\$ 4,557,868

The following table summarizes the transaction price allocated to the Company's remaining performance obligations on all contracts with fixed consideration as of December 31, 2020. Amounts shown exclude contracts that qualified for the exception to the relative standalone selling price method as of December 31, 2020.

	2021	2022	2023	Total
	(Thousands)			
Natural gas sales	\$ 178,100	\$ 8,158	\$ 6,794	\$ 193,052

### 3. Derivative Instruments

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

The derivative commodity instruments used by the Company are primarily swap, collar and option agreements. These agreements 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 when executing its commodity hedging strategy. The Company typically enters into over the counter (OTC) derivative commodity instruments with financial institutions, and the creditworthiness of all counterparties is regularly monitored.

The Company does not designate any of its derivative instruments as cash flow hedges; therefore, all changes in fair value of the Company's derivative instruments are recognized in operating revenues in the Statements of Consolidated Operations. 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.

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

The Company's OTC derivative instruments generally 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 operating activities in the Statements of Consolidated Cash Flows.

With respect to the derivative commodity instruments held by the Company, the Company hedged portions of expected sales of production and portions of its basis exposure covering approximately 1,955 billion cubic feet (Bcf) of natural gas and 3,462 thousand barrels (Mbbbl) of NGLs as of December 31, 2020 and 1,644 Bcf of natural gas as of December 31, 2019. The open positions at both December 31, 2020 and 2019 had maturities extending through December 2024.

Certain of the Company's OTC derivative instrument contracts provide that, if the Company's credit rating assigned by Moody's Investors Service, Inc. (Moody's) or S&P Global Ratings (S&P) is below the agreed-upon credit rating threshold (typically, below investment grade), and if the associated derivative liability exceeds the agreed-upon dollar threshold for such credit rating, the counterparty to such contract can require the Company to deposit collateral. Similarly, if such counterparty's credit rating assigned by Moody's or S&P is below the agreed-upon credit rating threshold, and if the associated derivative liability exceeds the agreed-upon dollar threshold for such credit rating, the Company can require the counterparty to deposit collateral with the Company. Such collateral can be up to 100% of the derivative liability. Investment grade refers to the quality of a company's credit as assessed by one or more credit rating agencies. To be considered investment grade, a company must be rated "Baa3" or higher by Moody's, "BBB-" or higher by S&P and "BBB-" or higher by Fitch Rating Service (Fitch). Anything below these ratings is considered non-investment grade. As of December 31, 2020, the Company's senior notes were rated "Ba3" by Moody's and "BB" by S&P.

When the net fair value of any of the Company's OTC derivative instrument contracts represents a liability to the Company that is in excess of the agreed-upon dollar threshold for the Company's then-applicable credit rating, the counterparty has the right to require the Company to remit funds as a margin deposit in an amount equal to the portion of the derivative liability that is in excess of the dollar threshold amount. The Company records these deposits as a current asset in the Consolidated Balance Sheets. As of December 31, 2020, the aggregate fair value of all OTC derivative instruments with credit rating risk-related contingent features that were in a net liability position was \$137.7 million, for which the Company deposited and recorded \$21.1 million as a current asset. As of December 31, 2019, there were no such deposits recorded in the Consolidated Balance Sheet.

When the net fair value of any of the Company's OTC derivative instrument contracts represents an asset to the Company that is in excess of the agreed-upon dollar threshold for the counterparty's then-applicable credit rating, the Company has the right to require the counterparty to remit funds as a margin deposit in an amount equal to the portion of the derivative asset that is in excess of the dollar threshold amount. The Company records these deposits as a current liability in the Consolidated Balance Sheets. As of December 31, 2020 and 2019, there were no such deposits recorded in the Consolidated Balance Sheets.

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 is required to make such deposits based on an established initial margin requirement and 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. When the fair value of such contracts is in a net asset position, the broker may remit funds to the Company. The Company records these deposits as a current liability in the Consolidated Balance Sheets. The initial margin requirements are established by the exchanges based on the price, volatility and the time to expiration of the contract. The margin requirements are subject to change at the exchanges' discretion. As of December 31, 2020 and 2019, the Company recorded \$61.5 million and \$12.6 million, respectively, of such deposits as a current asset in the Consolidated Balance Sheets.

Refer to Note 5 for a discussion of the derivative liability recorded in connection with the Equitrans Share Exchange (defined in Note 5).

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 summarizes the impact of netting agreements and margin deposits on gross derivative assets and liabilities.

	Gross derivative instruments recorded in the Consolidated Balance Sheet	Derivative instruments subject to master netting agreements	Margin requirements with counterparties	Net derivative instruments
December 31, 2020	(Thousands)			
Asset derivative instruments at fair value	\$ 527,073	\$ (328,809)	\$ —	\$ 198,264
Liability derivative instruments at fair value	600,877	(328,809)	(82,552)	189,516
December 31, 2019				
Asset derivative instruments at fair value	\$ 812,664	\$ (226,116)	\$ —	\$ 586,548
Liability derivative instruments at fair value	312,696	(226,116)	(12,606)	73,974

The Company has not executed any interest rate swaps since 2011. As of December 31, 2019, amounts related to historical interest rate swaps that had been previously recorded in accumulated OCI were fully reclassified into interest expense. See Note 12.

#### 4. Fair Value Measurements

The Company records its financial instruments, which are principally derivative instruments, at fair value in the Consolidated Balance Sheets. The Company estimates the fair value of its financial instruments using quoted market prices when available. If quoted market prices are not available, the fair value is based on models that use market-based parameters, including forward curves, discount rates, volatilities and nonperformance risk, as inputs. 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 on a risk-free instrument.

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 that use Level 2 inputs primarily include the Company's swap, collar and option agreements.

Exchange traded commodity swaps have Level 1 inputs. The fair value of the commodity swaps with Level 2 inputs 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 used by the option pricing models include NYMEX forward curves, natural gas volatilities and LIBOR-based discount rates.

The table below summarizes assets and liabilities measured at fair value on a recurring basis.

	Gross derivative instruments recorded in the Consolidated Balance Sheets	Fair value measurements at reporting date using:		
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2020		(Thousands)		
Asset derivative instruments at fair value	\$ 527,073	\$ 70,603	\$ 456,470	\$ —
Liability derivative instruments at fair value	600,877	93,361	507,516	—
December 31, 2019				
Asset derivative instruments at fair value	\$ 812,664	\$ 95,041	\$ 717,623	\$ —
Liability derivative instruments at fair value	312,696	71,107	241,589	—

The carrying values of cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term maturities. The carrying value of the Company's investment in Equitrans Midstream approximates fair value as Equitrans Midstream is a publicly traded company. The carrying values of borrowings on the Company's credit facility and Term Loan Facility (which was fully repaid in the second quarter of 2020) approximate fair value as the interest rates are based on prevailing market rates. The Company considered all of these fair values to be Level 1 fair value measurements.

The Company has an immaterial investment in a fund that invests in companies developing technology and operating solutions for exploration and production companies. The Company recognized a cumulative effect of accounting change related to this investment in the first quarter of 2018. The investment is valued using, as a practical expedient, the net asset value provided in the financial statements received from fund managers and is recorded in other assets in the Consolidated Balance Sheets.

The Company estimates the fair value of its senior notes using established fair value methodology. Because not all of the Company's senior notes are actively traded, their fair value is a Level 2 fair value measurement. As of December 31, 2020 and 2019, the Company's senior notes had a fair value of approximately \$5.2 billion and \$3.9 billion, respectively, and a carrying value of approximately \$4.5 billion and \$3.9 billion, respectively, inclusive of any current portion. The fair value of the Company's note payable to EQM Midstream Partners, LP (EQM) is estimated using an income approach model with a market-based discount rate and is a Level 3 fair value measurement. As of December 31, 2020 and 2019, the Company's note payable to EQM had a fair value of approximately \$130 million and \$128 million, respectively, and a carrying value of approximately \$105 million and \$110 million, respectively, inclusive of any current portion. See Note 10 for further discussion of the Company's debt.

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, and impairments thereof, of proved and unproved oil and gas properties and other long-lived assets, see Note 1. For a discussion of other fair value measurements, see Note 5 for the Equitrans Share Exchange, Note 6 for the Chevron Acquisition and Asset Exchange Transactions (each defined in Note 6) and Note 7 for divestitures.

## 5. The Equitrans Share Exchange

On February 26, 2020, the Company entered into two share purchase agreements (the Share Purchase Agreements) with Equitrans Midstream, pursuant to which, among other things, the Company sold to Equitrans Midstream a total of 25,299,752 shares, or 50% of its ownership, of Equitrans Midstream's common stock in exchange for approximately \$52 million in cash and rate relief under certain of the Company's gathering contracts with EQM, an affiliate of Equitrans Midstream (the Equitrans Share Exchange). The transactions contemplated by the Share Purchase Agreements closed on March 5, 2020 (the Share Purchase Closing Date). The rate relief was effected through the execution of the Consolidated GGA (defined herein).

On February 26, 2020, the Company entered into a gas gathering and compression agreement (the Consolidated GGA) with an affiliate of EQM, pursuant to which, among other things, EQM agreed to provide to the Company gas gathering services in the

Marcellus and Utica Shales of Pennsylvania and West Virginia, and the Company committed to an initial annual minimum volume commitment of 3.0 Bcf per day and an acreage dedication in Pennsylvania and West Virginia. The Consolidated GGA is effective through December 31, 2035 and will renew annually thereafter unless terminated by the Company or EQM. The Consolidated GGA provides for additional cash bonus payments (the Henry Hub Cash Bonus) payable by the Company to EQM during the period beginning on the first day of the quarter in which the Mountain Valley Pipeline is placed in service and ending on the earlier of 36 months thereafter or December 31, 2024. Such payments are conditioned upon the quarterly average of the NYMEX Henry Hub natural gas settlement price exceeding certain price thresholds. In addition, the Consolidated GGA provides a cash payment option that grants the Company the right to receive payments from EQM in the event that the Mountain Valley Pipeline in-service date has not occurred prior to January 1, 2022.

On the Share Purchase Closing Date, the Company recorded in the Consolidated Balance Sheet a contract asset representing the estimated fair value of the rate relief provided by the Consolidated GGA of \$410 million, a derivative liability related to the Henry Hub Cash Bonus of approximately \$117 million and a decrease in the Company's investment in Equitrans Midstream of approximately \$158 million. The resulting gain of approximately \$187 million was recorded in the Statement of Consolidated Operations. Beginning with the Mountain Valley Pipeline in-service date, the Company expects to recognize amortization of the contract asset over a period of approximately four years in a manner consistent with the expected timing of the Company's realization of the economic benefits of the rate relief provided by the Consolidated GGA. As of December 31, 2020, the derivative liability related to the Henry Hub Cash Bonus was approximately \$107 million.

The fair value of the contract asset was based on significant inputs that are not observable in the market and, as such, is a Level 3 fair value measurement. Key assumptions used in the fair value calculation included an estimated production volume forecast, a market-based discount rate and a probability-weighted estimate of the in-service date of the Mountain Valley Pipeline. The fair value of the derivative liability related to the Henry Hub Cash Bonus was based on significant inputs that were interpolated from observable market data and, as such, is a Level 2 fair value measurement. See Note 4 for a description of the fair value hierarchy.

## **6. Acquisition and Exchange Transactions**

***Chevron Acquisition.*** In the fourth quarter of 2020, the Company acquired upstream assets and an investment in midstream gathering assets located in the Appalachian Basin from Chevron U.S.A. Inc. (Chevron) for an aggregate purchase price of \$735 million, subject to certain purchase price adjustments (the Chevron Acquisition). The transaction closed on November 30, 2020 and had an effective date of July 1, 2020.

The Chevron Acquisition included approximately 335,000 net Marcellus acres, approximately 400,000 net Utica acres, approximately 550 gross wells, which are producing approximately 450 net MMcf per day, and approximately 100 work-in-process wells at various stages in the development cycle. The Chevron Acquisition also included a 31% investment in the Laurel Mountain Midstream (LMM) gathering assets, which are operated by The Williams Companies, Inc., and two water systems that provide both fresh and produced water handling capabilities.

The Company does not have the power to direct the activities that most significantly impact LMM's economic performance; therefore, the Company is not the primary beneficiary and accounts for its investment in LMM as an equity method investment. The Company's pro-rata share of earnings in LMM is recorded as equity income which is included in dividend and other income on the Statements of Consolidated Operations.

The Chevron Acquisition was accounted for as a business combination, using the acquisition method. The following table summarizes the preliminary purchase price and the preliminary estimated fair values of assets acquired and liabilities assumed as of November 30, 2020. Certain data necessary to complete the purchase price allocation is not yet available, including, but not limited to, a final title defect analysis and final appraisals of assets acquired and liabilities assumed. The Company expects to complete the purchase price allocation during the second quarter of 2021, at which time the value of the assets acquired and liabilities assumed will be revised, if necessary.

	<b>Preliminary Purchase Price Allocation</b>	
	<b>(Thousands)</b>	
Cash consideration (a)	\$	691,942
Fair value of liabilities assumed:		
Accounts payable	\$	3,347
Other current liabilities		16,566
Deferred tax liability		939
Other liabilities and credits (b)		109,876
Amount attributable to liabilities assumed	\$	130,728
Fair value of assets acquired:		
Other current assets	\$	5,609
Net property, plant and equipment		720,315
Other assets		96,746
Amount attributable to assets acquired	\$	822,670

- (a) The difference between cash consideration and the aggregate purchase price of \$735 million represents the results of operating activities between the effective date of July 1, 2020 and the closing date of November 30, 2020 as well as amounts related to customary post-closing matters.
- (b) Other liabilities and credits included liabilities due to minimum volume commitment (MVC) contracts as well as liabilities for asset retirement obligations and environmental obligations.

The fair values of the acquired natural gas and oil properties were measured using discounted cash flow valuation techniques based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include future commodity prices, projections of estimated quantities of reserves, estimated future rates of production, projected reserve recovery factors, timing and amount of future development and operating costs and a weighted average cost of capital. The fair value of the undeveloped properties were measured using the guideline transaction method based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include future development plans from a market participant perspective and value per undeveloped acre.

The fair value of the acquired investment in LMM, which is included in other assets on the Consolidated Balance Sheet, was primarily measured using discounted cash flow valuation techniques. A majority of the inputs are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include projected revenues, expenses and capital expenditures.

The fair value of the acquired MVC liabilities were measured using expected throughput and annual MVCs per associated contract calculated on a discounted basis. A majority of the inputs are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include estimated future volumes and market participant cost of debt.

**2020 Asset Exchange Transactions.** During 2020, the Company closed on various acreage trade agreements (collectively, the 2020 Asset Exchange Transactions), pursuant to which the Company exchanged approximately 24,400 aggregate net revenue interest acres across Greene, Allegheny, Armstrong, Westmoreland and Washington Counties, Pennsylvania; Wetzel and Marshall Counties, West Virginia; and Belmont County, Ohio for approximately 19,400 aggregate net revenue interest acres across Greene and Washington Counties, Pennsylvania; Marshall, Wetzel and Marion Counties, West Virginia; and Belmont County, Ohio. As a result of the 2020 Asset Exchange Transactions, the Company recognized a net loss of \$61.6 million in impairment/loss on sale/exchange of long-lived assets in the Statement of Consolidated Operations for the year ended December 31, 2020.

**2019 Asset Exchange Transaction.** During the third quarter of 2019, the Company closed on an acreage trade agreement and purchase and sale agreement with a third party (the 2019 Asset Exchange Transaction), pursuant to which the Company exchanged approximately 16,000 net revenue interest acres primarily in Wetzel and Marion Counties, West Virginia. Under the terms of the purchase and sale agreement, the Company assigned to the third party a gas gathering agreement that covers a portion of Tyler County, West Virginia and provides a firm gathering commitment, and the Company was released from its remaining obligations under that gas gathering agreement. As consideration for the third party's assumption of the Tyler County gas gathering agreement, the Company agreed to reimburse the third party for certain firm gathering costs under the gas

gathering agreement through December 2022 and assign the third party an additional approximately 3,000 net revenue interest acres in Tyler and Wetzel Counties, West Virginia.

As a result of the 2019 Asset Exchange Transaction, the Company recognized a net loss of \$13.9 million in impairment/loss on sale/exchange of long-lived assets in the Statement of Consolidated Operations for the year ended December 31, 2019. As of December 31, 2020 and 2019, the liability for the reimbursement of those certain firm gathering costs was \$25.8 million and \$36.8 million, respectively, and was recorded in other current and noncurrent liabilities in the Consolidated Balance Sheets.

The fair value of leases acquired and, for the 2019 Asset Exchange Transaction, the fair value of the liability for the reimbursement of certain firm gathering costs were based on inputs that are not observable in the market and, as such, are a Level 3 fair value measurement. See Note 4 for a description of the fair value hierarchy. Key assumptions used in the fair value calculations included market-based prices for comparable acreage and the net present value of expected payments due for reimbursement.

## **7. Divestitures**

*2020 Divestitures.* On May 11, 2020, the Company closed a transaction to sell certain non-strategic assets located in Pennsylvania and West Virginia (the 2020 Divestiture) for an aggregate purchase price of approximately \$125 million in cash, subject to customary purchase price adjustments and the Contingent Consideration defined and discussed below. The Pennsylvania assets sold included 80 Marcellus wells and approximately 33 miles of gathering lines; the West Virginia assets sold included 809 conventional wells and approximately 154 miles of gathering lines. In addition, the 2020 Divestiture relieved the Company of approximately \$49 million in asset retirement obligations and other liabilities associated with the sold assets. Proceeds from the sale were used to pay down the Company's Term Loan Facility. See Note 10.

The purchase and sale agreement for the 2020 Divestiture provides for additional cash bonus payments (the Contingent Consideration) payable to the Company of up to \$20 million. Such Contingent Consideration is conditioned upon the three-month average of the NYMEX Henry Hub natural gas settlement price relative to stated floor and target price thresholds beginning on August 31, 2020 and ending on November 30, 2022. The Contingent Consideration represents an embedded derivative that is recorded at fair value in the Consolidated Balance Sheets. The Contingent Consideration had no fair value as of May 11, 2020 and a fair value of \$1.9 million as of December 31, 2020. During the year ended December 31, 2020, the Company received contingent consideration cash of \$0.9 million. Changes in fair value are recorded in impairment/loss on sale/exchange of long-lived assets in the Statements of Consolidated Operations. The fair value of the Contingent Consideration is based on significant inputs that are interpolated from observable market data and, as such, is a Level 2 fair value measurement. See Note 4 for a description of the fair value hierarchy.

As a result of the 2020 Divestiture, the Company recognized a net loss of \$39.1 million, including the impact of the change in fair value of the Contingent Consideration, in impairment/loss on sale/exchange of long-lived assets in the Statement of Consolidated Operations during the year ended December 31, 2020.

*2018 Divestiture.* In 2018, the Company sold its non-core production and related midstream assets located in the Huron play and Permian Basin (the 2018 Divestitures). For the year ended December 31, 2018, as a result of the 2018 Divestitures, the Company recorded an impairment/loss on sale of long-lived assets of \$2.4 billion due to the carrying value of the properties and related pipeline assets exceeding the amounts received for the 2018 Divestitures.

The fair value of the impaired assets was based on significant inputs that are not observable in the market and, as such, are considered to be Level 3 fair value measurements. See Note 4 for a description of the fair value hierarchy and Note 1 for the Company's policy on impairment of proved and unproved properties. Key assumptions included in the calculation of the fair value of the impaired assets included the following: reserves, including risk adjustments for probable and possible reserves; future commodity prices; to the extent available, market-based indicators of fair value including estimated proceeds that could be realized upon a potential disposition; production rates based on the Company's experience with similar properties it operates; estimated future operating and development costs; and a market-based weighted average cost of capital.

In connection with the closing of the 2018 Divestitures, the Company recorded a loss of \$259.3 million during the third quarter of 2018 related to certain capacity contracts that the Company no longer has existing production to satisfy and does not plan to use in the future. The loss was recorded in impairment/loss on sale/exchange of long-lived assets in the Statement of Consolidated Operations. The fair value of the loss for the initial measurement was based on significant inputs that are 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 of potential future economic benefit from the contracts. See Note 4 for a description of the fair value hierarchy.

## 8. Separation and Distribution and Discontinued Operations

On November 12, 2018, the Company completed the separation of its midstream business, which was composed of the separately operated natural gas gathering, transmission and storage and water services businesses of the Company, from its upstream business, which is composed of the natural gas, NGLs and oil development, production and sales and commercial operations of the Company (the Separation). The Separation was effected by the transfer of the midstream business from the Company to Equitrans Midstream and the distribution of 80.1% of the outstanding shares of Equitrans Midstream's common stock to the Company's shareholders (the Distribution). The Company's shareholders received 0.80 shares of Equitrans Midstream's common stock for every one share of EQT common stock held as the close of business on November 1, 2018. The Company retained 19.9% of the outstanding shares of Equitrans Midstream's common stock. See Note 1 for a discussion of the Company's accounting for the investment in Equitrans Midstream and Note 5 for a discussion of the Company's sale of a portion of its shares of Equitrans Midstream's common stock in 2020.

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.

In the ordinary course of business, the Company engages in transactions with Equitrans Midstream 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 comprised the Company's former EQM Gathering, EQM Transmission and EQM Water segments. For all periods prior to the Separation and Distribution, the results of operations of Equitrans Midstream are reflected as discontinued operations. The Statement of Consolidated Operations for the year ended December 31, 2018 has been recast to reflect discontinued operations presentation and include certain transportation and processing expenses in continuing operations that had previously been eliminated in consolidation. Cash flows related to Equitrans Midstream are included in the Statement of Consolidated Cash Flows for the period prior to the Separation and Distribution. The results of operations of Equitrans Midstream are summarized below. The Company allocated transaction costs associated with the Separation and Distribution and a portion of transaction costs associated with the 2017 acquisition of Rice Energy Inc. (the Rice Merger) to discontinued operations.

	<b>January 1, 2018 to November 12, 2018</b>
	<b>(Thousands)</b>
Operating revenues	\$ 388,854
Transportation and processing	(803,858)
Operation and maintenance	99,671
Selling, general and administrative	62,702
Depreciation	160,701
Impairment of goodwill (a)	267,878
Transaction costs	93,062
Amortization of intangible assets	36,007
Other income	51,014
Interest expense	88,300
Income from discontinued operations before income taxes	435,405
Income tax expense	61,643
Income from discontinued operations after income taxes	373,762
Less: Net income from discontinued operations attributable to noncontrolling interests	237,410
Net income from discontinued operations	\$ 136,352

- (a) Following the third quarter of 2018, and prior to the Separation and Distribution, indicators of goodwill impairment were identified in the form of announced production curtailments, which could reduce the volumetric-based fee revenues of two reporting units to which the Company's goodwill was recorded. The two reporting units, Rice Retained Midstream and RMP PA Gas Gathering, were allocated to discontinued operations as a result of the Separation and Distribution. Both of these reporting units earned 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 was used. The discounted cash flow method income approach applies significant inputs that are 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 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, but 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 in the Consolidated Balance Sheet and allocated to discontinued operations.

The following table presents cash flows from or used in discontinued operations related to Equitrans Midstream that are included, and not separately stated, in the Statement of Consolidated Cash Flows for the year ended December 31, 2018.

	<b>January 1, 2018 to November 12, 2018</b>
	<b>(Thousands)</b>
<b>Cash flows from operating activities:</b>	
Deferred income tax benefit	\$ (373,405)
Depreciation	160,701
Amortization of intangibles	36,007
Impairment of goodwill	267,878
Other income	(51,450)
Share-based compensation expense	1,841
<b>Cash flows from investing activities:</b>	
Capital expenditures	\$ (732,727)
Capital contributions to Mountain Valley Pipeline, LLC (a)	(820,943)
<b>Cash flows from financing activities:</b>	
Proceeds from issuance of debt	\$ 2,500,000
Proceeds in borrowings on credit facility	3,378,500
Repayment of borrowings on credit facility	(3,219,500)
Debt issuance costs	(40,966)
Distributions to noncontrolling interests	(380,651)
Acquisition of 25% of Strike Force Midstream LLC	(175,000)

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

## 9. Income Taxes

The following table summarizes income tax (benefit) expense.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Current:			
Federal	\$ (132,625)	\$ (106,487)	\$ (513,293)
State	(10,393)	5,774	(46,218)
Subtotal	(143,018)	(100,713)	(559,511)
Deferred:			
Federal	(131,355)	(213,397)	20,496
State	(24,485)	(61,666)	(157,496)
Subtotal	(155,840)	(275,063)	(137,000)
Total income tax benefit	\$ (298,858)	\$ (375,776)	\$ (696,511)

For the year ended December 31, 2020, the current federal and state income tax benefit consisted primarily of refunds of \$117 million, including interest, related to the Company's alternative minimum tax (AMT) credit carryforward, the Tax Cuts and Jobs Act of 2017 (the Tax Cuts and Jobs Act) and the acceleration of the receipt of such refunds with the Coronavirus Aid, Relief and Economic Security Act (CARES Act). The remainder of the tax benefit of \$26 million, including interest, is related to federal and state audits that were settled in 2020. For the year ended December 31, 2019, the current U.S. federal income tax benefit consisted primarily of expected refunds of \$120 million related to the Company's AMT credit carryforward and the Tax Cuts and Jobs Act. For the year ended December 31, 2018, the current U.S. federal income tax benefit consisted primarily of an expected refund of \$141 million related to the Company's AMT credit carryforward, partly offset by \$16 million of current state tax expense. The remaining current tax benefit of \$435 million for the year ended December 31, 2018, 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. The Tax Cuts and Jobs Act also preserved deductibility of intangible drilling costs (IDCs) for U.S. 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 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 provided that existing AMT credit carryforwards can be used to offset current federal taxes owed with 50% of any remaining balance being refunded in tax years 2018 through 2020. With the passing of the CARES Act, the Company was able to accelerate these refunds to 2020. As a result of an IRS announcement in January 2019 that reversed 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 reversed the related valuation allowance of \$13 million in the first quarter of 2019.

The Tax Cuts and Jobs Act limited the deductibility of interest expense, and, as a result, the Company recorded a valuation allowance in 2019 for a portion of the interest expense limit imposed for separate company state income tax purposes. During 2020, final regulations were issued that provided clarity on several issues that were beneficial to the Company including (i) the exclusion of commitment fees and debt issuance costs from the definition of interest and (ii) the inclusion of the adding back depreciation, depletion and amortization associated with cost of goods sold to arrive at adjusted taxable income. These changes eliminated the interest expense limitation for the Company and the related valuation allowance was reversed in 2020.

The Company has federal net operating loss (NOLs) carryforwards related to the Rice Merger and NOLs generated in 2017 in excess of amounts carried back to prior years. The Company also has NOLs acquired in the Company's 2016 acquisition of Trans Energy, Inc., of which a nominal amount is available for use annually over the next 20 years. The Tax Cuts and Jobs Act limited the utilization of NOLs generated after December 31, 2017 that have been carried forward into future years to 80% of taxable income and eliminated 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. As a result of the CARES Act, NOLs generated in 2018, 2019 and 2020 can be carried back five years and are allowed to fully offset taxable income ignoring the 80% limitation if utilized prior to 2021.

Income tax benefit from continuing operations differed from amounts computed at the federal statutory rate of 21% on pre-tax income for reasons summarized below.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Tax at statutory rate	\$ (265,867)	\$ (335,469)	\$ (646,261)
State income taxes	(75,035)	(119,659)	(251,780)
Valuation allowance	106,548	81,522	88,785
Tax settlements	(33,384)	—	—
Federal and state tax credits	(11,628)	(7,908)	(2,400)
Goodwill impairment	—	—	111,470
Other	(19,492)	5,738	3,675
Income tax benefit	<u>\$ (298,858)</u>	<u>\$ (375,776)</u>	<u>\$ (696,511)</u>
Effective tax rate	<u>23.6 %</u>	<u>23.5 %</u>	<u>22.6 %</u>

The Company's effective tax rate for the year ended December 31, 2020 was higher compared to the U.S. federal statutory rate due primarily to state income taxes and federal and state income tax settlements, partly offset by valuation allowances that limit certain federal and state tax benefits. The Company's effective tax rate for the year ended December 31, 2019 was higher compared to the U.S. federal statutory rate due primarily to state income taxes and the release of the valuation allowance related to AMT sequestration, partly offset by valuation allowances that limit certain state tax benefits. The Company's effective tax rate for the year ended December 31, 2018 was higher compared to the U.S. federal statutory rate due primarily to 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 goodwill allocated to continuing operations that had been impaired in 2018.

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, 2020, 2019 and 2018, positive evidence considered included the 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 resulted in the conclusion that valuation allowances for certain NOLs were warranted as it was more likely than not that the Company would not use them prior to expiration. Uncertainties such as future commodity prices can affect the Company's calculations and its ability to use these NOLs prior to expiration. Further, because of the Tax Cuts and Jobs Act, the Company recorded a write-off of deferred tax assets related to certain executive incentive-based awards to be paid in a future year that will not be deductible.

During 2020 and 2019, the Company recorded a partial valuation allowance against a deferred tax asset related to the unrealized loss recorded on its investment in Equitrans Midstream that it does not believe it will be able to utilize due to limitations imposed on capital losses. The Company has capital loss carryback capacity and provided a valuation allowance on the portion in excess of the carryback. Management will continue to assess the potential for realizing deferred tax assets based on 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.

	2020	2019	2018
	(Thousands)		
Balance at January 1	\$ 259,588	\$ 315,279	\$ 301,558
Additions for tax positions taken in current year	5,470	19,431	8,459
Additions for tax positions taken in prior years	7,250	8,929	14,396
Reductions for tax positions taken in prior years	(38,859)	(84,051)	(9,134)
Reductions for tax positions settled with tax authorities	(58,236)	—	—
Balance at December 31	\$ 175,213	\$ 259,588	\$ 315,279

Included in the balances above are unrecognized tax benefits of \$91.0 million, \$150.9 million and \$124.6 million that, if recognized, would affect the effective tax rates as of December 31, 2020, 2019 and 2018, respectively. Also included in the balances above are uncertain tax positions of \$90.3 million, \$113.7 million, and \$88.2 million for the years ended December 31, 2020, 2019 and 2018, respectively, that were recorded in the Consolidated Balance Sheets as a reduction of the related deferred tax asset for general business credit carryforwards and NOLs. During 2020, the Company adjusted its tax reserves as a result of settling its 2010 – 2012 amended return refund claim with the IRS by (i) reducing the uncertain tax positions and increasing the amount of the deferred tax asset for AMT credits by \$14.9 million, (ii) reducing the uncertain tax position offset to the deferred tax asset for Research and Experimentation credits by \$35.3 million and (iii) writing down the deferred tax asset by \$22.6 million to the settlement amount. In addition, in 2020, the Company settled a dispute related to its 2013 Pennsylvania returns and reduced the uncertain tax positions by \$46.9 million and agreed to remit \$33.5 million to the Commonwealth of Pennsylvania. During 2019, the Company released \$84.0 million of reserves and reinstated the related deferred tax asset for AMT due to settlement of the 2013 amended return refund claim with the IRS.

Included in the balances above are \$0.0 million, \$0.7 million and \$0.7 million, as of December 31, 2020, 2019 and 2018, respectively, for tax positions for which the ultimate deductibility is highly certain but 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 (income) expense of approximately \$(3.8) million, \$3.3 million and \$3.4 million for the years ended December 31, 2020, 2019 and 2018, respectively. Interest and penalties of \$11.4 million and \$15.2 million were included in the Consolidated Balance Sheets at December 31, 2020 and 2019, respectively.

As of December 31, 2020, 2019 and 2018, the Company believed that, as a result of potential settlements with, or legal or administrative guidance by, relevant taxing authorities or the lapse of applicable statutes of limitation, it is reasonably possible that a decrease of \$125.9 million, \$80.2 million and \$33.3 million, respectively, in unrecognized tax benefits related to federal tax positions may be necessary within twelve months.

The Company's consolidated U.S. federal income tax liability has been settled with the IRS through 2013. The Company is also the subject of various state income tax examinations. As of December 31, 2020, with few exceptions, the Company is no longer subject to state examinations by tax authorities for years before 2015.

There were no material changes to the Company's methodology for accounting for unrecognized tax benefits during 2020.

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

	December 31,	
	2020	2019
	(Thousands)	
<b>Deferred income taxes:</b>		
Total deferred income tax assets	\$ (610,821)	\$ (643,227)
Total deferred income tax liabilities	1,982,788	2,129,041
Total net deferred income tax liabilities	1,371,967	1,485,814
<b>Total deferred income tax liabilities (assets):</b>		
Drilling and development costs expensed for income tax reporting	918,120	1,100,061
Tax depreciation in excess of book depreciation	1,027,179	974,520
Investment in Equitrans Midstream	(94,689)	(109,883)
Incentive compensation and deferred compensation plans	(22,419)	(16,923)
NOL carryforwards	(789,544)	(635,446)
Alternative minimum tax credit carryforward	(81,237)	(190,992)
Federal tax credits	(79,846)	(59,854)
State capital loss carryforward	(28,317)	—
Unrealized (losses) gains	(43,475)	54,460
Interest disallowance limitation	(160)	(46,776)
Convertible debt	37,489	—
Other	(1,126)	(6,797)
Total excluding valuation allowances	841,975	1,062,370
Valuation allowances	529,992	423,444
Total net deferred income tax liabilities	\$ 1,371,967	\$ 1,485,814

During 2020, net deferred tax liability decreased by \$113.8 million compared to 2019 due primarily to book impairments, which are included in drilling and development costs expensed for income tax reporting but are not currently deductible for tax purposes, and the Company's investment in Equitrans Midstream, partly offset by increased tax depreciation in excess of book depreciation.

As of December 31, 2020, the Company had a deferred tax asset of \$233.2 million, net of valuation allowances of \$22.8 million, related to tax benefits from federal NOL carryforwards generated prior to 2018 and expiring between 2035 to 2037. Federal NOLs generated in 2018 and thereafter are represented by a deferred tax asset of \$75.6 million and will carryforward indefinitely but will be limited to offset 80% of taxable income in each year. As of December 31, 2020, the Company had a deferred tax asset of \$480.8 million, net of valuation allowances of \$387.7 million, related to tax benefits from state NOL carryforwards with expiration dates ranging from 2021 to 2040. Due to a decrease in state apportionment rates and impairment of assets, the Company will have less realizable NOLs in future years on a separate company basis and, as such, in 2020 recorded a valuation allowance on its property, plant and equipment state deferred tax asset of \$0.6 million. In 2020, the Company incurred an unrealized loss on its investment in Equitrans Midstream. This investment is a capital asset for tax purposes and capital losses can only be utilized to offset a capital gain and are limited to being carried back three years and forward five years for potential utilization. Due to these limitations, the Company also recorded a valuation allowance on the deferred tax asset for its retained equity stake of Equitrans Midstream of \$62.4 million for separate company state income tax reporting purposes and \$56.4 million for federal.

As of December 31, 2019, the Company had a deferred tax asset of \$218.8 million, net of valuation allowances of \$22.8 million, related to tax benefits from federal NOL carryforwards expiring in 2037. Federal NOLs generated in 2018 and forward will carryforward indefinitely but will be limited to offset 80% of taxable income in each year. As of December 31, 2019, the Company had a deferred tax asset of \$416.7 million, net of valuation allowances of \$324.1 million, related to tax benefits from state NOL carryforwards with various expiration dates ranging from 2020 to 2039. Due to a decrease in state apportionment rates and impairment of assets, the Company will have less realizable NOLs in future years and, as such, had to record a valuation allowance on its property, plant and equipment state deferred tax asset of \$4.5 million in 2019. Additionally, for separate company state income tax reporting purposes, the Tax Cuts and Jobs Act interest deduction limitation resulted in a valuation allowance of \$21.3 million recorded in 2019. In 2019, the Company incurred an unrealized loss on its investment in

Equitrans Midstream. This investment is a capital asset for tax purposes and capital losses can only be utilized to offset a capital gain and are limited to being carried back three years and forward five years for potential utilization. Due to these limitations, the Company also recorded a valuation allowance on the deferred tax asset recorded for its retained equity stake of Equitrans Midstream of \$42.4 million for separate company state income tax reporting purposes and \$8.3 million for federal.

For the year ended December 31, 2019, the Company recorded a \$90.9 million adjustment to retained earnings and additional paid-in-capital related to the Separation and Distribution. The Separation and Distribution resulted in the recognition of a tax gain related to a pre-Separation transaction. Recognition occurred as a result of Equitrans Midstream exiting the Company's consolidated federal filing group. The gain amount reported in the tax return was different than the amount estimated in the 2018 financial statements; therefore, the Company recorded a return-to-provision adjustment in 2019. This adjustment impacts the amount of deferred taxes transferred to Equitrans Midstream as of the Separation and Distribution date of November 12, 2018.

## 10. Debt

	December 31, 2020			December 31, 2019		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
	(Thousands)					
Credit Facility expires July 2022	\$ 300,000	\$ 300,000	\$ 300,000	\$ 294,000	\$ 294,000	\$ 294,000
Term Loan Facility due May 31, 2021	—	—	—	1,000,000	999,353	999,353
Senior notes:						
Floating rate notes due October 1, 2020	—	—	—	500,000	499,238	500,290
2.50% notes due October 1, 2020	—	—	—	500,000	499,228	500,950
8.81% to 9.00% series A notes due 2020 – 2021	24,000	24,000	25,232	35,200	35,200	37,380
4.875% notes due November 15, 2021	125,118	124,943	128,231	750,000	747,571	774,173
3.00% notes due October 1, 2022	568,823	566,689	578,055	750,000	745,579	737,025
7.42% series B notes due 2023	10,000	10,000	10,038	10,000	10,000	10,788
7.875% notes due February 1, 2025 (c)	1,000,000	992,905	1,146,250	—	—	—
1.75% convertible notes due May 1, 2026	500,000	359,635	587,385	—	—	—
7.75% debentures due July 15, 2026	115,000	112,224	137,025	115,000	111,727	129,466
3.90% notes due October 1, 2027	1,250,000	1,242,182	1,249,400	1,250,000	1,241,024	1,167,763
5.00% notes due January 15, 2029	350,000	344,106	371,469	—	—	—
8.750% notes due February 1, 2030 (c)	750,000	743,726	924,510	—	—	—
Note payable to EQM	105,056	105,056	130,464	110,059	110,059	128,241
Total debt	5,097,997	4,925,466	5,588,059	5,314,259	5,292,979	5,279,429
Less: Current portion of debt	154,336	154,161	159,943	16,204	16,204	17,436
Long-term debt	<u>\$ 4,943,661</u>	<u>\$ 4,771,305</u>	<u>\$ 5,428,116</u>	<u>\$ 5,298,055</u>	<u>\$ 5,276,775</u>	<u>\$ 5,261,993</u>

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

(b) The carrying value of borrowings under the Company's credit facility and Term Loan Facility approximate fair value as the interest rates are based on prevailing market rates; therefore, they are a Level 1 fair value measurement. For the note payable to EQM, fair value is measured using Level 3 inputs. For all other debt, fair value is measured using Level 2 inputs. See Note 4 for a description of the fair value hierarchy.

(c) See discussion below of the interest rate on these notes under "Adjustable Rate Notes."

As of December 31, 2020, aggregate maturities for the Company's senior notes were \$149 million in 2021, \$569 million in 2022, \$10 million in 2023, \$0 million in 2024, \$1,000 million in 2025 and \$2,965 million thereafter. 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.

**\$2.5 Billion Credit Facility.** The Company has a \$2.5 billion 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. The

Company may, on a one-time basis, request that the lenders' commitments be increased to an aggregate of up to \$3.0 billion, subject to certain terms and conditions. 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 20 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 credit ratings. Eurodollar rate loans bear interest at a Eurodollar rate plus a margin based on the Company's credit ratings. Based on the Company's senior notes credit rating as of December 31, 2020, the margin on base rate loans was 1.00% and the margin on Eurodollar rate loans was 2.00%.

The Company is not required to maintain compensating bank balances. The Company's debt issuer credit ratings, as determined by Moody's, S&P or 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'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 are the 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 which excludes the effects of accumulated OCI. As of December 31, 2020, the Company was in compliance with all debt provisions and covenants.

The Company had \$0.8 billion of letters of credit outstanding under its credit facility as of December 31, 2020 and no letters of credit outstanding under its credit facility as of December 31, 2019. For each of the years ended December 31, 2020, 2019 and 2018, the Company incurred commitment fees of approximately 28, 20 and 20 basis points, respectively, on the undrawn portion of its credit facility to maintain credit availability.

Under the Company's credit facility, for the years ended December 31, 2020, 2019 and 2018, the maximum amounts of outstanding borrowings were \$0.7 billion, \$1.1 billion and \$1.6 billion, respectively, the average daily balances were approximately \$148 million, \$340 million and \$854 million, respectively, and interest was incurred at weighted average annual interest rates of 2.3%, 3.8% and 3.4%, respectively.

*Term Loan Facility.* The Company had a \$1.0 billion unsecured term loan facility (the Term Loan Facility) that was scheduled to mature in May 2021. In 2019, the Company used the proceeds from borrowings of \$1.0 billion under the Term Loan Facility to repay \$700 million aggregate principal amount of 8.125% senior notes, repay outstanding borrowings under the Company's \$2.5 billion credit facility and pay accrued interest and fees and expenses related to the term loan agreement. Borrowings under the Term Loan Facility that are repaid may not be reborrowed.

The Company used proceeds from the offering of its Convertible Notes (see below), income tax refunds received during 2020 (see Note 9) and proceeds from the 2020 Divestiture (see Note 7) to fully repay its Term Loan Facility on June 30, 2020. Under the Company's Term Loan Facility, from January 1, 2020 through June 30, 2020, the average daily balance was approximately \$692 million and interest was incurred at a weighted average annual interest rate of 2.6%. For the period May 31, 2019 through December 31, 2019, the average daily balance was \$1.0 billion and interest was incurred at a weighted average annual interest rate of 3.1%.

*Adjustable Rate Notes.* On January 21, 2020, the Company issued \$1.0 billion aggregate principal amount of 6.125% senior notes due February 1, 2025 and \$750 million aggregate principal amount of 7.000% senior notes due February 1, 2030 (together, the Adjustable Rate Notes). The Company used the net proceeds from the Adjustable Rate Notes to repay \$500 million aggregate principal amount of the Company's floating rate notes, \$500 million aggregate principal amount of the Company's 2.50% senior notes, \$500 million aggregate principal amount of the Company's 4.875% senior notes and \$200 million of the Company's Term Loan Facility borrowings.

The covenants of the Adjustable Rate Notes are consistent with the Company's existing senior unsecured notes, with an additional interest rate adjustment provision that provides for adjustments to the interest rates on the Adjustable Rate Notes based on credit ratings assigned by Moody's, S&P and Fitch to the Company's senior notes. As a result of changes to the Company's senior notes credit rating, the interest rate on the 6.125% senior notes and the 7.000% senior notes was 7.875% and

8.750%, respectively, as of December 31, 2020. The adjusted interest rate under the Adjustable Rate Notes cannot exceed 2% of the original interest rate first set forth on the face of the Adjustable Rate Notes; however, if the Company's credit ratings improve, the interest rate under the Adjustable Rate Notes could be reduced to as low as the original interest rate set forth on the face of the Adjustable Rate Notes.

*Convertible Notes.* On April 28, 2020, the Company issued \$500 million aggregate principal amount of 1.75% convertible senior notes (the Convertible Notes) due May 1, 2026 unless earlier redeemed, repurchased or converted. The Convertible Notes were issued in a private offering to qualified institutional buyers pursuant to Rule 144A under the Securities Act of 1933, as amended. After deducting offering costs of \$16.9 million and Capped Call Transactions (defined and discussed below) costs of \$32.5 million, the net proceeds from the offering of \$450.6 million were used to repay \$450 million of the Company's Term Loan Facility borrowings as well as for general corporate purposes.

Holders of the Convertible Notes may convert their Convertible Notes, at their option, at any time prior to the close of business on January 30, 2026 under the following circumstances:

- during any quarter commencing after the quarter ended June 30, 2020 as long as the last reported price of EQT common stock for at least 20 trading days (consecutive or otherwise) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding quarter is greater than or equal to 130% of the conversion price on each such trading day;
- during the five-business-day period after any five-consecutive-trading-day period (the measurement period) in which the trading price per \$1,000 principal amount of the Convertible Notes for each trading day of the measurement period is less than 98% of the product of the last reported price of EQT common stock and the conversion rate for the Convertible Notes on each such trading day;
- if the Company calls any or all of the Convertible Notes for redemption, at any time prior to the close of business on the second scheduled trading day immediately preceding such redemption date; and
- upon the occurrence of certain corporate events set forth in the Convertible Notes indenture.

On or after February 1, 2026, holders of the Convertible Notes may convert their Convertible Notes, at their option, at any time until the close of business on the second scheduled trading date immediately preceding May 1, 2026.

Upon conversion of the Convertible Notes, the Company intends to use a combined settlement approach to satisfy its settlement obligation by paying or delivering to holders of the Convertible Notes cash equal to the principal amount of the obligation and EQT common stock for amounts that exceed the principal amount of the obligation.

The Company may not redeem the Convertible Notes prior to May 5, 2023. On or after May 5, 2023 and prior to February 1, 2026, the Company may redeem for cash all or any portion of the Convertible Notes, at its option, at a redemption price equal to 100% of the principal amount of the Convertible Notes to be redeemed plus accrued and unpaid interest up to the redemption date as long as the last reported price per share of EQT common stock has been at least 130% of the conversion price in effect for at least 20 trading days (consecutive or otherwise) during any 30-consecutive-trading-day period ending on the trading day immediately preceding the date on which the Company delivers notice of redemption. A sinking fund is not provided for the Convertible Notes.

The initial conversion rate for the Convertible Notes is 66.6667 shares of EQT common stock per \$1,000 principal amount of the Convertible Notes, which is equivalent to an initial conversion price of \$15.00 per share of EQT common stock. The initial conversion price represents a premium of 20% to the \$12.50 per share closing price of EQT common stock on April 23, 2020. The conversion rate is subject to adjustment under certain circumstances. In addition, following certain corporate events that occur prior to May 1, 2026 or if the Company delivers notice of redemption, the Company will, in certain circumstances, increase the conversion rate for a holder who elects to convert its Convertible Notes in connection with such corporate event or notice of redemption.

In connection with the Convertible Notes offering, the Company entered into privately negotiated capped call transactions (the Capped Call Transactions), the purpose of which is to reduce the potential dilution to EQT common stock upon conversion of the Convertible Notes and/or offset any cash payments the Company is required to make in excess of the principal amount of such obligation, with such reduction and offset subject to a cap. The Capped Call Transactions have an initial strike price of \$15.00 per share of EQT common stock and an initial capped price of \$18.75 per share of EQT common stock, each of which are subject to certain customary adjustments.

For accounting purposes, the Company separated the Convertible Notes into liability and equity components. The carrying amount of the liability component was calculated by measuring the fair value of similar debt instruments that do not have

associated convertible features. The carrying amount of the equity component, representing the conversion option, was determined by deducting the fair value of the liability component from the principal value of the Convertible Notes. The equity component is not remeasured as long as it continues to meet the condition for equity classification. The excess of the principal amount of the liability component over its carrying amount (the debt discount) will be amortized to interest expense over the term of the Convertible Notes, which is approximately 6 years, at an effective interest rate of 8.4%. At inception, the Company recorded the Convertible Notes at fair value of approximately \$358.1 million, a net deferred tax liability of \$41.0 million and an equity component of \$100.9 million.

Issuance costs were allocated to the liability and equity components of the Convertible Notes based on their relative fair values. Issuance costs attributable to the liability component of \$12.1 million were recorded as a reduction to the liability component of the Convertible Notes and will be amortized to interest expense over the term of the Convertible Notes at an effective interest rate of 8.4%. Issuance costs attributable to the equity component of \$4.8 million, representing the conversion option, were netted with the equity component.

The Capped Call Transactions are separate from the Convertible Notes. The Capped Call Transactions were recorded in shareholders' equity and were not accounted for as derivatives. The cost to purchase the Capped Call Transactions was recorded as a reduction to equity and will not be remeasured.

For the year ended December 31, 2020, the Convertible Notes had a net shareholders' equity impact of \$63.6 million, which consisted of the conversion option equity component of \$100.9 million less the Capped Call Transactions costs of \$32.5 million and issuance costs attributable to the equity component of \$4.8 million.

As of December 31, 2020, the net carrying amount of the Convertible Notes liability component consisted of principal of \$500 million less the unamortized debt discount of \$129.1 million and unamortized issuance costs of \$11.3 million. The table below summarizes the components of interest expense related to the Convertible Notes.

	<b>Year Ended December 31, 2020</b>	
	<b>(Thousands)</b>	
Contractual interest expense	\$	5,906
Amortization of debt discount		12,856
Amortization of issuance costs		853
<b>Total Convertible Notes interest expense</b>	<b>\$</b>	<b>19,615</b>

**5.00% Senior Notes.** On November 16, 2020, the Company issued \$350 million aggregate principal amount of 5.00% senior notes due January 15, 2029. After deducting offering costs of \$6.0 million, the net proceeds from the offering of \$344.0 million were used to fund a portion of the purchase price of the Chevron Acquisition described in Note 6. The covenants of the 5.00% senior notes are consistent with the Company's existing senior unsecured notes; provided, however, that the 5.00% senior notes include an additional offer to repurchase provision applicable upon the occurrence of certain change of control events specified in the related indenture.

**2020 Debt Repayments.** In February 2020, the Company fully redeemed its floating rate notes and 2.50% senior notes at a price of 100% and 100.446% (inclusive of a make whole premium), respectively, of each note's principal amount plus accrued but unpaid interest of \$1.2 million and \$4.2 million, respectively. This resulted in the payment of make whole call premiums of \$2.2 million related to the 2.50% senior notes.

Throughout 2020, the Company repurchased \$624.9 million aggregate principal amount of the Company's 4.875% senior notes at a total cost of \$647.3 million, inclusive of tender premiums of \$13.7 million and accrued but unpaid interest of \$8.7 million.

In November 2020, the Company repurchased \$181.2 million aggregate principal amount of the Company's 3.00% senior notes at a total cost of \$182.8 million, inclusive of a tender premium of \$0.9 million and accrued but unpaid interest of \$0.7 million.

**Note Payable to EQM.** EQM owns a preferred interest in EQT Energy Supply, LLC (EES), a subsidiary of the Company, that is accounted for as a note payable due to the terms of the operating agreement of EES. The fair value of the note payable to EQM is a Level 3 fair value measurement and is estimated using an income approach model using a market-based discount rate. Principal amounts due for the note payable to EQM are \$5.2 million in 2021, \$5.5 million in 2022, \$5.8 million in 2023, \$6.3 million in 2024, \$6.5 million in 2025 and \$75.8 million thereafter.

**Surety Bonds.** During the year ended December 31, 2020, the Company issued approximately \$93 million in surety bonds in response to its credit downgrades by Moody's, S&P and Fitch.

**Subsequent Events.** On February 1, 2021, the Company redeemed the remaining \$125.1 million aggregate principal amount of the Company's 4.875% senior notes at a total cost of \$130.7 million, inclusive of redemption premiums of \$4.3 million and accrued but unpaid interest of \$1.3 million.

## 11. Common Stock

As of December 31, 2020, the Company reserved 13.7 million shares of authorized and unissued EQT common stock for stock compensation plans and 40 million shares of authorized and unissued EQT common stock for settlement of the Convertible Notes.

In October 2020, the Company entered into an underwriting agreement under which the Company sold 20,000,000 shares of common stock at a price to the public of \$15.50 per share. In November 2020, the option to purchase 3,000,000 additional shares was exercised by the underwriters on the same terms. After deducting offering costs of \$15.6 million, the net proceeds of \$340.9 million were used to fund a portion of the purchase price of the Chevron Acquisition described in Note 6.

The Company made no share repurchases in 2020 or 2019. During 2018, the Company repurchased 10,646,382 shares of EQT common stock at an average price of \$50.62, which included \$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.

## 12. Changes in Accumulated OCI (Loss) by Component

The following table explains the changes in accumulated OCI (loss) by component.

	Natural gas cash flow hedges, net of tax	Interest rate cash flow hedges, net of tax	Other postretirement benefits liability adjustment, net of tax	Accumulated OCI (loss), net of tax
	(Thousands)			
December 31, 2017	\$ 4,625	\$ (555)	\$ (6,528)	\$ (2,458)
(Gains) losses reclassified from accumulated OCI, net of tax	(4,625) (a)	168 (b)	606 (c)	(3,851)
Distribution to Equitrans Midstream Corporation	—	—	903	903
December 31, 2018	—	(387)	(5,019)	(5,406)
Losses reclassified from accumulated OCI, net of tax	—	387 (b)	316 (c)	703
Change in accounting principle	—	—	(496)	(496)
December 31, 2019	—	—	(5,199)	(5,199)
Losses reclassified from accumulated OCI, net of tax	—	—	(156) (c)	(156)
December 31, 2020	\$ —	\$ —	\$ (5,355)	\$ (5,355)

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

(b) Losses, net of tax, related to interest rate cash flow hedges were reclassified from accumulated OCI into interest expense.

(c) Losses, net of tax, related to other postretirement benefits liability adjustments were attributable to net actuarial losses and net prior service costs.

### 13. Share-Based Compensation Plans

The following table summarizes the Company's share-based compensation expense.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Incentive Performance Share Unit Programs	\$ 10,457	\$ 13,306	\$ 14,072
Value Driver Performance Share Unit Award Programs	885	3,376	8,808
Restricted stock awards	10,480	14,430	14,503
Non-qualified stock options	848	4,774	2,757
Stock appreciation rights	2,724	—	—
Other programs, including non-employee director awards	2,155	2,257	3,014
Less: Discontinued operations	—	—	(18,250)
Total share-based compensation expense (a)	<u>\$ 27,549</u>	<u>\$ 38,143</u>	<u>\$ 24,904</u>

(a) For the years ended December 31, 2020 and 2019, share-based compensation expense of \$2.1 million and \$28.6 million, respectively, was included in other operating expenses related primarily to reorganization costs.

In connection with the Separation in 2018, the Company transferred obligations related to then-outstanding share-based compensation awards 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 Company equity and a stock-based compensation award denominated in Equitrans Midstream equity. These awards were adjusted in accordance with the basket method, which resulted in participants retaining one unit of the existing Company incentive award and receiving an additional 0.80 units of an Equitrans Midstream-based award.

The Company recognizes compensation cost related to unvested awards held by its employees, regardless of who settles the obligation. Upon vesting the Company is 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. Likewise, upon vesting, Equitrans Midstream is obligated to settle all of the outstanding share-based compensation awards denominated in its equity, 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. When an award has graduated vesting, the Company records expense equal to the vesting percentage on the vesting date.

The Company typically uses treasury stock to fund awards paid in stock, but the Company can elect to fund such awards 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.

There was no cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2020 and 2019. Cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2018 was \$1.9 million. During the years ended December 31, 2020, 2019 and 2018, share-based payment arrangements paid in stock generated tax benefits of \$1.0 million, \$2.4 million and \$13.4 million, respectively.

#### Incentive Performance Share Unit Programs – Equity & Liability

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

- 2016 Incentive Performance Share Unit Program (2016 Incentive PSU Program) under the 2014 Long-Term Incentive Plan (LTIP);
- 2017 Incentive Performance Share Unit Program (2017 Incentive PSU Program) under the 2014 LTIP;
- 2018 Incentive Performance Share Unit Program (2018 Incentive PSU Program) under the 2014 LTIP;
- 2019 Incentive Performance Share Unit Program (2019 Incentive PSU Program) under the 2014 LTIP; and
- 2020 Incentive Performance Share Unit Program (2020 Incentive PSU Program) under the 2019 LTIP.

The programs noted above are collectively referred to as the Incentive PSU Programs. The 2016 Incentive PSU Program and 2020 Incentive PSU Program granted equity awards. The 2017 Incentive PSU Program, 2018 Incentive PSU Program and 2019 Incentive PSU Program granted both equity and liability awards.

The Incentive PSU Programs were established to provide long-term incentive opportunities to executives and 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 2016 and 2017 were earned based on:

- 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.

Executive performance incentive program awards granted in years 2018 and 2019 were earned based on:

- 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.

Beginning in 2020, executive performance incentive program awards granted are earned based on:

- adjusted well costs;
- adjusted free cash flow; and
- the level of total shareholder return relative to a predefined peer group.

Prior to 2020, the payout factor varies between zero and 300% of the number of outstanding units contingent upon the performance metrics listed above. The 2020 Incentive PSU Program has a payout factor that ranges from zero to 150%. The Company recorded the 2016 Incentive PSU Program, 2020 Incentive PSU Program and the portion of the 2017 Incentive PSU Program, 2018 Incentive PSU Program and 2019 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 end point of the performance period. The 2017 Incentive PSU Program, 2018 Incentive PSU Program and 2019 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 end 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. 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. Vesting of the units under each Incentive PSU Program occurs upon payment after the end of the performance period.

The following table summarizes Incentive PSU Programs to be settled in stock and classified as equity awards:

Incentive PSU Programs - Equity Settled	Nonvested Shares (a)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2018	832,622	\$ 115.10	\$ 95,832,997
Granted	172,350	76.53	13,189,946
Vested	(306,407)	141.11	(43,237,092)
Forfeited	(162,551)	93.55	(15,206,691)
Outstanding at December 31, 2018	536,014	94.36	50,579,160
Granted	463,380	29.45	13,646,541
Vested	(384,101)	96.30	(36,988,926)
Outstanding at December 31, 2019	615,293	44.27	27,236,775
Granted	1,376,198	6.62	9,107,846
Vested	(44,573)	120.60	(5,375,504)
Forfeited	(7,190)	13.28	(95,483)
Outstanding at December 31, 2020	1,939,728	\$ 15.92	\$ 30,873,634

(a) For the years ended December 31, 2020 and 2019, the Company settled total shares of 7,020 and 130,393, respectively, for Equitrans Midstream employees.

The following table summarizes Incentive PSU Programs to be settled in cash and classified as liability awards:

Incentive PSU Programs - Cash Settled	Nonvested Shares (b)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2018	117,530	\$ 120.60	\$ 14,174,118
Granted	142,890	76.53	10,935,371
Forfeited	(30,582)	94.56	(2,891,844)
Outstanding at December 31, 2018	229,838	96.67	22,217,645
Granted	255,920	29.45	7,536,844
Forfeited	(33,348)	75.65	(2,522,819)
Outstanding at December 31, 2019	452,410	60.19	27,231,670
Vested	(93,359)	120.60	(11,259,095)
Forfeited	(19,356)	61.43	(1,189,050)
Outstanding at December 31, 2020	339,695	\$ 43.52	\$ 14,783,525

(b) For the year ended December 31, 2020, the Company settled total shares paid in cash of 40,018 for Equitrans Midstream employees.

Total capitalized compensation costs related to the Incentive PSU Programs for the years ended December 31, 2020, 2019, and 2018 were \$0.9 million, \$(0.8) million, and \$3.7 million. As of December 31, 2020, \$0.1 million, \$0.8 million and \$6.2 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2019 Incentive PSU Program – Equity, 2019 Incentive PSU Program – Liability and 2020 Incentive PSU Program, respectively, was expected to be recognized over the remainder of the performance periods.

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

	Incentive PSU Programs Issued During the Years Ended December 31,				
	2020 (a)	2019	2018	2017	2016
Risk-free rate	1.22%	2.44%	1.97%	1.47%	1.31%
Volatility factor	45.41%	54.60%	32.60%	32.30%	28.43%
Expected term	3 years	3 years	3 years	3 years	3 years

Dividends paid from the beginning of the performance period will be cumulatively added as additional shares of common stock; therefore, dividend yield is not applicable.

(a) There were three grant dates for the 2020 Incentive PSU Program. Amounts shown represent weighted average.

### Value Driver Performance Share Unit Award Programs

Historically, the Compensation Committee adopted the following programs, collectively referred to as the VDPSU Programs:

- 2017 Value Driver Performance Share Unit Award Program (2017 EQT VDPSU Program) under the 2014 LTIP;
- 2018 Value Driver Performance Share Unit Award Program (2018 EQT VDPSU Program) under the 2014 LTIP; and
- 2019 Value Driver Performance Share Unit Award Program (2019 EQT VDPSU Program) under the 2014 LTIP.

The programs noted above 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 confirmed awards vested upon payment following the first anniversary of the grant date; the remaining 50% of the confirmed awards vested 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 were 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. The following table provides additional detailed information on each historical award.

VDPSU Program	Accounting Treatment	Weighted Average Fair Value	Cash paid (Millions)	Awards Outstanding (including accrued dividends) as of December 31, 2020 (a)
2017	Liability	\$ 65.40	\$ 14.0	N/A
		\$ 65.40	\$ 4.0	N/A
2018	Liability	\$ 56.92	\$ 4.9	N/A
		\$ 56.92	\$ 1.2	N/A
2019 (b)	Liability	\$ 18.89	\$ 1.7	N/A
		\$ 18.89	N/A	144,116

(a) The 2017 EQT VDPSU Program and 2018 EQT VDPSU Program included 95,452 and 130,355 awards, respectively, for Equitrans Midstream employees that were settled by the Company.

(b) The total liability recorded for the 2019 EQT VDPSU Program was \$1.7 million as of December 31, 2020. The second tranche of the 2019 EQT VDPSU Program will be paid during the first quarter of 2021.

Total capitalized compensation costs related to the VDPSU Programs for the years ended December 31, 2020, 2019 and 2018 were \$0.4 million, \$2.5 million and \$3.4 million, respectively.

### Restricted Stock Unit Awards – Equity

The Company granted 1,767,960, 613,440 and 145,540 restricted stock unit equity awards to key employees of the Company during the years ended December 31, 2020, 2019 and 2018, respectively. Awards granted in 2019 and 2018 will fully vest at the end of the three-year period commencing with the date of grant, assuming continued service through such date, while the 2020 awards are subject to a three-year graded vesting schedule, also assuming continued service through such date. For the years ended December 31, 2020, 2019 and 2018, the weighted average fair value of these restricted stock grants, based on the grant date fair value of EQT common stock, was approximately \$10.02, \$17.42 and \$54.33, respectively.

The total fair value of restricted stock awards vested during the years ended December 31, 2020, 2019 and 2018 was \$3.2 million, \$11.9 million and \$39.8 million, respectively. Total capitalized compensation costs related to the restricted stock unit equity awards was \$3.0 million for the year ended December 31, 2020.

As of December 31, 2020, \$9.3 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 1.1 years.

The following table summarizes restricted stock equity award activity as of December 31, 2020.

Restricted Stock - Equity Settled	Nonvested Shares (a)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2020	310,997	\$ 25.47	\$ 7,921,313
Granted	1,767,960	10.02	17,711,033
Vested	(130,487)	24.26	(3,165,269)
Forfeited	(80,070)	10.90	(872,763)
Outstanding at December 31, 2020	1,868,400	\$ 11.56	\$ 21,594,314

(a) Nonvested shares outstanding at December 31, 2020 includes 59,340 shares for an Equitrans Midstream employee that will be settled by the Company.

### Restricted Stock Unit Awards – Liability

During the years ended December 31, 2019 and 2018, the Company granted 686,350 and 373,750 restricted stock unit liability awards, respectively, to key employees of the Company that will be paid in cash. The Company did not grant restricted stock unit awards to be paid in cash during 2020.

Adjusted for forfeitures, there were 554,306 awards outstanding as of December 31, 2020. Because these awards are liability awards, the Company records compensation expense based on 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 \$4.5 million, \$4.4 million and \$6.9 million as of December 31, 2020, 2019 and 2018, respectively.

### Non-Qualified Stock Options

The fair value of the Company's option grants was estimated at the grant date using a Black-Scholes option-pricing model with the assumptions indicated in the table below for the years ended December 31, 2020, 2019 and 2018. 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 EQT common stock at the time of grant. Expected volatilities are based on historical volatility of EQT common stock. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience.

	Years Ended December 31,		
	2020	2019 (a)	2018
Risk-free interest rate	1.10 %	2.48 %	2.25 %
Dividend yield	— %	0.46 %	0.20 %
Volatility factor	60.00 %	27.97 %	26.46 %
Expected term	4 years	5 years	5 years
Number of Options Granted	1,000,000	779,300	287,800
Weighted Average Grant Date Fair Value	\$ 1.61	\$ 5.31	\$ 15.39
Total Intrinsic Value of Options Exercised (Millions)	\$ —	\$ —	\$ —

(a) There were two grant dates for the 2019 options. Amount shown represents weighted average.

As of December 31, 2020, \$0.8 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2023.

The following table summarizes option activity as of December 31, 2020.

Non-Qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2020	2,554,729	\$ 28.37		
Granted	1,000,000	10.00		
Outstanding at December 31, 2020	3,554,729	23.20	5.3 years	\$ 2,710,000
Exercisable at December 31, 2020	2,543,829	\$ 28.41	4.9 years	\$ —

### Stock Appreciation Rights

During 2020, the Company granted stock appreciation rights subject to certain performance conditions, such as adjusted well costs and adjusted free cash flow. Once vested, the participant is entitled to receive, upon exercise, a number of shares of EQT's common stock, cash or a combination of the two, based upon the excess of the fair market value as of the date of exercise over a base price of \$10.00.

The awards are accounted for as liability awards and, as such, compensation expense is recorded based on the fair value of the awards as remeasured at the end of each reporting period using a Black-Scholes option-pricing model with the assumptions indicated in the table below. The risk-free rate is based on the U.S. Treasury yield curve in effect at the reporting date. The dividend yield is based on the dividend yield of EQT common stock at the reporting date, which is set at zero for the stock appreciation rights as the Company suspended future dividends during 2020. Expected volatilities are based on a 50-50 blend of the expected term-matched historical volatility as of the valuation date and the weighted-average implied volatility from thirty

days prior to the valuation date. The expected term represents the period of time between the valuation date and the midpoint of the exercise window.

2020 Stock Appreciation Rights	
Risk-free interest rate	0.30 %
Dividend yield	— %
Volatility factor	67.50 %
Expected term	3.28 years
Number of Stock Appreciation Rights Granted	1,240,000
Weighted Average Grant Date Fair Value	\$ 2.61
Total Intrinsic Value of Exercises (Millions)	\$ —

As of December 31, 2020, \$4.7 million of unrecognized compensation cost related to outstanding stock appreciation rights was expected to be recognized by December 31, 2022.

The following table summarizes stock appreciation rights activity as of December 31, 2020.

Stock Appreciation Rights	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2020	—	\$ —		
Granted	1,240,000	10.00		
Outstanding at December 31, 2020	1,240,000	10.00	9.0 years	\$ 3,360,400
Exercisable at December 31, 2020	—	\$ —	—	\$ —

#### Non-employee Directors' Share-Based Awards

Prior to 2020, the Company granted share-based awards that vested upon grant to non-employee directors. The share-based awards were historically paid in cash or EQT common stock following a directors' termination of service on the Company's Board of Directors. Beginning in 2020, the Company grants to non-employee directors restricted stock unit awards that vest on the date of the Company's annual meeting of shareholders immediately following the grant of such awards. The restricted stock unit awards are settled in EQT common stock on the vesting date or, if elected by the director, following a director's termination of service on the Company's Board of Directors.

Awards to be paid in cash are accounted for as liability awards and, as such, compensation expense is recorded based on the fair value of the awards as remeasured at the end of each reporting period. Awards to be settled in EQT common stock are accounted for as equity awards and, as such, compensation expense is recorded based on the fair value of the awards at the grant date fair value. A total of 398,456 non-employee director share-based awards, including accrued dividends, were outstanding as of December 31, 2020. A total of 201,300, 146,790 and 50,979 share-based awards were granted to non-employee directors during the years ended December 31, 2020, 2019 and 2018, respectively. The weighted average fair value of these grants, based on the closing EQT common stock price on the business day prior to the grant date, was \$13.46, \$18.11 and \$52.65 for the years ended December 31, 2020, 2019 and 2018, respectively.

#### Subsequent Events - 2021 Awards

Effective in 2021, the Compensation Committee adopted the 2021 Incentive Performance Share Unit Program (2021 Incentive PSU Program) under the 2020 LTIP. The 2021 Incentive PSU Program was established to align the interests of executives and key employees with the interests of shareholders and the strategic objectives of the Company. A total of 922,260 units were granted under the 2021 Incentive PSU Program. The payout of the stock units will vary between zero and 200% of the number of outstanding units contingent upon a combination of the Company's absolute total shareholder return and total shareholder return relative to a predefined peer group over the period January 1, 2021 through December 31, 2023.

Effective in 2021, the Compensation Committee granted 1,889,510 restricted stock equity awards that will follow a three-year graded vesting schedule commencing with the date of grant, assuming continued employment. The share total includes the newly instituted "equity-for-all" program, which granted equity awards to all permanent full-time employees beginning in 2021.

#### **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 oil to marketers, utilities and industrial customers located in the Appalachian Basin and in markets that are accessible through the Company's transportation portfolio, which includes markets in the Gulf Coast, Midwest and Northeast United States and Canada. The Company also contracts with certain processors to market a portion of NGLs on behalf of the Company. We do not depend on any single customer and believe that the loss of any one customer would not have an adverse effect on our ability to sell our natural gas, NGLs and oil.

Approximately 86% and 62% of the Company's accounts receivable balances as of December 31, 2020 and 2019, respectively, represent amounts due from non-end users. The Company manages the credit risk of sales to non-end users by limiting its dealings with only non-end users 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 non-end user for that non-end user to meet the Company's credit criteria. The Company did not experience any significant defaults on sales of natural gas to non-end users during the years ended December 31, 2020, 2019 or 2018.

The Company is exposed to credit loss in the event of nonperformance by counterparties to its 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. The Company uses various processes and analyses to monitor and evaluate its credit risk exposures, including monitoring current market conditions and counterparty credit fundamentals. 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, 2020, 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, 2020, the Company made no adjustments to the fair value of its 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 its derivative contracts.

#### **15. Leases**

The Company primarily leases drilling rigs, other drilling equipment and facilities.

On January 1, 2019, in connection with the Company's adoption of ASU 2016-02, *Leases*, the Company recorded in its Consolidated Balance Sheet \$89.0 million of right-of-use assets and lease liabilities representing the present value of the Company's right to use its leased assets and obligation to make lease payments on those leased assets, respectively.

To determine the present value of its right-of-use assets and lease liabilities at adoption and thereafter, the Company calculates a discount rate per lease contract based on an estimate of the rate of interest that the Company would pay to borrow (on a collateralized-basis over a similar term) an amount equal to the lease payment obligation.

Upon adoption of ASU 2016-02, the Company elected a practical expedient to forgo application of the recognition requirements under the standard to short-term leases; as such, short-term leases are not recorded in the Consolidated Balance Sheets. In addition, the Company elected a practical expedient to account for lease and nonlease components together as a lease.

Certain of the Company's lease contracts include variable lease payments, such as property taxes, other operating and maintenance expenses and payments based on asset use, which are not included in operating lease cost or the present value of the right-of-use asset or lease liability. Certain of the Company's lease contracts provide renewal periods at the Company's option; if a renewal period option is reasonably assured to be exercised, the associated lease payment obligations are included in the present value of the right-of-use asset and lease liability. As of December 31, 2020 and 2019, the Company was not a lessor.

The following table summarizes the Company's lease costs.

	Years Ended December 31,	
	2020	2019
	(Thousands)	
Operating lease costs	\$ 28,286	\$ 57,517
Variable lease costs (a)	15,922	17,143
Total lease costs (b)	\$ 44,208	\$ 74,660

(a) Includes short-term lease costs.

(b) For the years ended December 31, 2020 and 2019, includes drilling rig lease costs capitalized to property, plant and equipment of \$29.9 million and \$58.5 million, respectively, of which \$19.9 million and \$48.1 million, respectively, were operating lease costs.

During the fourth quarter of 2020, the Company recognized \$22.8 million of right-of-use asset impairment in impairment of intangible and other assets in the Statement of Consolidated Operations as a result of the Company's assessment that the fair values of certain of the Company's right-of-use assets were less than their carrying values.

For the years ended December 31, 2020 and 2019, cash paid for lease liabilities and reported in cash flows provided by operating activities in the Statements of Consolidated Cash Flows was \$10.4 million and \$10.8 million, respectively. During the years ended December 31, 2020 and 2019, the Company recorded \$18.9 million and \$24.3 million, respectively, of right-of-use assets in exchange for new lease liabilities.

The Company records its right-of-use assets in other assets and the current and noncurrent portions of its lease liabilities in other current liabilities and other liabilities and credits, respectively, in the Consolidated Balance Sheets. As of December 31, 2020 and 2019, right-of-use assets were \$21.6 million and \$52.2 million, respectively, and lease liabilities were \$49.9 million and \$59.0 million, respectively, of which \$25.0 million and \$29.0 million, respectively, were classified as current. As of December 31, 2020 and 2019, the weighted average remaining lease term was 2.8 years and 3.3 years, respectively. As of both December 31, 2020 and 2019, the weighted average discount rate was 3.3%.

The following table summarizes the Company's lease payment obligations as of December 31, 2020.

	December 31, 2020
	(Thousands)
2021	\$ 26,197
2022	9,841
2023	9,764
2024	6,456
2025	150
Total lease payment obligations	52,408
Less: Interest	2,495
Present value of lease liabilities	\$ 49,913

## 16. 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. Aggregate future payments for these items as of December 31, 2020 were \$24.8 billion, composed of \$1.3 billion in 2021, \$1.7 billion in 2022, \$1.8 billion in 2023, \$1.9 billion in 2024, \$1.8 billion in 2025 and \$16.3 billion thereafter. The Company also has commitments to purchase equipment, materials, frac sand for use as a proppant in its hydraulic fracturing operations and minimum volume commitments associated with certain water agreements. As of December 31, 2020, future commitments under these contracts were \$96.5 million in 2021 and \$14.3 million in 2022.

See Note 15 for a summary of undiscounted future cash flows owed by the Company as lessee to lessors pursuant to contractual agreements in effect as of December 31, 2020.

Conditioned upon the credit ratings assigned by Moody's, S&P and Fitch to the Company's senior notes, counterparties to the Company's derivative and midstream services contracts may request additional assurances of the Company, including collateral. See Note 3 for a discussion of what is deemed investment grade and other factors affecting margin deposit requirements on the

Company's derivative contracts as well as collateral posted as of December 31, 2020. See Note 10 for a discussion of letters of credit outstanding and surety bonds posted as of December 31, 2020.

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 position, results of operations or liquidity of the Company.

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 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, results of operations or liquidity. The Company has identified situations that require remedial action for which approximately \$18.9 million was recorded in other liabilities and credits in the Consolidated Balance Sheet as of December 31, 2020.

## 17. Guarantees

In connection with the sale of its NORESCO domestic operations in 2005, the Company agreed to maintain in-place guarantees of certain warranty obligations of NORESCO. The savings guarantees provided that, once an energy-efficiency construction project was completed by NORESCO, the customer would experience a certain dollar amount of energy savings over a number of years. The undiscounted maximum aggregate payments that may be due related to these guarantees were approximately \$44 million as of December 31, 2020, extending at a decreasing amount for approximately 8 years.

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

## 18. Natural Gas Producing Activities (Unaudited)

The following supplementary information summarized 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 total aggregate capitalized costs and costs incurred related to natural gas, NGLs and oil production activities.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
<b>Capitalized costs</b>			
Proved properties	\$ 19,479,211	\$ 17,994,820	\$ 17,648,731
Unproved properties	2,291,814	3,322,014	4,166,048
Total capitalized costs	21,771,025	21,316,834	21,814,779
Less: Accumulated depreciation and depletion	5,866,418	5,402,515	4,666,212
Net capitalized costs	\$ 15,904,607	\$ 15,914,319	\$ 17,148,567

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
<b>Costs incurred (a)</b>			
Property acquisition:			
Proved properties (b)	\$ 761,940	\$ 40,316	\$ 77,099
Unproved properties (c)	78,404	154,128	198,854
Exploration	5,484	7,223	1,708
Development	947,233	1,560,346	2,443,980

(a) Amounts exclude capital expenditures for facilities, information technology and other corporate items.

(b) Amounts in 2020 include \$674.0 million and \$6.5 million for the purchase of Marcellus and Utica wells, respectively, associated with the Chevron Acquisition. Amounts in 2018 include \$5.2 million and \$9.2 million for the purchase of Marcellus and Utica wells, respectively, including the impact of measurement period adjustments for 2017 acquisitions.

(c) Amounts in 2020 include \$38.9 million for the purchase of unproved properties associated with the Chevron Acquisition.

### Results of Operations for Producing Activities

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

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Sales of natural gas, NGLs and oil	\$ 2,650,299	\$ 3,791,414	\$ 4,695,519
Transportation and processing	1,710,734	1,752,752	1,697,001
Production	155,403	153,785	195,775
Exploration	5,484	7,223	6,765
Depreciation and depletion	1,393,465	1,538,745	1,569,038
Impairment/loss on sale/exchange of long-lived assets	100,729	1,138,287	2,709,976
Impairment and expiration of leases	306,688	556,424	279,708
Income tax benefit	(254,671)	(340,843)	(454,009)
Results of operations from producing activities, excluding corporate overhead	\$ (767,533)	\$ (1,014,959)	\$ (1,308,735)

### Reserve Information

Proved developed reserves represent only those reserves expected to be recovered from existing wells and support equipment. Proved undeveloped reserves represent proved reserves expected to be recovered from new wells after substantial development costs are incurred.

The Company's estimate of proved natural gas, NGLs and crude oil reserves was prepared by Company engineers. The engineer primarily responsible for overseeing the preparation of the reserves estimate holds a bachelor's degree in chemical engineering from Michigan Technological University, a master's degree in chemical engineering from Colorado State University and an executive master of business administration in energy from the University of Oklahoma and has 20 years of experience in the oil and gas industry. To support the accurate and timely preparation and disclosure of its reserve estimates, the Company established internal controls over its reserve estimation processes and procedures, including the following: the price, heat content conversion rate and cost assumptions used in the economic model to determine the reserves are reviewed by management; division of interest and production volumes are reconciled between the system used to calculate the reserves and other accounting/measurement systems; the reserves reconciliation between prior year reserves and current year reserves is reviewed by senior management; and the estimates of proved natural gas, NGLs and crude oil reserves are audited by Netherland, Sewell & Associates, Inc. (NSAI), an independent consulting firm hired by management. Since 1961, NSAI has evaluated oil and gas properties and independently certified petroleum reserves quantities in the United States and internationally.

In the course of its audit, NSAI conducted a detailed review of 100% of the total net natural gas, NGLs and oil proved reserves attributable to the Company's interests as of December 31, 2020. NSAI conducted a detailed, well-by-well audit of all the

Company's properties. The estimates prepared by the Company and audited by NSAI were within the recommended 10% tolerance threshold set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy and material balance were utilized in the evaluation of reserves. All of the Company's proved reserves are located in the United States.

For all tables presented, NGLs and oil were converted at a rate of one Mbbl to approximately six million cubic feet (MMcf).

	Years Ended December 31,		
	2020	2019	2018
	(MMcf)		
Natural gas, NGLs and oil			
Proved developed and undeveloped reserves:			
Balance at January 1	17,469,394	21,816,776	21,445,667
Revision of previous estimates	(739,213)	(4,907,239)	(1,124,904)
Purchase of hydrocarbons in place	1,380,564	—	—
Sale of hydrocarbons in place	(256,663)	—	(1,748,557)
Extensions, discoveries and other additions	3,445,802	2,067,753	4,739,233
Production	(1,497,792)	(1,507,896)	(1,494,663)
Balance at December 31	19,802,092	17,469,394	21,816,776
Proved developed reserves:			
Balance at January 1	12,443,987	11,550,161	11,297,956
Balance at December 31	13,641,345	12,443,987	11,550,161
Proved undeveloped reserves:			
Balance at January 1	5,025,407	10,266,615	10,147,711
Balance at December 31	6,160,747	5,025,407	10,266,615
	Years Ended December 31,		
	2020	2019	2018
	(MMcf)		
Natural gas			
Proved developed and undeveloped reserves:			
Balance at January 1	16,677,202	20,805,452	19,830,236
Revision of previous estimates	(781,668)	(4,722,799)	(960,285)
Purchase of natural gas in place	1,209,326	—	—
Sale of natural gas in place	(254,930)	—	(1,331,391)
Extensions, discoveries and other additions	3,433,857	2,029,683	4,659,835
Production	(1,418,774)	(1,435,134)	(1,392,943)
Balance at December 31	18,865,013	16,677,202	20,805,452
Proved developed reserves:			
Balance at January 1	11,811,521	10,887,953	10,152,543
Balance at December 31	12,750,312	11,811,521	10,887,953
Proved undeveloped reserves:			
Balance at January 1	4,865,681	9,917,499	9,677,693
Balance at December 31	6,114,701	4,865,681	9,917,499

	Years Ended December 31,		
	2020	2019	2018
	(Mbbl)		
NGLs			
Proved developed and undeveloped reserves:			
Balance at January 1	126,955	162,395	258,507
Revision of previous estimates	6,825	(30,312)	(33,653)
Purchase of NGLs in place	25,879	—	—
Sale of NGLs in place	(289)	—	(59,080)
Extensions, discoveries and other additions	1,757	6,177	12,895
Production	(12,365)	(11,305)	(16,274)
Balance at December 31	148,762	126,955	162,395
Proved developed reserves:			
Balance at January 1	100,945	106,879	180,170
Balance at December 31	141,489	100,945	106,879
Proved undeveloped reserves:			
Balance at January 1	26,010	55,516	78,337
Balance at December 31	7,273	26,010	55,516
	Years Ended December 31,		
	2020	2019	2018
	(Mbbl)		
Oil			
Proved developed and undeveloped reserves:			
Balance at January 1	5,077	6,159	10,731
Revision of previous estimates	250	(428)	6,217
Purchase of oil in place	2,660	—	—
Sale of oil in place	—	—	(10,447)
Extensions, discoveries and other additions	234	168	338
Production	(804)	(822)	(680)
Balance at December 31	7,417	5,077	6,159
Proved developed reserves:			
Balance at January 1	4,466	3,489	10,731
Balance at December 31	7,016	4,466	3,489
Proved undeveloped reserves:			
Balance at January 1	611	2,670	—
Balance at December 31	401	611	2,670

The change in reserves during the year ended December 31, 2020 resulted from the following:

- Conversions of 2,102 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 3,446 Bcfe, which exceeded 2020 production of 1,498 Bcfe. Extensions, discoveries and other additions included an increase of 2,096 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved using reliable technologies which expanded the number of our technically proven locations, 1,295 Bcfe due to additions associated with directly offsetting development, 31 Bcfe from extension of proved undeveloped reserves lateral lengths and 24 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 510 Bcfe from proved undeveloped locations that are no longer expected to be developed within five years of initial booking as proved reserves as a result of revisions to the Company's five-year drilling plan allowing for continued alignment with the Company's combo-development strategy. This includes 245 Bcfe from lower pricing that impacted well economics, shifting capital from the Ohio Utica, to Pennsylvania and West Virginia Marcellus, and 265 Bcfe as a result of continued implementation of the Company's combo-development strategy.

- Negative revisions of 384 Bcfe primarily from proved developed locations as a result of negative curve revisions in Ohio Utica.
- Positive revisions to proved undeveloped locations of 155 Bcfe due primarily to changes in working interests and net revenue interests as well as type curve updates.
- Purchase of hydrocarbons in place of 1,381 Bcfe due to the Chevron Acquisition described in Note 6.
- Sale of hydrocarbons in place of 257 Bcfe due to the 2020 Divestitures described in Note 7.

The change in reserves during the year ended December 31, 2019 resulted from the following:

- Conversions of 2,646 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 2,068 Bcfe, which exceeded 2019 production of 1,508 Bcfe. Extensions, discoveries and other additions included an increase of 1,796 Bcfe from proved undeveloped additions associated with acreage that was previously unproved, but became proved due to 2019 reserve development that expanded the number of the Company's technically proven locations, implementation of, and alignment with, the Company's combo-development strategy and revisions to the Company's five-year drilling plan; 156 Bcfe from converting unproved reserves to proved developed reserves; and 116 Bcfe from extension of proved undeveloped reserves lateral lengths.
- Negative revisions of 4,508 Bcfe from proved undeveloped locations that are no longer expected to be developed within five years of initial booking as proved reserves as a result of implementation of the Company's combo-development strategy, which has refocused operations in the Company's core assets and driven execution of new development sequencing processes that emphasize productivity. While these efforts are expected to result in decreased well costs, they negatively impact proved undeveloped reserves as a result of (i) derecognizing previously-recorded proved undeveloped reserves that are now outside the Company's substantially revised five-year capital allocation program for purposes of the Company's reserves calculations and (ii) executing new development sequencing processes that will result in increased probable-to-proved developed conversion.

The change in reserves during the year ended December 31, 2018 resulted from the following:

- Conversions of 2,722 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 4,739 Bcfe, which exceeded 2018 production of 1,495 Bcfe. Extensions, discoveries and other additions included an 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; 886 Bcfe from proved undeveloped reserves extensions from acreage proved by drilling activity in the Company's Ohio, Pennsylvania and West Virginia Marcellus fields; and 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.
- 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 as a result of 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 from proved developed locations, due primarily to increased reserves from producing wells and improved commodity prices.
- Sale of hydrocarbons in place of 1,749 Bcfe due to the 2018 Divestitures described in Note 7.

#### **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 following table summarizes estimated future net cash flows from natural gas and crude oil reserves.

	December 31,		
	2020	2019	2018
	(Thousands)		
Future cash inflows (a)	\$ 27,976,557	\$ 42,499,686	\$ 60,603,624
Future production costs (b)	(16,344,965)	(19,114,076)	(20,463,567)
Future development costs	(2,268,109)	(2,617,731)	(5,854,503)
Future income tax expenses	(1,820,341)	(3,013,667)	(6,823,621)
Future net cash flow	7,543,142	17,754,212	27,461,933
10% annual discount for estimated timing of cash flows	(4,176,684)	(9,261,539)	(15,850,035)
Standardized measure of discounted future net cash flows	\$ 3,366,458	\$ 8,492,673	\$ 11,611,898

(a) The majority of the Company's production is sold through liquid trading points on interstate pipelines.

For 2020, reserves were computed using average first-day-of-the-month closing prices for the prior twelve months of \$39.54 per Bbl for West Texas Intermediate (WTI) less regional adjustments of \$18.60 per Bbl, or \$20.94 per Bbl, and \$1.985 per MMBtu for NYMEX less regional adjustments of \$0.68 per MMBtu, or \$1.38 per Mcf. Regional adjustments were calculated using historical average realized prices received by the Company in the Appalachian Basin. For 2020, NGL pricing using average first-day-of-the-month closing prices for the prior twelve months for NGL components, adjusted using the regional component makeup of proved NGLs, resulted in a price of \$11.97 per Bbl.

For 2019, reserves were computed using average first-day-of-the-month closing prices for the prior twelve months of \$55.69 per Bbl for WTI less regional adjustments of \$14.26 per Bbl, or \$41.43 per Bbl, and \$2.58 per MMBtu for NYMEX less regional adjustments of \$0.29 per MMBtu, or \$2.41 per Mcf. Regional adjustments were calculated using historical average realized prices received by the Company in the Appalachian Basin. For 2019, NGL pricing using average first-day-of-the-month closing prices for the prior twelve months for NGL components, adjusted using the regional component makeup of proved NGLs, resulted in a price of \$16.81 per Bbl.

For 2018, reserves were computed using average first-day-of-the-month closing prices for the prior twelve months of \$65.56 per Bbl for 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 average first-day-of-the-month closing prices for the prior twelve months for NGL components, adjusted using the regional component makeup of produced NGLs, resulted in prices of \$21.93 per Bbl from certain West Virginia Marcellus reserves and \$33.89 per Bbl from Ohio Utica reserves.

(b) Includes approximately \$1,554 million, \$1,186 million and \$883 million for future plugging and abandonment costs as of December 31, 2020, 2019 and 2018, respectively.

Holding production and development costs constant, an increase in price of \$0.10 per Dth for natural gas, \$10 per barrel for NGLs and \$10 per barrel for oil would result in a change in the December 31, 2020 discounted future net cash flows before income taxes of the Company's proved reserves of approximately \$929 million, \$241 million and \$630 million, respectively.

The following table summarizes the changes in the standardized measure of discounted future net cash flows.

	Years Ended December 31,		
	2020	2019	2018
	(Thousands)		
Net sales and transfers of natural gas and oil produced	\$ (784,163)	\$ (1,884,877)	\$ (2,802,742)
Net changes in prices, production and development costs	(6,761,447)	(3,502,434)	2,949,606
Extensions, discoveries and improved recovery, net of related costs	714,808	870,504	1,616,653
Development costs incurred	797,796	1,002,389	1,630,506
Net purchase of minerals in place	350,075	—	—
Net sale of minerals in place	(226,497)	—	(849,162)
Revisions of previous quantity estimates	(324,415)	(2,080,040)	(811,576)
Accretion of discount	849,267	900,004	834,026
Net change in income taxes	152,978	1,444,368	(289,549)
Timing and other	105,383	130,861	332,202
Net (decrease) increase	(5,126,215)	(3,119,225)	2,609,964
Balance at January 1	8,492,673	11,611,898	9,001,934
Balance at December 31	\$ 3,366,458	\$ 8,492,673	\$ 11,611,898

#### 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 Company's management 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). The Company'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.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2020. 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, 2020. Management's assessment of, and conclusion on, the effectiveness of internal control over financial reporting did not include the internal controls of the assets acquired in the Chevron Acquisition on November 30, 2020. Total assets acquired and total operating revenues represented approximately 5% of the Company's consolidated total assets at December 31, 2020 and less than 1% of the Company's consolidated total operating revenues for the year ended December 31, 2020.

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 herein by reference.

#### ***Changes in Internal Control over Financial Reporting***

There were no changes in internal control over financial reporting (as such term is defined in Rule 13a-15(f) under the Exchange Act) that occurred during the fourth quarter of 2020 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

The Company is in the process of integrating the assets acquired in the Chevron Acquisition into the Company's internal controls over financial reporting.

#### **Item 9B. Other Information**

Not Applicable.

### **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 2021 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, 2020:

- Information required by Item 401 of Regulation S-K with respect to directors is incorporated herein by reference from the sections captioned "Director Nominees" and "Director Independence" under "Corporate Governance and Board Matters" 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 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 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 "Information about our Executive Officers (as of February 17, 2021)," 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 "About" link on the main page, followed by the "Governance" heading, then the "Charters and Governance 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 2021 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, 2020:

- 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 "Compensation Discussion and

Analysis," "Compensation Tables," "Compensation Policies and Practices and Risk Management," "Pay Ratio Disclosure" and "Corporate Governance and Board Matters – Directors' Compensation" in the Company's definitive proxy statement; and

- Information required by paragraph (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 section captioned "Compensation Committee Report" 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 – Security Ownership of Certain Beneficial Owners" and "Equity Ownership – Security Ownership of Management" in the Company's definitive proxy statement relating to the 2021 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, 2020.

### Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2020 with respect to shares of the Company's common stock that may be issued under the Company's existing equity compensation plans, including the 2020 Long-Term Incentive Plan (2020 LTIP), 2019 Long-Term Incentive Plan (2019 LTIP), 2014 Long-Term Incentive Plan (2014 LTIP), the 2009 Long-Term Incentive Plan (2009 LTIP), the 2008 Employee Stock Purchase Plan (2008 ESPP), and the 2005 Directors' Deferred Compensation Plan (2005 DDCP):

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)	10,333,813 (2)	\$ 19.79 (3)	12,337,169 (4)
Equity Compensation Plans Not Approved by Shareholders (5)	45,709 (6)	N/A	127,135 (7)
Total	10,379,522	\$ 19.79	12,464,304

(1) Consists of the 2020 LTIP, 2019 LTIP, 2014 LTIP, the 2009 LTIP, and the 2008 ESPP. Effective as of May 1, 2020, with the adoption of the 2020 LTIP, the Company ceased making new grants under the 2019 LTIP. Effective as of July 10, 2019 in connection with the adoption of the 2019 LTIP, the Company ceased making new grants under the 2014 LTIP. 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. The 2019 LTIP, 2014 LTIP, and the 2009 LTIP remain effective solely for the purpose of issuing shares upon the exercise or payout of awards outstanding under such plans on May 1, 2020 (for the 2019 LTIP), July 10, 2019 (for the 2014 LTIP) and April 30, 2014 (for the 2009 LTIP).

(2) Consists of (i) 2,053,512 shares subject to outstanding performance awards under the 2019 LTIP, inclusive of dividend reinvestments thereon (counted at a 3X multiple assuming maximum performance is achieved under the awards (representing 1,369,008 *target* awards and dividend reinvestments thereon)), (ii) 2,240,000 shares subject to outstanding stock options and stock appreciation rights under the 2019 LTIP, (iii) 33,886 shares subject to outstanding directors' deferred stock units under the 2019 LTIP, inclusive of dividend reinvestments thereon, (iv) 3,311,745 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 2,304,439 *target and confirmed* awards and dividend reinvestments thereon)), (v) 1,598,415 shares subject to outstanding stock options under the 2014 LTIP, (vi) 117,680 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon, (vii) 956,314 shares subject to outstanding stock options under the 2009 LTIP; and (viii) 22,261 shares subject to outstanding directors' deferred stock units under the 2009 LTIP, inclusive of dividend reinvestments thereon.

(3) The weighted-average exercise price is calculated solely based on outstanding stock options and stock appreciation rights under the 2019 LTIP, 2014 LTIP and the 2009 LTIP and excludes deferred stock units under the 2019 LTIP, 2014 LTIP, and the 2009 LTIP

and performance awards under the 2019 LTIP, 2014 LTIP and 2009 LTIP. The weighted average remaining term of the outstanding stock options and stock appreciation rights was 5.3 years and 9.0 years, respectively, as of December 31, 2020.

- (4) Consists of (i) 12,044,453 shares available for future issuance under the 2020 LTIP and (ii) 292,716 shares available for future issuance under the 2008 ESPP. As of December 31, 2020, no shares were subject to purchase under the 2008 ESPP.
- (5) Consists of the 2005 DDCP which is described below.
- (6) Consists entirely of shares invested in the EQT common stock fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP as of December 31, 2020.
- (7) Consists entirely of shares available for future issuance under the 2005 DDCP as of December 31, 2020.

#### *2005 Directors' Deferred Compensation Plan*

The 2005 DDCP was adopted by the 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 Company's Board of Directors 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 2009 LTIP and the 2014 LTIP are administered under this plan.

#### **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 related person transactions and director independence is incorporated herein by reference to the sections captioned "Related Person Transactions," "Director Nominees" and "Director Independence" under "Corporate Governance and Board Matters" in the Company's definitive proxy statement relating to the 2021 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, 2020.

#### **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 "Audit Matters" in the Company's definitive proxy statement relating to the 2021 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, 2020.

## PART IV

### Item 15. Exhibits and Financial Statements Schedules

		<b>Page Reference</b>
<b>(a) 1 Financial Statements</b>		
	Statements of Consolidated Operations for each of the three years in the period ended December 31, 2020	<a href="#">67</a>
	Statements of Consolidated Comprehensive Income for each of the three years in the period ended December 31, 2020	<a href="#">68</a>
	Consolidated Balance Sheets as of December 31, 2020 and 2019	<a href="#">69</a>
	Statements of Consolidated Cash Flows for each of the three years in the period ended December 31, 2020	<a href="#">70</a>
	Statements of Consolidated Equity for each of the three years in the period ended December 31, 2020	<a href="#">71</a>
	Notes to Consolidated Financial Statements	<a href="#">72</a>
<b>2 Financial Statements Schedule</b>		
	Schedule II - Valuation and Qualifying Accounts and Reserves for the Three Years Ended December 31, 2020	

### EQT CORPORATION AND SUBSIDIARIES SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES FOR THE THREE YEARS ENDED DECEMBER 31, 2020

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)				
<b>Valuation allowance for deferred tax assets:</b>				
2020	\$ 423,444	\$ 132,386	\$ —	\$ (25,838)
2019	351,408	84,260	1,114	(13,338)
2018	262,392	98,311	—	(9,295)

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.

### 3 Exhibits

Exhibits	Description	Method of Filing
<a href="#">2.01</a>	Shareholder and Registration Rights Agreement, dated November 12, 2018, between EQT Corporation and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on November 13, 2018.
<a href="#">2.02</a>	Tax Matters Agreement, dated November 12, 2018, between EQT Corporation and Equitrans Midstream Corporation.	Incorporated herein by reference to Exhibit 2.3 to Form 8-K (#001-3551) filed on November 13, 2018.
<a href="#">3.01(a)</a>	Restated Articles of Incorporation of EQT Corporation (as amended through November 13, 2017).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on November 14, 2017.
<a href="#">3.01(b)</a>	Articles of Amendment to the Restated Articles of Incorporation of EQT Corporation (effective May 1, 2020).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on May 4, 2020.

<a href="#">3.01(c)</a>	Articles of Amendment to the Restated Articles of Incorporation of EQT Corporation (effective July 23, 2020).	Incorporated herein by reference to Exhibit 3.1 to Form 8-K (#001-3551) filed on July 23, 2020.
<a href="#">3.02</a>	Amended and Restated Bylaws of EQT Corporation (as amended through May 1, 2020).	Incorporated herein by reference to Exhibit 3.4 to Form 8-K (#001-3551) filed on May 4, 2020.
<a href="#">4.01</a>	Description of Capital Stock.	Incorporated herein by reference to Exhibit 99.1 to Form 8-K (#001-3551) filed on July 15, 2019.
<a href="#">4.02(a)</a>	Indenture, dated April 1, 1983, between EQT Corporation (as successor to Equitable Gas 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.
<a href="#">4.02(b)</a>	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.
<a href="#">4.02(c)</a>	Supplemental Indenture, dated March 15, 1991, between EQT Corporation (as successor to Equitable Resources, Inc.) and Bankers Trust Company.	Incorporated herein by reference to Exhibit 4.01(f) to Form 10-K (#001-3551) for the year ended December 31, 1996.
<a href="#">4.02(d)</a>	Resolutions adopted August 19, 1991 by the Ad Hoc Finance Committee of the Board of Directors of Equitable Resources, Inc. 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.
<a href="#">4.02(e)</a>	Resolutions adopted July 6, 1992 and February 19, 1993 by the Ad Hoc Finance Committee of the Board of Directors of Equitable Resources, Inc. 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.
<a href="#">4.02(f)</a>	Second Supplemental Indenture, dated June 30, 2008, between EQT Corporation, Equitable Resources, Inc., and Deutsche Bank Trust Company Americas, as trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture.	Incorporated herein by reference to Exhibit 4.01(g) to Form 8-K (#001-3551) filed on July 1, 2008.
<a href="#">4.03(a)</a>	Indenture, dated July 1, 1996, between EQT Corporation (as successor to Equitable Resources, Inc.) 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.
<a href="#">4.03(b)</a>	Resolutions adopted January 18 and July 18, 1996 by the Board of Directors of Equitable Resources, Inc. and Resolution adopted July 18, 1996 by the Executive Committee of the Board of Directors of Equitable Resources, Inc., 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.
<a href="#">4.03(c)</a>	First Supplemental Indenture, dated June 30, 2008, between EQT Corporation, Equitable Resources, Inc., and The Bank of New York, as trustee, pursuant to which EQT Corporation 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.
<a href="#">4.04(a)</a>	Indenture, dated March 18, 2008, between EQT Corporation (as successor to Equitable Resources, Inc.) 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.
<a href="#">4.04(b)</a>	Cross-reference table for Indenture dated March 18, 2008 (listed as Exhibit 4.04(a) above) and the Trust Indenture Act of 1939, as amended.	Incorporated herein by reference to Exhibit 4.03(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">4.04(c)</a>	Second Supplemental Indenture, dated June 30, 2008, between EQT Corporation, Equitable Resources, Inc. and The Bank of New York, as trustee, pursuant to which EQT Corporation assumed the obligations of Equitable Resources, Inc. under the related Indenture.	Incorporated herein by reference to Exhibit 4.03(c) to Form 8-K (#001-3551) filed on July 1, 2008.
<a href="#">4.04(d)</a>	Fourth Supplemental Indenture, dated November 7, 2011, between EQT Corporation 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.
<a href="#">4.04(e)</a>	Fifth Supplemental Indenture, dated October 4, 2017, between EQT Corporation 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.

<a href="#">4.04(f)</a>	Sixth Supplemental Indenture, dated October 4, 2017, between EQT Corporation 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.
<a href="#">4.04(g)</a>	Seventh Supplemental Indenture, dated October 4, 2017, between EQT Corporation 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.
<a href="#">4.04(h)</a>	Eighth Supplemental Indenture, dated October 4, 2017, between EQT Corporation 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.
<a href="#">4.04(i)</a>	Ninth Supplemental Indenture, dated January 21, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 6.125% Senior Notes due 2025 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on January 21, 2020.
<a href="#">4.04(j)</a>	Tenth Supplemental Indenture, dated January 21, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 7.000% Senior Notes due 2030 were issued.	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on January 21, 2020.
<a href="#">4.04(k)</a>	Eleventh Supplemental Indenture, dated November 16, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 5.00% Senior Notes due 2029 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on November 16, 2020.
<a href="#">4.05</a>	Indenture, dated April 28, 2020, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 1.75% Convertible Senior Notes due 2026 were issued.	Incorporated herein by reference to Exhibit 4.1 to Form 8-K (#001-3551) filed on April 29, 2020.
<a href="#">10.01</a>	Second Amended and Restated Credit Agreement, dated of July 31, 2017, among EQT Corporation, 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.
<a href="#">10.02</a>	Term Loan Agreement, dated May 31, 2019, among EQT Corporation, PNC Bank, National Association, as administrative agent, and the other lenders party thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 31, 2019.
<a href="#">10.03(a)</a>	Gas Gathering and Compression Agreement, dated February 26, 2020, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q (#001-3551) for the quarter ended March 31, 2020.
<a href="#">10.03(b)</a>	First Amendment to Gas Gathering and Compression Agreement, dated August 26, 2020, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q (#001-3551) for the quarter ended September 30, 2020.
<a href="#">10.03(c)</a>	Letter Agreement, dated November 1, 2020, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Filed herewith as Exhibit 10.03(c).
<a href="#">10.04(a)</a>	Purchase Agreement, dated April 23, 2020, among EQT Corporation and J.P. Morgan Securities LLC, Barclays Capital Inc. and Credit Suisse Securities (USA) LLC, as representative of the several initial purchasers of the 1.75% Convertible Senior Notes due 2026 named in Schedule 1 attached thereto.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on April 29, 2020.
<a href="#">10.04(b)</a>	Form of Capped Call Confirmation.	Incorporated herein by reference to Exhibit 10.2 to Form 8-K (#001-3551) filed on April 29, 2020.
<a href="#">*10.05(a)</a>	EQT Corporation 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.
<a href="#">*10.05(b)</a>	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.
<a href="#">*10.05(c)</a>	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.
<a href="#">*10.05(d)</a>	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.

<a href="#">*10.05(e)</a>	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.
<a href="#">*10.05(f)</a>	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.
<a href="#">*10.05(g)</a>	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.
<a href="#">*10.05(h)</a>	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.
<a href="#">*10.06(a)</a>	EQT Corporation 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 1, 2014.
<a href="#">*10.06(b)</a>	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.
<a href="#">10.06(c)</a>	Form of Restricted Stock Unit Award Agreement (Standard) under 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.02(o) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">10.06(d)</a>	Form of 2018 Value Driver Performance Award Agreement.	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">10.06(e)</a>	Form of 2018 Restricted Stock Units Award Agreement (Standard) under 2014 Long-Term Incentive Plan (2018 grants).	Incorporated herein by reference to Exhibit 10.02(t) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">10.06(f)</a>	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.
<a href="#">10.06(g)</a>	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.
<a href="#">10.06(h)</a>	Form of Participant Award Agreement under 2018 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(w) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">10.06(i)</a>	Form of 2018 Restricted Stock Unit Award Agreement (Transaction).	Incorporated herein by reference to Exhibit 10.02(y) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">*10.06(j)</a>	Form of Participant Award Agreement (Stock Option) under 2014 Long-Term Incentive Plan (2019 grants).	Incorporated herein by reference to Exhibit 10.02(z) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">*10.06(k)</a>	Form of Restricted Stock Award Agreement (Standard) under 2014 Long-Term Incentive Plan (2019 grants).	Incorporated herein by reference to Exhibit 10.02(aa) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">*10.06(l)</a>	2019 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(bb) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">*10.06(m)</a>	Form of Participant Award Agreement under 2019 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.02(cc) to Form 10-K (#001-3551) for the year ended December 31, 2018.
<a href="#">*10.07</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.
<a href="#">*10.08(a)</a>	EQT Corporation 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 99.1 to Form S-8 (#001-3551) filed on July 15, 2019.
<a href="#">*10.08(b)</a>	Form of Restricted Stock Unit Award Agreement (Standard) under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(c) to Form 10-K (#001-3551) for the year ended December 31, 2019.

<a href="#">*10.08(c)</a>	Form of Incentive Performance Share Unit Program under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(d) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.08(d)</a>	Form of Participant Award Agreement under 2020 Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.06(e) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.08(e)</a>	Form of Stock Appreciation Rights Award Agreement under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(f) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.09</a>	EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 99.1 to Form S-8 (#333-237953) filed on May 1, 2020.
<a href="#">*10.10(a)</a>	Form of Restricted Stock Unit Award Agreement (Standard).	Filed herewith as 10.10(a).
<a href="#">*10.10(b)</a>	Form of Restricted Stock Unit Award Agreement (Non-Employee Directors).	Incorporated herein by reference to Exhibit 10.06(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.11</a>	Form of EQT Corporation Short-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 4, 2020.
<a href="#">*10.12(a)</a>	Form of Incentive Performance Share Unit Program.	Filed herewith as 10.12(a).
<a href="#">*10.12(b)</a>	Form of Participant Award Agreement under Incentive Performance Share Unit Program.	Filed herewith as 10.12(b).
<a href="#">*10.13</a>	Form of Participant Award Agreement (Stock Option).	Incorporated herein by reference to Exhibit 10.06(g) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.14</a>	EQT Corporation Executive Severance Plan and Form of Participation Notice.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on May 20, 2020.
<a href="#">*10.15</a>	EQT Corporation Employee Savings Plan.	Incorporated herein by reference to Exhibit 4.1 to Form S-8 (#333-230970) filed on April 22, 2019.
<a href="#">*10.16</a>	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.
<a href="#">*10.17(a)</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.
<a href="#">*10.17(b)</a>	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.
<a href="#">*10.18(a)</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.
<a href="#">*10.18(b)</a>	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.
<a href="#">*10.19(a)</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.
<a href="#">*10.19(b)</a>	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.
<a href="#">*10.20</a>	Form of Indemnification Agreement between EQT Corporation and executive officers and outside directors.	Incorporated herein by reference to Exhibit 10.18 to Form 10-K (#001-3551) for the year ended December 31, 2008.
<a href="#">*10.21</a>	Separation and Release Agreement, dated November 13, 2017, among EQT Corporation, 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.

<a href="#">*10.22(a)</a>	Offer Letter, dated January 13, 2020, between EQT Corporation and Kyle Derham.	Incorporated herein by reference to Exhibit 10.27(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.22(b)</a>	Services Agreement, dated January 13, 2020, between EQT Corporation and Kyle Derham.	Incorporated herein by reference to Exhibit 10.27(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.23(a)</a>	Offer Letter, dated December 18, 2019, between EQT Corporation and David M. Khani.	Incorporated herein by reference to Exhibit 10.28(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.23(b)</a>	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated January 3, 2020, between EQT Corporation and David M. Khani.	Incorporated herein by reference to Exhibit 10.28(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.24(a)</a>	Offer Letter, dated January 6, 2020, between EQT Corporation and William E. Jordan.	Incorporated herein by reference to Exhibit 10.29(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.24(b)</a>	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated January 6, 2020, between EQT Corporation and William E. Jordan.	Incorporated herein by reference to Exhibit 10.29(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.25(a)</a>	Offer Letter, dated July 18, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.25(b)</a>	Confidentiality, Non-Solicitation and Non-Competition Agreement, dated August 5, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(b) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.25(c)</a>	Relocation Expense Reimbursement Agreement, dated July 24, 2019, between EQT Corporation and Richard Anthony Duran.	Incorporated herein by reference to Exhibit 10.30(c) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">*10.26</a>	Offer Letter, dated July 16, 2019, between EQT Corporation and Lesley Evancho.	Incorporated herein by reference to Exhibit 10.31(a) to Form 10-K (#001-3551) for the year ended December 31, 2019.
<a href="#">21</a>	Schedule of Subsidiaries.	Filed herewith as Exhibit 21.
<a href="#">23.01</a>	Consent of Independent Registered Public Accounting Firm.	Filed herewith as Exhibit 23.01.
<a href="#">23.02</a>	Consent of Netherland, Sewell & Associates, Inc.	Filed herewith as Exhibit 23.02.
<a href="#">31.01</a>	Rule 13(a)-14(a) Certification of Principal Executive Officer.	Filed herewith as Exhibit 31.01.
<a href="#">31.02</a>	Rule 13(a)-14(a) Certification of Principal Financial Officer.	Filed herewith as Exhibit 31.02.
<a href="#">32</a>	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer.	Furnished herewith as Exhibit 32.
<a href="#">99</a>	Independent Petroleum Engineers' Audit Report.	Filed herewith as Exhibit 99.
101	Interactive Data File.	Filed herewith as Exhibit 101.
104	Cover Page Interactive Data File.	Formatted as Inline XBRL and contained in Exhibit 101.

*Each management contract and compensatory arrangement in which any director or any named executive officer participates has been marked with an asterisk (\*)*

We agree to furnish to the SEC, upon request, copies of instruments with respect to long-term debt that have not previously been filed.

**Item 16.** Form 10-K Summary

None.

**SIGNATURES**

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

**EQT CORPORATION**

By:

/s/ Toby Z. Rice

Toby Z. Rice  
President and Chief Executive Officer  
February 17, 2021

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/ TOBY Z. RICE _____ Toby Z. Rice (Principal Executive Officer)	President, Chief Executive Officer and Director	February 17, 2021
/s/ DAVID M. KHANI _____ David M. Khani (Principal Financial Officer)	Chief Financial Officer	February 17, 2021
/s/ TODD M. JAMES _____ Todd M. James (Principal Accounting Officer)	Chief Accounting Officer	February 17, 2021
/s/ LYDIA I. BEEBE _____ Lydia I. Beebe	Chair	February 17, 2021
/s/ PHILIP G. BEHRMAN _____ Philip G. Behrman	Director	February 17, 2021
/s/ LEE M. CANAAN _____ Lee M. Canaan	Director	February 17, 2021
/s/ JANET L. CARRIG _____ Janet L. Carrig	Director	February 17, 2021
/s/ KATHRYN J. JACKSON _____ Kathryn J. Jackson	Director	February 17, 2021
/s/ JOHN F. MCCARTNEY _____ John F. McCartney	Director	February 17, 2021
/s/ JAMES T. MCMANUS II _____ James T. McManus II	Director	February 17, 2021
/s/ ANITA M. POWERS _____ Anita M. Powers	Director	February 17, 2021
/s/ DANIEL J. RICE IV _____ Daniel J. Rice IV	Director	February 17, 2021
/s/ STEPHEN A. THORINGTON _____ Stephen A. Thorington	Director	February 17, 2021
/s/ HALLIE A. VANDERHIDER _____ Hallie A. Vanderhider	Director	February 17, 2021



**SPECIFIC TERMS IN THIS EXHIBIT HAVE BEEN REDACTED BECAUSE SUCH TERMS ARE BOTH NOT MATERIAL AND WOULD LIKELY CAUSE COMPETITIVE HARM TO EQT CORPORATION IF PUBLICLY DISCLOSED. THESE REDACTED TERMS HAVE BEEN MARKED IN THIS EXHIBIT AT THE APPROPRIATE PLACE WITH THREE ASTERISKS [\*\*\*].**

November 1, 2020

Rice Drilling B LLC  
625 Liberty Avenue, Suite 1700  
Pittsburgh, Pa 15222-3111  
Attn: Ray Franks

RE: Heyl Well Pad

Dear Mr. Franks:

Reference is made to that certain Gas Gathering and Compression Agreement dated as of February 26, 2020 by and among EQT Corporation, EQT Production Company, Rice Drilling B LLC, and EQT Energy, LLC (collectively, “**Producer**”), and EQM Gathering Opco, LLC (“**Gatherer**”), as the same was amended by that certain First Amendment to Gas Gathering and Compression Agreement dated August 26, 2020, between Producer and Gatherer (as amended, the “**Gathering Agreement**”). All capitalized terms used but not otherwise defined in this letter agreement (“**Letter Agreement**”) shall have the meanings (if any) ascribed to them in the Gathering Agreement.

WHEREAS, the Well Pad of Producer located in Washington County, PA within the Applicable Area on TPN: 020-028-00-00-002-01 and known as the Heyl Well Pad (“**Heyl Well Pad**”) has an Anticipated Production Date of [\*\*\*];

WHEREAS, the Connection Notice Information for the Additional Receipt Point at the Heyl Well Pad contemplates that such Additional Receipt Point meets the Additional Connection Criteria and, pursuant and subject to the terms of the Gathering Agreement, Gatherer is obligated to connect such Additional Receipt Point to the Gathering System at the Heyl Well Pad at Gatherer’s sole cost and expense, including with respect to the acquisition of all rights of way; and

WHEREAS, Producer is willing to deliver Dedicated Gas produced from the Heyl Well Pad to the point of interconnection (“**Mako Interconnect**”) with Gatherer’s NIMAD001 pipeline (the “**Mako Line**”) as depicted on Exhibit A attached hereto (the “**Heyl Receipt Point**”) rather than at the Heyl Well Pad.

WHEREAS, the Parties wish to add a new Delivery Point in the Mercury System AMI at Gatherer’s sole cost and expense, as detailed herein.

---

NOW, THEREFORE, Gatherer and Producer (collectively, “**Parties**” and each a “**Party**”), by execution of this Letter Agreement and in consideration of the mutual covenants contained herein, do hereby agree as follows:

1. ***Connection of Well Line to Heyl Receipt Point.***

(a) Gatherer, at its own expense, covenants and agrees to install and place into service the equipment and appurtenant facilities required at the Mako Interconnect for the Heyl Receipt Point on or before the later of (i) [\*\*\*] and (ii) [\*\*\*] (“**Heyl Completion Date**”), consistent with the responsibility matrix set forth on Exhibit B (“**Responsibility Matrix**”).

(b) Gatherer, at its own expense, covenants and agrees to install the related dehydration facilities and Measurement Facilities on the Heyl Well Pad on or before the Heyl Completion Date and thereafter own, operate and maintain such facilities; provided, however, Producer has agreed to provide Gatherer with sufficient space on the Heyl Well Pad for such facilities.

(c) Producer, at its own expense, covenants and agrees to construct and install a well line that is at least [\*\*\*] inches in diameter with a MAOP of [\*\*\*] psig (“**Well Line**”) extending from the Heyl Well Pad Measurement Facilities to the Heyl Receipt Point, at which point Gatherer shall receive Dedicated Gas into the Gathering System for delivery under and subject to the Gathering Agreement. Producer shall connect the Well Line to the Mako Line at the Mako Interconnect on or before [\*\*\*], consistent with the Responsibility Matrix, provided, however, that Gatherer’s sole remedy for Producer’s failure to construct the Well Line shall be the delay of the Heyl Completion Date, as described in Section 1(a) hereof. Producer shall thereafter own, operate and maintain the Well Line at its own expense and shall be responsible for all line losses attributable to the Well Line.

(d) Producer hereby agrees, to the extent that it may do so contractually and lawfully (excluding contractual, legal or other rights granted to Producer pursuant to oil, gas or mineral lease), to grant and convey to Gatherer an easement and right of way, including without limitation, the right of ingress and egress to and from the Heyl Well Pad along the route depicted on Exhibit A, for the purpose of installing, maintaining, inspecting, operating, replacing, disconnecting and removing the dehydration facilities and Measurement Facilities on the Heyl Well Pad and the Well Line.

(e) Gatherer agrees, to the extent that it may do so contractually and lawfully, to grant and convey to Producer necessary easement and right of way and any permits to aid in Producer’s installation of the Well Line.

(f) Notwithstanding anything herein to the contrary, this Letter Agreement shall not alter or affect Producer’s remedies under the Gathering Agreement for Gatherer’s failure to provide service at the Heyl Receipt Point in accordance with the terms thereof, provided, however, that, for the limited purposes of the Heyl Receipt Point, the term Completion Deadline shall, as it applies thereto, mean the Heyl Completion Date.

2. ***Transition to Low Pressure; Incremental Compression.***

(a) Gatherer, at its own expense, covenants and agrees to construct and install a well line at the location depicted on Exhibit C of approximately [\*\*\*] feet in length and at least [\*\*\*] inches in diameter with a MAOP of at least [\*\*\*] psig (“***Jupiter Line***”) connecting the Heyl Well Pad to the Gathering System at a new receipt valve near the Mako Interconnect and flowing to the Jupiter and BJ System AMI within [\*\*\*] months of the Heyl Completion Date (such date of completion being the “***Jupiter Line Completion Date***”). Such new receipt valve shall thereafter become the Heyl Receipt Point and Gatherer reserves right to remove the original Heyl Receipt Point at the Mako Interconnect.

(b) Upon the Jupiter Line Completion Date, (i) the Heyl System AMI shall be eliminated and the Heyl Receipt Point shall become a part of the Jupiter and BJ System AMI, (ii) the Heyl Receipt Point shall be transitioned from High Pressure to Low Pressure, (iii) the dehydration facilities located on the Heyl Well Pad shall be removed, and (iv) Incremental Compression shall be reduced by [\*\*\*] HP.

(c) Pursuant to (and not, for the avoidance of doubt, in addition to) Section 5.1(d) of the Gathering Agreement, Dedicated Gas received into the Gathering System from the Heyl Receipt Point after the Jupiter Line Completion Date shall be subject to an Incremental Compression Fee equal to the product of (A) the aggregate quantity of Gas serviced from Incremental Compression, stated in Dth, received from Producer or for Producer’s account (including Dedicated Gas produced by any Affiliate) during such Month at the Heyl Receipt Point multiplied by (B) the number of stages of compression utilized with such Incremental Compression multiplied by (C) the applicable amounts set forth in Exhibit H to the Gathering Agreement; provided, however the Parties hereby agree that the stages of compression utilized for the purpose of clause (B) shall be [\*\*\*] stage of compression if the average Low Pressure Receipt Point Pressure is greater than or equal to [\*\*\*] psig and two (2) stages of compression if the average Low Pressure Receipt Point Pressure is less than [\*\*\*] psig; and provided, further, Producer shall be credited an amount of [\*\*\*] Dollars (\$[\*\*\*]) against any Incremental Compression Fees thereafter accrued, in the aggregate, with respect to Dedicated Gas received by Gatherer at the Heyl Receipt Point.

(d) In the event that the Jupiter Line Completion Date does not occur by the date that is [\*\*\*] months following the Heyl Completion Date, Producer shall be credited an amount of [\*\*\*] Dollars (\$[\*\*\*]) against any fees (including Reservation Fees, Overrun Fees, Pipeline Drip Handling Fees, and Incremental Compression Fees) thereafter accrued, in the aggregate, under the Gathering Agreement.

3. ***Mercury System AMI Additional Delivery Point.*** The Parties agree that Exhibit C to the Gathering Agreement shall hereby be amended to include an additional Delivery Point (the “Eureka Smithfield Delivery Point”) in the Mercury AMI, as set forth on Exhibit D. The Eureka Smithfield Delivery Point shall be connected to Eureka Midstream LLC’s Smithfield gathering pipeline and shall provide Services to each of the Receipt Points connected upstream of the Stingray WG100 Delivery Point. Gatherer shall connect the Eureka Smithfield Delivery Point to the Gathering System at Gatherer’s sole cost and expense. Parties agree the MRDO for the Eureka Smithfield Delivery Point shall be [\*\*\*] Mcfd and all Services to such Delivery Point

shall be Interruptible Service. The Parties acknowledge that all Gas tendered to the Receipt Points upstream of the Stingray WG100 Delivery Point shall flow either (a) entirely to the existing Stingray WG100 Delivery Point or (b) entirely to the Eureka Smithfield Delivery Point, and in no event shall proportional flow to each Delivery Point be permitted.

4. **Miscellaneous.** The terms and provisions of this Letter Agreement shall be binding on, and shall inure to the benefit of, the Parties and their respective successors and permitted assigns. This Letter Agreement may be executed in any number of counterparts, and each such counterpart hereof shall be deemed to be an original instrument, but all of such counterparts shall constitute for all purposes one agreement. Any signature hereto delivered by a Party by facsimile or other electronic transmission (including scanned documents delivered by email) shall be deemed an original signature hereto, and execution and delivery by such means shall be binding upon the Parties.

5. **Effect of Letter Agreement.** The Parties acknowledge and agree that this Letter Agreement constitutes a written instrument executed by the Parties and fulfills the requirements of an amendment contemplated by Section 18.7 of the Gathering Agreement. The Parties hereby ratify and confirm the Gathering Agreement, as amended hereby. Except as expressly provided herein, the provisions of the Gathering Agreement shall remain in full force and effect in accordance with their respective terms following the execution of this Letter Agreement. In the event of any conflict or inconsistencies between this Letter Agreement and the Gathering Agreement, the terms and conditions of this Letter Agreement shall prevail.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF, the Parties have executed this Letter Agreement as of the date first written above

**GATHERER:**

**EQM GATHERING OPCO, LLC,**  
a Delaware limited liability company

By: /s/ Paul Kress  
Name: Paul Kress  
Title: Vice President, Business Development

**PRODUCER:**

**EQT CORPORATION,**  
a Pennsylvania corporation

By: /s/ Toby Rice  
Name: Toby Rice  
Title: President & CEO

**EQT PRODUCTION COMPANY,**  
a Pennsylvania corporation

By: /s/ Toby Rice  
Name: Toby Rice  
Title: President & CEO

**RICE DRILLING B LLC,**  
a Delaware limited liability company

By: /s/ Toby Rice  
Name: Toby Rice  
Title: President & CEO

**EQT ENERGY, LLC,**  
a Delaware limited liability company

By: /s/ Keith Shoemaker  
Name: Keith Shoemaker  
Title: SVP Commercial

Exhibit A

\*\*\*

## Exhibit B

[\*\*\*]

Company (Gatherer) Owned Measurement						
Responsibility for Receipt Point Interconnect Facility Equipment into Equitrans Midstream Gathering Systems						
Customer Name - Interconnect Name						
STATION EQUIPMENT	REQUIRED	DESIGN SPECIFICATIONS	INSTALL	OWNERSHIP	OPERATE	MAINTAIN
<b>PIPING</b>						
Inlet Piping	Yes	Customer	Customer	Customer	Customer	Customer
Corrosion Protection - Inlet Piping	Yes	Customer	Customer	Customer	Customer	Customer
Station & Outlet Piping	Yes	Company	Company	Company	Company	Company
Corrosion Protection - Station & Outlet Piping	Yes	Company	Company	Company	Company	Company
Company Pipeline Tap & Valve	Yes	Company	Company	Company	Company	Company
Corrosion Protection - Company Tap & Valve	Yes	Company	Company	Company	Company	Company
<b>GAS CONDITIONING</b>						
Filter Separator	No					
Particulate Filter	No					
Liquid Level Strutoff	No					
<b>MEASUREMENT</b>						
Meter & Meter Runs	Yes	Company	Company	Company	Company	Company
Meter & Flow Control Risers, Valves, etc.	Yes	Company	Company	Company	Company	Company
Electronic Measurement & Telecomm Hardware	Yes	Company	Company	Company	Company	Company
<b>GAS QUALITY</b>						
Chromatograph	No					
Moisture Analyzer*	No					
Oxygen Analyzer	No					
Hydrogen Sulfide Analyzer	No					
<b>PRESSURE / FLOW CONTROL</b>						
Overpressure Protection Device	Yes	Company	Company	Company	Company	Company
Primary Pressure Control	No					
Flow Control	No					
Isolation Valve	Yes	Company	Company	Company	Company	Company
Header	No					
Check Valve	Yes	Company	Company	Company	Company	Company
<b>ODORIZATION</b>						
Odorizer & Controls	No					
<b>MISCELLANEOUS</b>						
Land and Access Road	Yes	Customer	Customer	Customer	Customer	Customer
Site Grading, Pad, and Access Road Construction	Yes	Customer	Customer	Customer	Customer	Customer
Communication Service(s)	Yes	Company	Company	Company	Company	Company
Electrical Service**	Yes	Company	Company	Company	Company	Company
Building - Gas Chromatograph	No					
Building / Enclosure - Odorizer	No					
Fence/Vehicle Barrier/Signage	Yes	Company	Customer	Customer	Company	Customer

\*Company may request moisture data hand-off from Customer Delay

\*\*Customer to provide electric drop to Company at no cost if available on pad

Exhibit C

[\*\*]

Exhibit D

[\*\*\*]

SYSTEM AMI	Gas Type	Initial MDQ (Mcf)	Maximum MDQ (Mcf)	System Compressor Station	System Compression Station GPS	LP MDQ (Mcf)	Suction Pressure (psig)	LUF Target %	Fuel Target %	MAOP	Avg Allowable Operating Pressure (psig)	Delivery Points	Delivery Point GPS	FTS Credit Delivery Point	Initial MRDO (Mcf) <sup>2</sup>	Maximum MRDO (Mcf)
MERCURY	[***]	[***]	[***]	[***]	[***]	[***]	[***]	[***]	[***]	[***]	[***]	[***]	[***]			[***]

**EQT CORPORATION**  
**RESTRICTED STOCK UNIT AWARD AGREEMENT (STANDARD)**

*Non-transferable*

**G R A N T T O**

\_\_\_\_\_  
 (“Participant”)

**DATE OF GRANT:** \_\_\_\_\_  
 (“Grant Date”)

by EQT Corporation (the “Company”) of [\_\_\_\_\_] restricted stock units, which vest and convert into the right to receive an equivalent number of shares of the Company’s common stock (the “Common Stock”), pursuant to and subject to the provisions of the EQT Corporation [\_\_\_\_\_] Long-Term Incentive Plan (as amended from time to time, the “Plan”), and the terms and conditions set forth in this award agreement (this “Agreement”).

The restricted stock units awarded under this Agreement shall not be effective unless, no later than 45 days after the Grant Date, Participant accepts the restricted stock units through the Fidelity NetBenefits website, which can be found at [www.netbenefits.fidelity.com](http://www.netbenefits.fidelity.com).

When Participant accepts the restricted stock units awarded under this Agreement through the Fidelity NetBenefits website, Participant shall be deemed to have (i) acknowledged receipt of the restricted stock units granted on the Grant Date (the terms of which are subject to the terms and conditions of this Agreement and the Plan) and copies of this Agreement and the Plan and (ii) agreed to be bound by all the provisions of this Agreement and the Plan.

**TERMS AND CONDITIONS**

1. Defined Terms. Capitalized terms used herein and not otherwise defined shall have the meanings assigned to such terms in the Plan. In addition, and notwithstanding any contrary definition in the Plan, for purposes of this Agreement:

(a) “Employer” is defined in Section 8 of this Agreement.

(b) “Executive Severance Plan” means that certain EQT Corporation Executive Severance Plan established effective May 19, 2020, as may be amended from time to time. For the avoidance of doubt, reference to a severance or similar agreement in the Plan includes the Executive Severance Plan with respect to any Executive Severance Plan Participant.

(c) “Executive Severance Plan Participant” means an individual who is, at the relevant time, a Participant under the Executive Severance Plan (with the definition of “Participant” for this purpose being set forth in the Article II of the Executive Severance Plan).

(d) “Payment Date” is defined in Section 4 of this Agreement.

(e) “Qualifying Change of Control” means a Change of Control (as then defined in the Plan) unless (i) Participant’s Restricted Stock Units are assumed by the surviving entity of the Change of Control (or otherwise equitably converted or substituted in connection with the Change of Control in a manner approved by the Committee) or (ii) the Company is the surviving entity of the Change of Control.

(f) “Restricted Stock Units” means collectively, the original number of restricted stock units awarded to Participant on the Grant Date as designated in the first paragraph of this Agreement (subject to such adjustments, if any, set forth in the Plan and this Agreement) together with any additional restricted stock units accumulated from dividend equivalents in accordance with Section 5 of this Agreement.

(g) “Vesting Date” is defined in Section 2(a) of this Agreement.

2. Vesting of Restricted Stock Units. The Restricted Stock Units have been credited to a bookkeeping account on behalf of Participant and do not represent actual shares of Common Stock. Participant shall have no right to exchange the Restricted Stock Units for cash, stock or any other benefit and shall be a mere unsecured creditor of the Company with respect to such Restricted Stock Units and any future rights to benefits.

(a) General. Except as may be otherwise provided below or under (i) any written employment-related agreement with Participant (including any confidentiality, non-solicitation, non-competition, change of control or similar agreement), if any, or (ii) if Participant is an Executive Severance Plan Participant, the Executive Severance Plan, as provided therein with respect to such Participant, and subject to the provisions of Sections 2(b) and 3 hereof, the Restricted Stock Units will vest and become non-forfeitable as to [ ] of the shares of Common Stock subject to the Restricted Stock Units on each [ ] anniversaries of the Grant Date (each, a “Vesting Date”), provided that Participant has continued in the employment of the Company and/or its Affiliates through each such date.

(b) Qualifying Change of Control Vesting. 100% of the Restricted Stock Units will vest upon the occurrence of a Qualifying Change of Control, provided that Participant has continued in the employment of the Company and/or its Affiliates through such date.

3. Change in Status.

(a) In the event of a Change of Control that is not a Qualifying Change of Control, as a condition to the vesting of any Restricted Stock Units pursuant to Section [ ] of the Plan, Participant will be required to timely execute and not revoke within any time provided to do so a full release of claims in a form acceptable to the Company within 30 days of the termination. Failure to satisfy this condition will result in forfeiture of such unvested Restricted Stock Units.

(b) If Participant’s employment is terminated due to Participant’s death, 100% of the unvested Restricted Stock Units will vest. As a condition to the vesting of any Restricted Stock Units pursuant to this Section 3(b), Participant’s estate or beneficiary will be required to timely execute and not revoke within any time provided to do so a full release of claims in a form

acceptable to the Company within 60 days of Participant's death. Failure to satisfy this condition will result in forfeiture of such unvested Restricted Stock Units.

(c) Except as may be otherwise provided under (i) any written employment-related agreement with Participant, if any, or (ii) if Participant is an Executive Severance Plan Participant, in the Executive Severance Plan, as provided therein with respect to such Participant, in the event Participant's employment terminates for any other reason, all of Participant's unvested Restricted Stock Units will immediately be forfeited without further consideration or any act or action by Participant. Notwithstanding anything to the contrary in this Section 3, if Participant's employment is terminated voluntarily or such termination is an involuntary termination by the Company without Cause and, in each case, Participant remains on the board of directors of the Company or an Affiliate whose equity is publicly traded on the New York Stock Exchange or the NASDAQ Stock Market following such termination of employment, Participant's Restricted Stock Units shall not be forfeited but shall continue to vest in accordance with the above provisions for as long as Participant remains on such board of directors, in which case any references herein to Participant's employment shall be deemed to include his or her continued service on such board.

4. Form and Time of Payment. The Restricted Stock Units shall be payable (i) on the applicable payment date (each, a "Payment Date") as provided in this Section 4, and (ii) paid in a number of shares of Common Stock equal to one share of Common Stock times the number of Restricted Stock Units then vesting. The value of shares of Common Stock shall not bear any interest owing to the passage of time. Neither this Section 4 nor any action taken pursuant to or in accordance with this Agreement shall be construed to create a trust or a funded or secured obligation of any kind.

(a) The Payment Date for Restricted Stock Units vesting pursuant to Section 2(a) shall be a date selected by the Company that is no later than thirty (30) calendar days after the applicable Vesting Date.

(b) The Payment Date for Restricted Stock Units vesting pursuant to Section 2(b) shall be the closing date of the Qualifying Change of Control.

(c) The Payment Date for Restricted Stock Units vesting pursuant to Section 3(a) shall be a date selected by the Company that is no later than sixty (60) days after the termination of Participant's employment, provided that any release of claims required under Section 3(a) has become effective.

(d) The Payment Date for Restricted Stock Units vesting pursuant to Section 3(b) shall be a date selected by the Company that is no later than 60 days after the date of Participant's death, provided that the any release of claims required under Section 3(b) has become effective, and provided further, that if such 60-day period begins in once calendar year and ends in the next calendar year, the payment shall in all events be made in the second such calendar year.

(e) Such other date as may be otherwise provided under any written employment-related agreement with Participant (including any confidentiality, non-solicitation,

non-competition, change of control or similar agreement) or, if Participant is an Executive Severance Plan Participant, in the Executive Severance Plan, as provided therein with respect to such Participant.

5. Dividend Equivalents. If the Restricted Stock Units are outstanding on the record date for dividends or other distributions with respect to the Common Stock, then the dollar amount or Fair Market Value of such dividends or distributions with respect to the number of shares of Common Stock then underlying the Restricted Stock Units shall be converted into additional Restricted Stock Units in Participant's name, based on the Fair Market Value of the Common Stock as of the date such dividends or distributions are paid (rounded down to the nearest whole Restricted Stock Unit), with any fractional Restricted Stock Units converted into a right to receive an equivalent amount in cash. Any additional Restricted Stock Units or cash pursuant to this Section 5 shall vest at the same time and in the same manner as the Restricted Stock Units to which they are attributable vest, and will be paid to Participant in accordance with the Payment Dates set forth in Section 4 above. Any additional Restricted Stock Units pursuant to this Section 5 shall also be subject to the transfer restrictions as apply to the Restricted Stock Units with respect to which they relate.

6. Restrictions on Transfer and Pledge. No right or interest of Participant in the Restricted Stock Units may be pledged, encumbered or hypothecated or be made subject to any lien, obligation or liability of Participant to any other party other than the Company or an Affiliate. Except as provided in the Plan, the Restricted Stock Units may not be sold, assigned, transferred or otherwise disposed of by Participant other than by will or the laws of descent and distribution. The designation of a beneficiary shall not constitute a transfer.

7. Limitation of Rights. The Restricted Stock Units do not confer to Participant or Participant's beneficiary, executors or administrators any rights of a shareholder of the Company. Participant shall not have voting or any other rights as a shareholder of the Company with respect to the Restricted Stock Units.

8. Payment of Taxes. The Company or any Affiliate employing Participant (the "Employer") has the authority and the right to deduct or withhold, or require Participant to remit to the Employer, an amount sufficient to satisfy federal, state and local taxes (including Participant's portion of all payroll tax obligations) required by law to be withheld with respect to any taxable event arising as a result of this award. With respect to withholding required upon any taxable event arising (a) in connection with the Restricted Stock Units, the Employer shall satisfy the tax withholding required by withholding shares of Common Stock from shares otherwise issuable pursuant to this award having a Fair Market Value as of the date that the amount of tax to be withheld is to be determined equal to the amount of tax required to be withheld and (b) in connection with any cash payments pursuant to Section 5, the Employer shall satisfy the tax withholding by deducting the amount of tax required to be withheld from such cash payments. The obligations of the Company under this Agreement will be conditional on such payment or arrangements, and the Company and, where applicable, its Affiliates will, to the extent permitted by law, have the right to deduct any such taxes from any payment of any kind otherwise due to Participant.

9. Plan Controls. This Agreement and Participant's rights hereunder are subject to all the terms and conditions of the Plan and such rules and regulations as the Committee may adopt for administration of the Plan. It is expressly understood that the Committee is authorized to interpret and administer the Plan and this Agreement, and to make all decisions and determinations as it may deem to be necessary or advisable for the administration thereof, all of which shall be final and binding upon Participant and the Company. In the event of any actual or alleged conflict between the provisions of the Plan and the provisions of this Agreement, the provisions of the Plan shall be controlling and determinative. Any conflict between this Agreement, on the one hand, and the terms of a written employment-related agreement with Participant effective on or prior to the Grant Date or, if Participant is an Executive Severance Plan Participant, the Executive Severance Plan, shall be decided in favor of the provisions of such employment-related agreement or the Executive Severance Plan, as applicable.

10. Recoupment Policy. Any shares of Common Stock distributed or amounts paid to Participant hereunder, and any cash or other benefit acquired on the sale of shares of Common Stock distributed hereunder, shall be subject to the terms and conditions of any compensation recoupment policy adopted from time to time by the Company's board of directors or any committee of such board, to the extent such policy is applicable to Participant and the Restricted Stock Units.

11. Relationship to Other Benefits. The Restricted Stock Units shall not affect the calculation of benefits under the Company's or its Affiliates' qualified retirement plans or any other retirement, compensation or benefit plan or program of the Company or its Affiliates, except to the extent specifically provided in such other plan or program. Nothing herein shall prevent the Company or its Affiliates from maintaining additional compensation plans and arrangements.

12. Amendment. Subject to the terms of the Plan, this Agreement may be modified or amended by the Committee; provided that no such amendment shall materially and adversely affect the rights of Participant hereunder without the consent of Participant. Notwithstanding the foregoing, Participant hereby expressly agrees to any amendment to the Plan and this Agreement to the extent necessary to comply with applicable law or changes to applicable law (including, but not limited to, Code Section 409A) and related regulations or other guidance and federal securities laws.

13. Successors and Assigns. The Company may assign any of its rights under this Agreement without Participant's consent. All obligations of the Company under the Plan and this Agreement shall be binding on and inure to the benefit of any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation or otherwise, of all or substantially all of the business and/or assets of the Company. Subject to the restrictions on transfer set forth herein and in the Plan, this Agreement will be binding upon Participant and Participant's beneficiaries, executors, administrators and the person(s) to whom the Restricted Stock Units may be transferred by will or the laws of descent or distribution.

14. Applicable Law. This Agreement shall be governed by and construed under the laws of the Commonwealth of Pennsylvania without regard to its conflict of law provisions.

15. Notice. Except as may be otherwise provided by the Plan or determined by the Committee and communicated to Participant, notices and communications hereunder must be in writing and shall be deemed sufficiently given if either hand-delivered or if sent by fax or overnight courier, or by postage paid first class mail. Notices sent by mail shall be deemed received five business days after mailed, but in no event later than the date of actual receipt. Notices shall be directed, if to Participant, at Participant's address indicated by the Company's records or, if to the Company, at the Company's principal executive office, Attention: Director Total Rewards.

16. Dispute Resolution. Any dispute regarding the payment of benefits under this Agreement or the Plan shall be resolved in accordance with the EQT Corporation Long-Term Incentive Dispute Resolution Procedures as in effect at the time of such dispute. A copy of such procedures is available on the Fidelity NetBenefits website, which can be found at [www.netbenefits.fidelity.com](http://www.netbenefits.fidelity.com).

17. Tax Consequences to Participant. It is intended that, (a) until the applicable Vesting Date occurs, Participant's right to payment for an award under this Agreement shall be considered to be subject to a substantial risk of forfeiture in accordance with those terms as defined or referenced in Sections 409A and 3121(v)(2) of the Code; and (b) until the award is paid on the applicable Payment Date, Participant shall have merely an unfunded, unsecured promise to receive such award, and such unfunded promise shall not consist of a transfer of "property" within the meaning of Section 83 of the Code. Participant acknowledges that there may be adverse tax consequences upon the vesting or payment of the award or the disposition of the underlying shares of Common Stock and that Participant has been advised, and hereby is advised, to consult a tax advisor. Participant represents that Participant is in no manner relying on the Board, the Committee, the Company or any of its Affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) for tax advice or an assessment of such tax consequences.

18. No Right to Continued Employment, Service or Awards. Nothing in this Agreement, including the grant of the Restricted Stock Units, shall confer upon Participant any right to continued employment by, or any continued service relationship with, the Company or any Affiliate, or any other entity, or affect in any way the right of the Company or any such Affiliate, or any other entity, to terminate such employment or other service relationship at any time. The grant of the Restricted Stock Units in this Agreement is a one-time benefit that was made at the sole discretion of the Company and does not create any legal, contractual or other rights to receive any Restricted Stock Units or other Awards or any payment or benefits in the future, including any adjustment to wages, overtime, benefits or other compensation. Any future grant of the Restricted Stock Units or other Awards will be granted at the sole discretion of the Company. Any amendment, modification, or termination of the Plan shall not constitute a change or impairment of the terms and conditions of Participant's employment with the Company or any Affiliate, or any other entity, for any reason whatsoever.

19. Plan and Company Information. Participant may access important information about the Company and the Plan through the Company's website. Copies of the Plan and Plan Prospectus can be found by logging into the Fidelity NetBenefits website, which can be found at [www.netbenefits.fidelity.com](http://www.netbenefits.fidelity.com), and clicking on the "Stock Plans" tab and then following the prompts to the Plan documents. Copies of the Company's most recent Annual Report on Form 10-K, Proxy Statement and other information generally delivered to the Company's shareholders can be found at [www.eqt.com](http://www.eqt.com) by clicking on the "Investors" link on the main page and then "SEC Filings." Paper copies of such documents are available upon request made to the Company's Corporate Secretary.

**EQT CORPORATION**  
**20[ ] INCENTIVE PERFORMANCE SHARE UNIT PROGRAM**

EQT CORPORATION (the “Company”) hereby establishes this EQT CORPORATION 20[ ] INCENTIVE PERFORMANCE SHARE UNIT PROGRAM (this “Program”), in accordance with the terms provided herein.

WHEREAS, the Company maintains certain long-term incentive award plans, including the EQT Corporation 20[ ] Long-Term Incentive Plan (as amended from time to time, the “20[ ] Plan”), for the benefit of its directors and employees, of which this Program is a subset; and

WHEREAS, in order to further align the interests of executives and key employees with the interests of the Company’s shareholders, the Company desires to provide long-term incentive benefits through this Program, in the form of awards qualifying as “Performance Awards” under the 20[ ] Plan.

NOW, THEREFORE, the Company hereby provides for incentive benefits for executives and key employees of the Company and its Affiliates and adopts the terms of this Program on the following terms and conditions:

1. Purpose. The main purpose of this Program is to provide long-term incentive opportunities to executives and key employees to further align their interests with those of the Company’s shareholders and with the strategic objectives of the Company. Awards granted hereunder may be earned by achieving specified performance goals, are forfeited if defined performance levels are not achieved, and are subject to negative adjustment if, among other things, certain other performance measures are not attained. By placing a portion of the employee’s compensation at risk, the Company has an opportunity to reward exceptional performance or reduce the compensation opportunity when performance does not meet expectations. As a subset of the 20[ ] Plan, this Program is subject to and shall be governed by the terms and conditions of the 20[ ] Plan. Capitalized terms used herein and not otherwise defined shall have the meanings given to such terms in the 20[ ] Plan.

2. Effective Date. The effective date of this Program is [ ], 20[ ] (the “Effective Date”). This Program will remain in effect until payment following or in conjunction with the earlier of (a) [ ], 20[ ] or (b) the closing date of a Qualifying Change of Control pursuant to which all awards under this Program are paid in accordance with Section 6, unless otherwise amended or terminated as provided in Section 22. For purposes of this Program, a “Qualifying Change of Control” means a Change of Control (as then defined in the 20[ ] Plan) unless (i) all outstanding Performance Share Units under this Program are assumed by the surviving entity of the Change of Control (or otherwise equitably converted or substituted in connection with the Change of Control in a manner approved by the Committee) or (ii) the Company is the surviving entity of the Change of Control.

3. Eligibility. The Chief Executive Officer of the Company (the “CEO”) shall, in his or her sole discretion, select the employees of the Company and its Affiliates who shall be eligible to participate in this Program from those individuals eligible to participate in the 20[ ] Plan. The CEO’s selections will become participants in this Program (the “Participants”) only

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upon approval by the Committee, comprised in accordance with the requirements of the 20[ ] Plan (including, but not limited to, such individuals who are, or are expected to be, participants who are subject to Section 16 of the Exchange Act. In the event that an employee is hired by the Company or an Affiliate during the Performance Period (as defined in Section 5 below), the CEO shall, in his or her sole discretion, determine whether the employee will be eligible to participate in this Program; provided that the Committee must approve all new Participants to this Program, including Participants who are, or are expected to be, participants who are subject to Section 16 of the Exchange Act.

4. Incentive Performance Share Unit Awards. Awards under this Program are designated in the form of incentive performance share units (as adjusted from time to time in accordance with Section 15, the “Performance Share Units”), which are awards to be settled in shares of the Company’s common stock (“Common Stock”), as set forth in a Participant’s award agreement under this Program. Upon being selected to participate in this Program, each Participant shall be awarded a number of Performance Share Units, which award shall be proposed by the CEO and approved by the Committee. Unless otherwise indicated herein in a particular context, the term “Performance Share Units” includes any Dividend Units (as defined in Section 5 below) accumulated with respect to an award of Performance Share Units, as provided in Section 5. The Performance Share Units shall be held in bookkeeping accounts on behalf of the Participants and do not represent actual shares of Common Stock. A Participant shall have no right to exchange the Performance Share Units for cash, stock or any other benefit and shall be a mere unsecured creditor of the Company with respect to such Performance Share Units and any future rights to benefits.

5. Performance Conditions and Determination of Awarded Shares.

(a) Subject to Section 7, the number of Shares to be distributed to a Participant will be based on the Company’s performance as measured against the performance measures set forth on Attachment A over the Performance Period (the “Performance Conditions”). For purposes of this Program, the “Performance Period” shall mean the period commencing on [ ], 20[ ] and continuing thereafter until the earlier of (A) [ ], 20[ ] and (B) the closing date of a Qualifying Change of Control event pursuant to which all awards under this Program are paid in accordance with Section 6.

(b) A Participant’s “Awarded Shares” shall be calculated by multiplying (i) the number of Performance Share Units outstanding as of the conclusion of the Performance Period (subject to such adjustments, if any, set forth in the Participant’s award agreement), by (ii) the payout factor calculated as set forth on Attachment A (the “Payout Factor”). If Performance Share Units are outstanding on the record date for dividends or other distributions with respect to the Company’s Common Stock, then if such dividends or distributions are paid on or before the payment date for the Participant’s award as determined in accordance with Section 6 below, the dollar value or fair market value of such dividends or distributions with respect to the number of shares of Common Stock then underlying the Performance Share Units shall be converted into additional Performance Share Units in the Participant’s name (such additional Performance Share Units, the “Dividend Units”), based on the Fair Market Value of the Common Stock as of the date such dividends or distributions are paid. Any Dividend Units shall be subject to the

same performance conditions and transfer restrictions as apply to the Performance Share Units with respect to which they relate.

(c) Payments under this Program are expressly contingent upon achievement of the Performance Conditions.

6. Payment. Subject to Section 7 and except as provided in the remainder of this Section 6, each Participant's Awarded Shares will be distributed in shares of Common Stock, as set forth in the Participant's award agreement under this Program, no later than [ ], 20[ ]. Subject to Section 7, in the event of a Qualifying Change of Control, the Awarded Shares will be distributed in shares of Common Stock on the closing date of the transaction. Notwithstanding the first two sentences of this Section 6, the Committee may determine, in its discretion at any time and for any reason, to accelerate the payment of the Awarded Shares. No elections by any Participant shall be permitted with respect to the timing of any payments.

7. Change of Status. In making decisions regarding employees' participation in this Program and the extent to which Awarded Shares are payable in the case of an employee whose employment ceases prior to payment, the Committee may consider any factors that it deems to be relevant. Unless otherwise determined by the Committee, subject to the terms and provisions of (i) any written employment-related agreement that a Participant has with the Company (including any confidentiality, non-solicitation, non-competition, change of control or similar agreement), if any, or (ii) if the Participant is an Executive Severance Plan Participant, the Executive Severance Plan, as provided therein with respect to such Participant, the following shall apply in the case of a Participant whose employment ceases prior to payment of the Awarded Shares:

(a) Termination after Change of Control. In the event of a Change of Control that is not a Qualifying Change of Control, as a condition to the vesting of any Performance Share Units pursuant to Section 9.01(i) of the Plan, a Participant will be required to timely execute and not revoke within any time period to do so a full release of claims in a form acceptable to the Company within 30 days of the termination. Failure to satisfy this condition will result in forfeiture of such unvested Performance Share Units.

(b) Qualifying Termination. If a Participant's employment is terminated due to a Qualifying Termination, the Participant shall retain the opportunity to earn a pro-rata portion of his or her Performance Share Units determined by multiplying the number of such Participant's Performance Share Units by a fraction, the numerator of which is the number of calendar days during the Performance Period the Participant was employed prior to the date of such termination and the denominator of which is the total number of calendar days of the Performance Period (the "Pro-Rata PSUs"), contingent upon (i) the Participant timely executing (and not revoking within any time provided to do so) a full release of claims in a form provided by the Company within 30 days of his or her termination or resignation, as applicable, and (ii) achievement of the Performance Conditions set forth in Section 5; provided that if a Participant's employment is terminated voluntarily or such termination is a Qualifying Termination and, in either case, the Participant remains on the board of directors of the Company or any Affiliate whose equity is publicly traded on the New York Stock Exchange or the NASDAQ Stock Market following such termination of employment, the Participant shall retain all of his or her

Performance Share Units, contingent upon achievement of the Performance Conditions set forth in Section 5, for as long as the Participant remains on such board of directors, in which case any references herein to such Participant's employment shall be deemed to include his or her continued service on such board.

(i) Solely for purposes of this Program, a "Qualifying Termination" shall mean (A) the involuntary termination by the Company (or, as applicable, its successor) of a Participant's employment without Cause, (B) the voluntary termination of employment by a Participant due to Retirement or (C) such Participant's Disability.

(ii) Solely for purposes of this Program, "Retirement" shall mean, with respect to a Participant, the Participant's retirement as an employee of the Company or any of its Subsidiaries on or after reaching age 65 or such earlier age as may be otherwise determined by the Committee after at least ten (10) years of employment with the Company or any of its Subsidiaries.

(c) Death. If Participant's employment is terminated due to Participant's death, the Participant's estate or beneficiary will retain all of his or her Performance Share Units, contingent upon the Participant's estate or beneficiary timely executing (and not revoking within any time provided to do so) a full release of claims in a form provided by the Company within 60 days following the Participant's death.

(d) Other Termination. If a Participant's employment is terminated prior to the date on which the Performance Share Units are paid in accordance with Section 6 and such termination is not due to a Qualifying Termination, the Participant's Performance Share Units shall be forfeited.

(e) Payment upon Termination after Change of Control, Qualifying Termination, or Death. If any of the events described in Sections 7(a) and 7(b) occurs, any Performance Share Units that are retained (i.e., the Pro-Rata PSUs) shall be payable at the time specified in Section 6. In the event of the Participant's death as provided in Section 7(c), such Participant's Performance Share Units that are retained shall be distributed to the Participant's estate or beneficiary within 60 days following the Participant's death in shares of Common Stock as set forth in the Participant's award agreement under this Program, without giving effect to the Payout Factor. Notwithstanding any other provisions of this Program, Participants shall have no vested rights to any Performance Share Units prior to payment.

#### 8. Administration of the Plan.

(a) The Committee has responsibility for all aspects of this Program's administration, including:

(i) determining and certifying, in writing, the extent to which the Performance Conditions have been achieved prior to any payments under this Program,

- (ii) ensuring that this Program is administered in accordance with its provisions and the 20[ ] Plan,
- (iii) approving Program Participants,
- (iv) authorizing Performance Share Unit awards to Participants,
- (v) adjusting Performance Share Unit awards to account for extraordinary events,
- (vi) serving as the final arbiter of any disagreement between Program Participants, Company management, Program administrators, and any other interested parties to this Program, and
- (vii) maintaining final authority to amend, modify or terminate this Program at any time.

(b) Notwithstanding anything to the contrary in this Program, the Committee shall at all times retain the discretion with respect to all awards under this Program to reduce or eliminate, or determine the source of, any payment or award hereunder without regard to any particular factors specified in this Program. The interpretation and construction by the Committee of any provisions of this Program or of any adjusted Performance Share Units shall be final. No member of the Committee shall be liable for any action or determination made in good faith on this Program or any Performance Share Units thereunder. The Committee may designate another party to administer this Program, including Company management or an outside party. All conditions of the Performance Share Units must be approved by the Committee. As early as practicable prior to or during the Performance Period, the Committee shall approve the number of Performance Share Units to be awarded to each Participant. The associated terms and conditions of this Program will be communicated to Participants as close as administratively practicable to the date an award is made. The Participants will acknowledge receipt of the participant agreement and will agree to the terms of this Program in accordance with the Company's procedures.

9. Limitation of Rights. The Performance Share Units do not confer to Participants or their beneficiaries, executors or administrators any rights as shareholders of the Company (including voting and other shareholder rights) unless and until shares of Common Stock are in fact registered to or on behalf of a Participant in connection with the payment of the Performance Share Units. Upon conversion of the Performance Share Units into shares of Common Stock, a Participant will obtain full voting and other rights as a shareholder of the Company.

10. Tax Consequences to Participants/Payment of Taxes.

(a) It is intended that (i) until the Performance Conditions are satisfied, a Participant's right to payment for an award under this Program shall be considered to be subject to a substantial risk of forfeiture in accordance with those terms as defined or referenced in Sections 409A and 3121(v)(2) of the Code; (ii) the Awarded Shares shall be subject to employment taxes only upon the satisfaction of the Performance Conditions; and (iii) until the Awarded Shares are actually paid to a Participant, the Participant shall have merely an unfunded,

unsecured promise to be paid the benefit, and such unfunded promise shall not consist of a transfer of “property” within the meaning of Code Section 83. It is further intended that Participants will not be in actual or constructive receipt of compensation with respect to the Performance Share Units within the meaning of Code Section 451 until the Awarded Shares are paid. By participating in this Program, the Participant acknowledges that there may be adverse tax consequences upon the vesting or payment of the award or the disposition of the underlying shares of Common Stock and that the Participant has been advised, and hereby is advised, to consult a tax advisor. Each Participant represents that the Participant is in no manner relying on the Board, the Committee, the Company or any of its Affiliates or any of their respective managers, directors, officers, employees or authorized representatives (including attorneys, accountants, consultants, bankers, lenders, prospective lenders and financial representatives) for tax advice or an assessment of such tax consequences.

(b) The Company or any Affiliate employing the Participant (the “Employer”) has the authority and the right to deduct or withhold, or require a Participant to remit to the Employer, an amount sufficient to satisfy federal, state and local taxes (including the Participant’s portion of any payroll tax obligation) required by law to be withheld with respect to any taxable event arising as a result of an award under this Program. With respect to withholding required upon any taxable event arising as a result of this award, the Employer shall satisfy the tax withholding required by withholding shares of Common Stock from such shares otherwise issuable pursuant to this award having a Fair Market Value as of the date that the amount of tax to be withheld is to be determined equal to the amount of tax required to be withheld.

11. Recoupment Policy. Any shares of Common Stock distributed or amounts paid to a Participant under this Program, and any cash or other benefit acquired upon the sale of shares of Common Stock distributed to a Participant under this Program, shall be subject to the terms and conditions of any compensation recoupment policy adopted from time to time by the Company’s board of directors or any committee of such board, to the extent such policy is applicable to this Program and the Participant.

12. Nonassignment. A Participant shall not be permitted to assign, alienate or otherwise transfer his or her Performance Share Units, and any attempt to do so shall be void.

13. Impact on Benefit Plans. Payments under this Program shall not be considered as earnings for purposes of the Company’s or its Affiliates’ qualified retirement plans or any other retirement, compensation or benefit plan or program of the Company or its Affiliates unless specifically provided for and defined under such other plan or program. Nothing herein shall prevent the Company or its Affiliates from maintaining additional compensation plans and arrangements; provided, however, that no payments shall be made under such plans and arrangements if the effect thereof would be the payment of compensation otherwise payable under this Program regardless of whether the Performance Conditions were attained.

14. No Right to Continued Employment, Service or Awards. Nothing in this Program, including the grant of the Performance Share Units, shall confer upon the Participant any right to continued employment by, or any continued service relationship with, the Company or any Affiliate, or any other entity, or affect in any way the right of the Company or any such Affiliate,

or any other entity, to terminate such employment or other service relationship at any time. The grant of the Performance Share Units under this Program is a one-time benefit that was made at the sole discretion of the Company and does not create any legal, contractual or other rights to receive any Performance Share Units or other awards or any payment or benefits in the future, including any adjustment to wages, overtime, benefits or other compensation. Any future grant of the Performance Share Units or other awards will be granted at the sole discretion of the Company. Any amendment, modification, or termination of this Program shall not constitute a change or impairment of the terms and conditions of the Participant's employment with the Company or any Affiliate, or any other entity, for any reason whatsoever.

15. Successors and Assigns; Changes in Stock. The Company may assign any of its rights under this Program without the Participant's consent. All obligations of the Company under this Program shall be binding on and inure to the benefit of any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation or otherwise, of all or substantially all of the business and/or assets of the Company. In the event of any spin-off, split-off or split-up, or dividend in partial liquidation, dividend in property other than cash or Common Stock, or extraordinary distribution to holders of Common Stock, each Participant's Performance Share Units shall be appropriately adjusted to prevent dilution or enlargement of the rights of Participants that would otherwise result from any such transaction, provided such adjustment shall be consistent with Section 409A of the Code.

(a) In the case of a Change of Control, any obligation under this Program shall be handled in accordance with the terms of Sections 5 and 6 hereof. In any case not constituting a Change of Control in which the Common Stock is changed into or becomes exchangeable for a different number or kind of shares of stock or other securities of the Company or another corporation, or cash or other property, whether through reorganization, reclassification, recapitalization, stock split-up, combination of shares, merger or consolidation, then (i) the Awarded Shares shall be calculated based on the closing price of such common stock on the closing date of the transaction on the principal market on which such common stock is traded and (ii) there shall be substituted for each Performance Share Unit constituting an award the number and kind of shares of stock or other securities (or cash or other property) into which each outstanding share of Common Stock shall be so changed or for which each such share shall be exchangeable. In the case of any such adjustment, the Performance Share Units shall remain subject to the terms of this Program and the 20[ ] Plan.

16. Miscellaneous Definitions.

(a) "Executive Severance Plan" means that certain EQT Corporation Executive Severance Plan established effective May 19, 2020, as may be amended from time to time. For the avoidance of doubt, reference to a severance or similar agreement in the Plan includes the Executive Severance Plan with respect to any Executive Severance Plan Participant.

(b) "Executive Severance Plan Participant" means an individual who is, at the relevant time, a Participant under the Executive Severance Plan (with the definition of "Participant" for this purpose being set forth in Article II of the Executive Severance Plan).

17. Notice. Except as may be otherwise provided by the 20[ ] Plan or determined by the Committee and communicated to a Participant, notices and communications hereunder

must be in writing and shall be deemed sufficiently given if either hand delivered or if sent by fax or overnight courier, or by postage paid first class mail. Notices sent by mail shall be deemed received five (5) business days after mailed, but in no event later than the date of actual receipt. Notices shall be directed, if to a Participant, at such Participant's address indicated by the Company's records or, if to the Company, at the Company's principal executive office, Attention: Corporate Director, Compensation and Benefits.

18. Dispute Resolution. Any dispute regarding the payment of benefits under this Program or the 20[ ] Plan shall be resolved in accordance with the EQT Corporation Long-Term Incentive Dispute Resolution Procedures as in effect at the time of such dispute. A copy of such procedures is available on the Fidelity NetBenefits website, which can be found at [www.netbenefits.fidelity.com](http://www.netbenefits.fidelity.com).

19. Applicable Law. This Program shall be governed by and construed under the laws of the Commonwealth of Pennsylvania without regard to its conflict of law provisions.

20. Severability. In the event that any one or more of the provisions of this Program shall be held to be invalid, illegal or unenforceable, the validity, legality or enforceability of the remaining provisions shall not in any way be affected or impaired thereby.

21. Headings. The descriptive headings of the Sections of this Program are inserted for convenience of reference only and shall not constitute a part of this Program.

22. Amendment or Termination of this Program. This Program may be amended, suspended or terminated by the Company at any time upon approval by the Committee and following a determination that this Program is no longer meaningful in relation to the Company's strategy. Notwithstanding the foregoing, (a) no amendment, suspension or termination shall adversely affect a Participant's rights to his or her award after the date of the award; provided, however, that the Company may amend this Program from time to time without any Participant's consent to the extent deemed to be necessary or appropriate, in its sole discretion, to effect compliance with Code Section 409A or any other provision of the Code, including regulations and interpretations thereunder, which amendments may result in a reduction of benefits provided hereunder and/or other unfavorable changes to Participants, (b) no amendment may alter the time of payment as provided in Section 6 of this Program and (c) no amendment may be made following a Change of Control.

**PARTICIPANT AWARD AGREEMENT**

(20[ ] Incentive PSU Program)

[Grant Date]

Dear [Name]:

Pursuant to the terms and conditions of the EQT Corporation 20[ ] Long-Term Incentive Plan (as amended from time to time, the “Plan”) and the 20[ ] Incentive Performance Share Unit Program (the “Program”), effective [ ], 20[ ], the Management Development and Compensation Committee (the “Committee”) of the Board of Directors of EQT Corporation (the “Company”) grants you [ ] **Performance Share Units** (your “Award”). The terms and conditions of your Award, including, without limitation, vesting and distribution, shall be governed by the provisions of this Participant Award Agreement and the Program document attached hereto as Exhibit A; provided that your Award is also subject to the terms and limits included within the Plan. As approved, your Award will be settled in shares of Company common stock.

The terms contained in the Plan and the Program are hereby incorporated into and made a part of this Participant Award Agreement, and this Participant Award Agreement shall be governed by and construed in accordance with the Program and the Plan. In the event of any actual or alleged conflict between (a) the provisions of the Plan and the provisions of this Participant Award Agreement or the Program document, the provisions of the Plan shall be controlling and determinative, and (b) the provisions of this Participant Award Agreement or the Program document, on the one hand, and the terms of any written employment-related agreement that you have with the Company (including any confidentiality, non-solicitation, non-competition, change of control or similar agreement) or, if you are an Executive Severance Plan Participant (as defined in the Program document attached hereto as Exhibit A), on the other hand, the terms of such employment-related agreement or the Executive Severance Plan (as defined in the Program document attached hereto as Exhibit A), as applicable, shall be controlling and determinative.

You may access important information about the Company and the Plan through the Company’s website. Copies of the Plan and Plan Prospectus can be found by logging into the Fidelity NetBenefits website, which can be found at [www.netbenefits.fidelity.com](http://www.netbenefits.fidelity.com), and clicking on the “Stock Plans” tab and then following the prompts for your Plan documents. Copies of the Company’s most recent Annual Report on Form 10-K, Proxy Statement and other information generally delivered to the Company’s shareholders can be found at [www.eqt.com](http://www.eqt.com) by clicking on the “Investors” link on the main page and then “SEC Filings.” Paper copies of such documents are available upon request made to the Company’s Corporate Secretary.

Your Award under the Program will be effective only if, no later than 45 days after the date of this Participant Award Agreement, you accept your Award through the Fidelity NetBenefits website.

When you accept your Award through the Fidelity NetBenefits website, you shall be deemed to have (a) acknowledged receipt of this Award granted on the date of this Participant Award Agreement (the terms of which are subject to the terms and conditions of this Participant Award Agreement, the Program document and the Plan) and copies of this Participant Award Agreement, the Program document and the Plan, and (b) agreed to be bound by all the provisions of this Participant Award Agreement, the Program document and the Plan.

**SUBSIDIARIES OF EQT CORPORATION**  
(as of December 31, 2020)

Pursuant to Item 601(b)(21) of Regulation S-K, we have omitted some subsidiaries that, considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of December 31, 2020 under Rule 1-02(w) of Regulation S-X.

<b>Company</b>	<b>Jurisdiction of Organization</b>
EQT Aurora LLC	Pennsylvania
EQT Aurora HoldCo LLC	Delaware
EQT Capital Corporation	Delaware
EQT CHAP LLC	Pennsylvania
EQT CNEU LLC	Delaware
EQT Energy, LLC	Delaware
EQT Energy Supply, LLC	Delaware
EQT Energy Supply Holdings, LP	Delaware
EQT Gathering, LLC	Pennsylvania
EQT Investments Holdings, LLC	Delaware
EQT IP Ventures, LLC	Delaware
EQT MG, LLC	Delaware
EQT Minerals LLC	Delaware
EQT Production Company	Pennsylvania
EQT RE, LLC	Delaware
EQT SG, LLC	Delaware
ET Blue Grass, LLC	Delaware
MineralCo Holdings LLC	Delaware
Rice Drilling B LLC	Delaware
Rice Drilling D LLC	Delaware

**Consent of Independent Registered Public Accounting Firm**

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

- Registration Statement (Post-Effective Amendment No. 1 on Form S-8 to Form S-4 No. 333-219508) pertaining to the Rice Energy Inc. 2014 Long-Term Incentive Plan,
- Registration Statement (Form S-8 No. 333-221529) pertaining to the Rice Energy Inc. 2014 Long-Term Incentive Plan,
- Registration Statement (Form S-3 No. 333-158198) pertaining to the 2009 Dividend Reinvestment and Stock Purchase Plan,
- Registration Statement (Form S-3 No. 333-234151) pertaining to the registration of Debt Securities, Preferred Stock and Common Stock,
- Registration Statement (Form S-8 No. 333-185845) pertaining to the Employee Savings Plan,
- Registration Statement (Form S-8 No. 333-82193) pertaining to the 1999 Non-Employee Directors' Stock Incentive Plan,
- Registration Statement (Form S-8 No. 333-32410) pertaining to the Deferred Compensation Plan and the Directors' Deferred Compensation Plan,
- Registration Statement (Form S-8 No. 333-122382) pertaining to the 2005 Employee Deferred Compensation Plan and the 2005 Directors' Deferred Compensation Plan,
- Registration Statement (Form S-8 No. 333-152044) pertaining to the 2008 Employee Stock Purchase Plan,
- Registration Statement (Form S-8 No. 333-158682) pertaining to the 2009 Long-Term Incentive Plan,
- Registration Statement (Form S-8 No. 333-195625) pertaining to the 2014 Long-Term Incentive Plan,
- Registration Statement (Form S-8 No. 333-232657) pertaining to the 2019 Long-Term Incentive Plan,
- Registration Statement (Form S-8 No. 333-237953) pertaining to the 2020 Long-Term Incentive Plan,
- Registration Statement (Form S-8 No. 333-230970) pertaining to the Employee Savings Plan, and
- Registration Statement (Form S-8 No. 333-230969) pertaining to the Stock Option Inducement Award Agreement, dated April 22, 2019; the Performance Share Unit Inducement Award Agreement, dated April 22, 2019; the Restricted Stock Inducement Award Agreement (Cliff Vesting), dated April 22, 2019; and the Restricted Stock Inducement Award Agreement (Ratable Vesting), dated April 22, 2019;

of our reports dated February 17, 2021, with respect to the consolidated financial statements and schedule of EQT Corporation and Subsidiaries and the effectiveness of internal control over financial reporting of EQT Corporation and Subsidiaries included in this Annual Report (Form 10-K) of EQT Corporation and Subsidiaries for the year ended December 31, 2020.

/s/ Ernst & Young LLP

Pittsburgh, Pennsylvania  
February 17, 2021



### **CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS**

We hereby consent to the inclusion of our audit letter dated January 4, 2021, with respect to our audit of EQT Corporation's estimates of proved reserves and future revenue, as of December 31, 2020 (our Audit Letter), as an exhibit to, and reference of our firm in, the Annual Report on Form 10-K for the year ended December 31, 2020 of EQT Corporation, and to the incorporation of our Audit Letter and our firm by reference into EQT Corporation's effective registration statements under the Securities Act of 1933, as amended. We have no interest in EQT Corporation or in any of its affiliates. We have not been employed on a contingent basis, and we are not connected with EQT Corporation, or any of its affiliates, as a promoter, underwriter, voting trustee, director, officer, employee or affiliate.

### **NETHERLAND, SEWELL & ASSOCIATES, INC.**

By: /s/ Richard B. Talley, Jr., P.E.  
Richard B. Talley, Jr., P.E.  
Senior Vice President

Houston, Texas  
February 17, 2021

# CERTIFICATION

I, Toby Z. Rice, certify that:

1. I have reviewed this Annual Report on Form 10-K of EQT Corporation (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditor and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 17, 2021

/s/ Toby Z. Rice  
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 Toby Z. Rice  
 President and Chief Executive Officer

**CERTIFICATION**

I, David M. Khani, certify that:

1. I have reviewed this Annual Report on Form 10-K of EQT Corporation (the "registrant");
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditor and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

February 17, 2021

/s/ David M. Khani

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David M. Khani  
Chief Financial Officer

**CERTIFICATION**

In connection with the Annual Report of EQT Corporation ("EQT") on Form 10-K for the period ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned certify pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that, to their knowledge:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of EQT.

/s/ Toby Z. Rice

Toby Z. Rice

President and Chief Executive Officer

February 17, 2021

/s/ David M. Khani

David M. Khani

Chief Financial Officer

February 17, 2021

January 4, 2021

Ms. Sarah Fenton  
EQT Corporation  
625 Liberty Avenue, Suite 1700  
Pittsburgh, Pennsylvania 15222

Dear Ms. Fenton:

In accordance with your request, we have audited the estimates prepared by EQT Corporation (EQT), as of December 31, 2020, of the proved reserves and future revenue to the EQT interest in certain oil and gas properties located in Ohio, Pennsylvania, and West Virginia. It is our understanding that the proved reserves estimates shown herein constitute all of the proved reserves owned by EQT. We have examined the estimates with respect to reserves quantities, reserves categorization, future producing rates, future net revenue, and the present value of such future net revenue, using the definitions set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Rule 4-10(a). The estimates of reserves and future revenue have been prepared in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. We completed our audit on or about the date of this letter. This report has been prepared for EQT's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

The following table sets forth EQT's estimates of the net reserves and future net revenue, as of December 31, 2020, for the audited properties:

Category	Net Reserves			Future Net Revenue (M\$)	
	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	6,668.8	127,531.6	12,290,540.7	6,647,550.4	3,565,087.8
Proved Developed Non-Producing	347.5	13,957.5	459,771.5	269,921.0	134,186.8
Proved Undeveloped	401.0	7,273.4	6,114,701.0	2,446,011.9	267,740.3
Total Proved	7,417.3	148,762.5	18,865,013.1	9,363,483.4	3,967,014.9

Totals may not add because of rounding.

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

When compared on a well-by-well basis, some of the estimates of EQT are greater and some are less than the estimates of Netherland, Sewell & Associates, Inc. (NSAI). However, in our opinion the estimates shown herein of EQT's reserves and future revenue are reasonable when aggregated at the proved level and have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). Additionally, these estimates are within the recommended 10 percent tolerance threshold set forth in the SPE Standards. We are satisfied with the methods and procedures used by EQT in preparing the December 31, 2020, estimates of reserves and future revenue, and we saw nothing of an unusual nature that would cause us to take exception with the estimates, in the aggregate, as prepared by EQT.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk. EQT's estimates do not include probable or possible reserves that may exist for these properties, nor do they include any value for undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. EQT has included estimates of proved undeveloped reserves for certain locations that generate positive future net revenue but have negative present worth discounted at 10 percent based on the constant price and cost parameters discussed in subsequent paragraphs of this letter. These locations have been included based on EQT's declared intent to drill these wells, as evidenced by EQT's internal budget, reserves estimates, and price forecast.

Prices used by EQT are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2020. For oil and NGL volumes, the average West Texas Intermediate spot price of \$39.54 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of \$1.985 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are \$20.94 per barrel of oil, \$11.97 per barrel of NGL, and \$1.380 per MCF of gas.

Operating costs used by EQT are based on historical operating expense records and include contractual gathering fees. For the nonoperated properties, operating costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs for the operated properties are limited to direct lease- and field-level costs and EQT's estimate of the portion of its headquarters general and administrative overhead expenses necessary to operate the properties. Operating costs have been divided into per-well costs and per-unit-of-production costs. Capital costs used by EQT are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included for new development wells, production equipment, and EQT's estimate of the portion of its headquarters general and administrative overhead costs necessary to develop the properties. Abandonment costs used are EQT's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Operating, capital, and abandonment costs are not escalated for inflation.

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

It should be understood that our audit does not constitute a complete reserves study of the audited oil and gas properties. Our audit consisted primarily of substantive testing, wherein we conducted a detailed review of all properties. In the conduct of our audit, we have not independently verified the accuracy and completeness of information and data furnished by EQT with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of our examination something came to our attention that brought into question the validity or sufficiency of any such information or data, we did not rely on

such information or data until we had satisfactorily resolved our questions relating thereto or had independently verified such information or data. Our audit did not include a review of EQT's overall reserves management processes and practices.

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

Supporting data documenting this audit, along with data provided by EQT, are on file in our office. The technical persons primarily responsible for conducting this audit meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Steven W. Jansen, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2011 and has over 4 years of prior industry experience. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**

Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III

By:

C.H. (Scott) Rees III, P.E.

Chairman and Chief Executive Officer

/s/ Steven W. Jansen

By:

Steven W. Jansen, P.E. 112973  
Vice President

/s/ Edward C. Roy III

By:

Edward C. Roy III, P.G. 2364  
Vice President

Date Signed: January 4, 2021

Date Signed: January 4, 2021

SWJ:STH

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