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, 2022

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	**25-0464690**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
625 Liberty Avenue, Suite 1700 **Pittsburgh, Pennsylvania**	**15222**
(Address of principal executive offices)	(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	☒	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

Indicate by check mark whether the registrant 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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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, 2022: $12.6 billion

As of February 10, 2023, 360,360,130 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 2023 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, 2022 and is incorporated by reference in Part III to the extent described therein.

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Glossary of Commonly Used Terms, Abbreviations and Measurements

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.

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 reasonably 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.

turned-in-line – when a well is completed, producing and initially turned to sales.

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
FERC – Federal Energy Regulatory Commission
FTC – Federal Trade 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
WTI – West Texas Intermediate crude oil

Measurements

Bbl = barrel

Bcf = billion cubic feet

Bcfe = billion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

Btu = one British thermal unit

Dth = dekatherm or million British thermal units

Mbbl = thousand barrels

Mcf = thousand cubic feet

Mcfe = thousand cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

MMbbl = million barrels

MMBtu = million British thermal units

MMcf = million cubic feet

MMcfe = million cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

MMDth = million dekatherm

Tcfe = trillion cubic feet of natural gas equivalents, with one barrel of NGLs and crude oil being equivalent to 6,000 cubic feet of natural gas

SUMMARY OF RISK FACTORS

We believe that the principal risks associated with our business, and consequently the principal risks associated with an investment in our equity or debt securities, generally fall within the following 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 hedge positions, leverage, credit ratings, tax law changes 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 systems and infrastructure enable us to efficiently supply our natural gas, NGLs and oil to the market, they are also susceptible to physical and 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 operate in the Appalachian Basin, and a substantial majority of our midstream and water services are provided by one provider, Equitrans Midstream Corporation (Equitrans Midstream), 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.

We describe these risks in greater detail under Item 1A., "Risk Factors."

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 (the Exchange Act), 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," the section "Trends and Uncertainties" 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 these plans and programs; total resource potential and drilling inventory duration; projected production and sales volume and growth rates; natural gas prices; changes in basis and the impact of commodity prices on our business; potential future impairments of our assets; projected well costs and capital expenditures; 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 results of such initiatives; projected gathering and compression rates; potential acquisition transactions or other strategic transactions, the timing thereof and our ability to achieve the intended operational, financial and strategic benefits from any such transactions, including the Tug Hill and XcL Midstream Acquisition (defined in Note 6 to the Consolidated Financial Statements); the amount and timing of any repayments, redemptions or repurchases of our common stock, outstanding debt securities or other debt instruments; our ability to retire our debt and the timing of such retirements, if any; the projected amount and timing of dividends; projected cash flows and free cash flow, and the timing thereof; 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 and projected margin posting obligations; 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, except as required by law, we do not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

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 volume, we are the largest producer of natural gas in the United States. As of December 31, 2022, we had 25.0 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 2.0 million gross acres, including approximately 1.8 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 measure sustainability through our best-in-class team and culture, ESG-focused operations, substantial inventory of core drilling locations and strong balance sheet. 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 and recycled water (as opposed to truck-transported water), and provides 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, environmental protection and social responsibility.

We believe that combo-development projects are key to delivering sustainably low well costs and higher returns on invested capital. Our business model has been developed to enable us to generate sustainable free cash flow and correspondingly, we have implemented a robust capital allocation strategy directed at responsibly developing our assets while also returning capital to our shareholders through a combination of dividends, strategic share repurchases, and debt retirements. We are also focused on maintaining investment grade credit metrics, which allows us to capture a lower cost of capital and further enhance shareholder returns.

Our strategy, and combo-development projects in particular, requires 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. Furthermore, we believe the benefits of our operating model can be magnified through select strategic transactions, and part of our strategy includes creating value through mergers and acquisitions, divestitures, joint ventures and similar business transactions, as well as investing in energy transition opportunities directed at complementing, and in certain cases diversifying, our core business operations.

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, while simultaneously helping to address energy security and affordability both domestically and globally.

2022 Highlights

- Generated $3,466 million of net cash provided by operating activities.
- Achieved investment grade credit ratings from Fitch and S&P and upgraded to positive outlook at Moody's.
- Delivered on our capital return strategy through debt retirements, share buybacks and dividends.
    - Repaid or repurchased $826 million aggregate principal of senior notes.
    - Repurchased $85 million aggregate principal of convertible notes, reducing our fully diluted share count by 5.7 million shares.
    - Repurchased $393 million of common stock, reducing our share count by 13.1 million shares.
    - Increased quarterly base dividend by 20% to $0.15 per share ($0.60 per share annualized).
    - Paid $204 million in dividends to shareholders.
- Authorized to repurchase up to $2.0 billion of our shares through December 31, 2023.
- Announced agreement to acquire Tug Hill and XcL Midstream.
- Added to the S&P 500 Index, joining top companies across all sectors of the U.S. economy.
- Successfully completed our initiative to eliminate natural gas-powered pneumatic devices from our production operations, meaningfully reducing our methane and carbon emissions.
- Announced Appalachian Regional Clean Hydrogen Hub (ARCH2) collaboration with the State of West Virginia and leading energy and technology companies.
- Announced Appalachian Methane Initiative (AMI) collaboration to further enhance methane monitoring throughout the Appalachian Basin.

Outlook

In 2023, we expect to spend approximately $1.7 to $1.9 billion in total capital expenditures, excluding amounts attributable to noncontrolling interests and acquisitions. We expect to allocate the planned capital expenditures as follows: approximately $1,400 to $1,535 million to fund reserve development, approximately $120 to $140 million to fund land and lease acquisitions, approximately $125 to $160 million to fund other production infrastructure and approximately $55 to $65 million applied towards capitalized overhead. In 2023, we expect our sales volume to be 1,900 to 2,000 Bcfe, excluding amounts attributable acquisitions.

We are committed to maintaining investment grade credit metrics and we have a goal to retire at least $4.0 billion of our debt between January 1, 2022 and December 31, 2023, subject to the occurrence and timing of the closing of the Tug Hill and XcL Midstream Acquisition and the overall performance of the commodity markets. Our capital allocation plan is focused on maintaining production volumes while also returning capital to shareholders, including through our share repurchase program, under which we are authorized to repurchase up to $2.0 billion of our outstanding common stock, and through our quarterly cash dividend, which is currently an annual rate of $0.60 per share. Furthermore, we have aligned our hedge strategy in a manner that we believe will mitigate the risk of volatility of future natural gas and NGLs prices, thereby enabling us to execute on our capital expenditure, debt retirement and shareholder return strategy.

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 "Critical Accounting Policies and Estimates" included in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements for a discussion of our accounting policies and significant assumptions related to accounting for natural gas, NGLs and oil producing activities and 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."

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, 2022		
	Natural Gas	NGLs and Crude Oil	Total
	(Bcf)	(MMbbl)	(Bcfe)
Proved developed reserves	16,541	162	17,514
Proved undeveloped reserves	7,284	34	7,489
Total proved reserves	23,825	196	25,003

	December 31, 2022			
	Marcellus	Ohio Utica	Other	Total
	(Bcfe)			
Proved developed reserves	16,718	708	88	17,514
Proved undeveloped reserves	7,468	17	4	7,489
Total proved reserves	24,186	725	92	25,003

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, 2022			
	Pennsylvania	West Virginia	Ohio	Total
	(Bcfe)			
Proved developed producing reserves	12,775	3,461	680	16,916
Proved developed non-producing reserves	461	109	28	598
Proved undeveloped reserves	4,933	2,539	17	7,489
Total proved reserves	18,169	6,109	725	25,003
Gross proved undeveloped drilling locations	256	126	6	388
Net proved undeveloped drilling locations	194	106	1	301

Our 2022 total proved reserves increased by 41 Bcfe, or 0.2%, compared to 2021 due to extensions, discoveries and other additions of 2,495 Bcfe and acquisitions of 141 Bcfe from the 2022 Asset Acquisition (defined in Note 6 to the Consolidated Financial Statements), partly offset by production of 1,940 Bcfe and revisions to previous estimates of 655 Bcfe.

Our 2022 proved undeveloped reserves decreased by 254 Bcfe, or 3.3%, compared to 2021. The following table provides a rollforward of our proved undeveloped reserves.

	Proved Undeveloped Reserves
	(Bcfe)
Balance at January 1, 2022	7,743
Conversions into proved developed reserves	(1,365)
Acquisition of in-place reserves	141
Revision of previous estimates (a)	(1,107)
Extensions, discoveries and other additions (b)	2,077
Balance at December 31, 2022	7,489

(a) Composed of (i) negative revisions of 1,625 Bcfe related to proved undeveloped locations that are no longer expected to be developed as proved reserves within five years of initial booking as a result of development schedule changes, driven largely by third-party impacts, which has pushed planned completion dates into a future period from when originally planned; and (ii) positive revisions of 518 Bcfe due primarily to changes in ownership interests.

(b) Composed of 2,077 Bcfe from proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2022 reserve development that expanded the number of our proven locations and additions to our five-year drilling plan.

As of December 31, 2022, we had zero wells with proved undeveloped reserves that had remained undeveloped for more than five years from their time of booking.

The following table provides the estimated future net cash flows, excluding open derivative contracts, from proved reserves, the present value of those net cash flows discounted at a rate of 10% (PV-10) and the prices used in projecting net cash flows over the past three years. Our reserve estimates do not include any probable or possible reserves.

	Years Ended December 31,		
	2022	2021	2020
	(Millions, except prices)		
Future net cash flow	$ 87,612	$ 36,567	$ 7,543
Standardized measure of discounted future net cash flow	40,065	17,281	3,366
PV-10 (a)	51,512	21,496	3,967
Prices, including regional adjustments:			
Natural gas price ($/Mcf)	$ 5.543	$ 2.694	$ 1.380
NGLs price ($/Bbl)	38.66	29.95	11.97
Oil price ($/Bbl)	76.83	51.57	20.94

(a) PV-10 is a non-GAAP financial measure. PV-10 is derived from the standardized measure of discounted future net cash flows (the Standardized Measure), which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 differs from the Standardized Measure because it does not include the effects of income taxes on future net revenues. We believe the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of our oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of our proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor the Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. See below for a reconciliation of the Standardized Measure to PV-10.

Future net cash flows represent projected revenues from the sale of proved reserves, net of production and development costs (including transportation and gathering expenses, operating expenses and production taxes) and net of estimated income taxes. Revenues are based on a twelve-month unweighted average of the first-day-of-the-month pricing, without escalation. Future cash flows are reduced by estimated production costs, administrative costs, costs to develop and produce the proved reserves and abandonment costs, all based on current economic conditions at each year-end. There can be no assurance that the proved reserves will be produced in the future or that prices, production or development costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information. See Note 16 to the Consolidated Financial

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

The following table provides the reconciliation of the Standardized Measure to PV-10.

	Years Ended December 31,		
	2022	2021	2020
		(Millions)	
Standardized measure of discounted future net cash flow	$ 40,065	$ 17,281	$ 3,366
Estimated discounted income taxes on future net revenues	11,447	4,215	601
PV-10	$ 51,512	$ 21,496	$ 3,967

If the prices used in the calculation of the Standardized Measure instead reflected five-year strip pricing as of December 30, 2022 and held constant thereafter using (i) the NYMEX five-year strip adjusted for regional differentials using Texas Eastern Transmission Corp. M-2, Transcontinental Gas Pipe Line, Leidy Line, and Tennessee Gas Pipeline Co., Zone 4-300 Leg 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 holding all other assumptions constant, our total proved reserves would be 24,971 Bcfe, the Standardized Measure after taxes of our proved reserves would be $22,625 million and the discounted future net cash flows before taxes would be $29,169 million. The average realized product prices weighted by production over the remaining lives of the properties would be $50.13 per barrel of oil, $27.30 per barrel of NGLs and $3.565 per Mcf of gas.

The NYMEX strip price for 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 for proved reserves and do not comply with SEC pricing assumptions. We believe that the presentation of reserve volume 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 certain amounts of future production based on 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 are not necessarily an accurate projection of future oil and gas prices. Actual future prices may vary significantly from 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 2,400 net locations in the Pennsylvania and West Virginia Marcellus Shale. At our current drilling pace, these net locations provide more than 20 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,		
	2022	2021	2020
		(Millions)	
Marcellus	$ 1,102	$ 788	$ 737
Utica	29	40	102
Total	$ 1,131	$ 828	$ 839

For the years ended December 31, 2022, 2021 and 2020, lease operating expenses, excluding production taxes per Mcfe were $0.08, $0.07 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 32% 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, 2022			
	Pennsylvania	West Virginia	Ohio	Total
Total gross productive acreage	465,353	133,541	52,480	651,374
Total gross undeveloped acreage	887,195	361,896	115,453	1,364,544
Total gross acreage	1,352,548	495,437	167,933	2,015,918
Total net productive acreage	384,185	144,833	38,341	567,359
Total net undeveloped acreage	777,936	339,701	104,338	1,221,975
Total net acreage	1,162,121	484,534	142,679	1,789,334
Average net revenue interest of proved developed reserves (a)	59.2 %	76.1 %	43.9 %	61.1 %

(a) As of December 31, 2022, the average net revenue interest of proved developed reserves was 79.8% for southwestern Pennsylvania and 30.5% for northeastern Pennsylvania.

We have an active lease renewal program in areas targeted for development. In the event that production is not established or we do not extend or renew the terms of our expiring leases, 25,797, 27,728 and 17,096 of our net undeveloped acreage as of December 31, 2022 will expire in the years ending December 31, 2023, 2024 and 2025, respectively.

The following table summarizes our natural gas, NGLs and oil produced and sold volume by state.

	Pennsylvania	West Virginia	Ohio	Total
	(MMcfe)			
Year Ended December 31, 2022	1,493,568	323,113	123,362	1,940,043
Year Ended December 31, 2021	1,422,294	271,747	163,776	1,857,817
Year Ended December 31, 2020	1,051,869	267,708	178,215	1,497,792

Productive Wells

The following table summarizes our productive and in-process natural gas wells. We had no productive or in-process oil wells as of December 31, 2022.

	December 31, 2022			
	Pennsylvania	West Virginia	Ohio	Total
Productive wells:				
Total gross productive wells (a)	3,666	744	287	4,697
Total net productive wells	2,758	702	143	3,603
In-process wells:				
Total gross in-process wells	196	155	3	354
Total net in-process wells	165	142	1	308

(a) Of our total gross productive wells, there are 608 gross conventional wells in Pennsylvania and 3 gross conventional wells in West Virginia. We have no gross conventional wells in Ohio.

Drilling Activity

The following table summarizes our completed net productive development wells. During the years ended December 31, 2022, 2021 and 2020, we did not drill any net dry development, net productive exploratory or net dry exploratory wells.

	Pennsylvania	West Virginia	Ohio	Total
Year Ended December 31, 2022	55	26	2	83
Year Ended December 31, 2021	60	17	5	82
Year Ended December 31, 2020	84	6	8	98

The following table summarizes the gross and net wells on which we commenced drilling operations (spud) in 2022.

	Pennsylvania	West Virginia	Ohio	Total
Gross wells spud	123	17	16	156
Net wells spud	75	7	2	84

Markets and Customers

Natural Gas Sales. Natural gas is a commodity and, therefore, we typically receive market-based pricing for our produced natural gas. 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 and limited pipeline capacity to transport the supply to other regions. To protect our 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. We also enter into derivative instruments to hedge basis. 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,		
	2022	2021	2020
Natural gas ($/Mcf):			
Average sales price, excluding cash settled derivatives	$ 6.22	$ 3.54	$ 1.73
Average sales price, including cash settled derivatives	3.00	2.38	2.37
NGLs, excluding ethane ($/Bbl):			
Average sales price, excluding cash settled derivatives	$ 53.26	$ 44.50	$ 20.51
Average sales price, including cash settled derivatives	49.35	32.18	20.39
Ethane ($/Bbl):			
Average sales price	$ 14.20	$ 8.85	$ 3.48
Oil ($/Bbl):			
Average sales price	$ 77.06	$ 56.82	$ 25.57
Natural gas, NGLs and oil ($/Mcfe):			
Average sales price, excluding cash settled derivatives	$ 6.24	$ 3.66	$ 1.77
Average sales price, including cash settled derivatives	3.17	2.50	2.37

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, 2022, approximately 44% of our sales volume reaches 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 3.6 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.

During 2021, we entered into a long-term asset management agreement with an investment grade entity, pursuant to which, we agreed to deliver and sell up to 525,000 Dth of natural gas per day to the investment grade entity for a period of up to six years while managing and using our committed capacity on the Mountain Valley Pipeline upon its in-service date. The asset management agreement is subject to currently unsatisfied conditions; therefore, its impacts have been excluded from the firm capacity on the Mountain Valley Pipeline noted above and the schedule of total gross commitments summarized in the table below.

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, 2022.

	Natural Gas	NGLs
	(Bcf)	**(Mbbl)**
Years Ending December 31,		
2023	1,350	9,423
2024	606	5,490
2025	408	5,475
2026	360	4,250
2027	328	3,650
Thereafter	2,155	34,690

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 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 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 allows the statutory pooling or unitization of tracts to facilitate development and exploration. In Pennsylvania, lease integration legislation authorizes joint development of existing contiguous leases. West Virginia historically only allowed statutory pooling of Utica acreage and for other deep wells, which required operators to rely on voluntary pooling of lands and leases to develop Marcellus acreage. However, in March 2022, the West Virginia legislature passed Senate Bill 694 allowing the operator of a proposed horizontal well (regardless of formation) to develop the acreage of non-consenting and unlocatable and unknown owners if 75% of the mineral interest owners and 55% of the working interest owners in the proposed well unit consent to the development. Senate Bill 694, and the corresponding unitization provisions thereunder, went into effect on June 7, 2022. Additionally, 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 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 or alter their derivative activities. The Dodd-Frank Act also created new categories of regulated market participants, such as “swap dealers” (SDs) and “security-based swap dealers” (SBSDs) that are subject to significant new capital, registration, recordkeeping, reporting, disclosure, business conduct and other regulatory requirements, a large number of which have been implemented. This regulatory framework has significantly increased the costs of entering into derivatives transactions for end-users of derivatives, such as ourselves. In particular, new margin requirements and capital charges, even when not directly applicable to us, have increased the pricing of derivatives that we transact in.

New exchange trading margin regulations, trade reporting requirements and position limits may lead to changes in the liquidity of our derivative transactions or higher pricing. That said, 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 the Dodd-Frank Act. Additionally, our uncleared swaps are not subject to regulatory margin requirements. Finally, we believe that the majority, if not all, of our hedging activities constitute bona fide hedging under applicable federal and exchange-mandated position limits rules and are not materially impacted by the limitations under such rules.

In addition to U.S. laws and regulations relating to derivatives, certain non-U.S. regulatory authorities have passed or proposed, or may propose in the future, legislation similar to that imposed by the Dodd-Frank Act. For example, European Union legislation imposes position limits on certain commodity transactions, and the European Market Infrastructure Regulation (EMIR) requires reporting of derivatives and various risk mitigation techniques to be applied to derivatives entered into by parties that are subject to EMIR. Other similar regulations are in development throughout the globe and may increase our cost of doing business even if not directly binding on us.

Regulators periodically review or audit our compliance with applicable regulatory requirements. We anticipate that compliance with existing laws and regulations governing our current operations will not have a material adverse effect on 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 almost $1.5 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 the aggregate volume 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 penalties.

The CFTC also holds authority to monitor certain segments of the physical, futures and other derivatives energy commodities markets, 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 required to observe anti-market manipulation and disruptive trading practices laws and related regulations enforced by 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, transportation 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 natural 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 natural 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, and 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 regulations issued by the 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 $1.4 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight and enforcement authority as discussed above.

The price we receive from the sale of our produced oil and NGLs may be affected by the cost of transporting such 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's five-year index level for 2021 through 2026 went into effect on July 1, 2021. In January 2022, the FERC issued an order on rehearing, lowering the index level and directing oil pipelines to recompute their ceiling levels for July 1, 2021 through June 30, 2022 to ensure compliance with the new index level.

Environmental, Health and Safety Regulations. 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 certain 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 us to acquire 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, remediate or mitigate pollution from operations, such as plugging abandoned wells or closing earthen pits; establish specific health and safety 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 our 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 environmental and occupational health and 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 water 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 currently classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. 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 offsite 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 the 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, clean-up 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, known as 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 rule defining the scope of the EPA's and the Corps' jurisdiction over waters of the United States (WOTUS), which never took effect before being replaced by the Navigable Waters Protection Rule (NWPR) in December 2019. A coalition of states and cities, environmental groups, and agricultural groups challenged the NWPR, which was vacated by a federal district court in August 2021. The EPA is undergoing a rulemaking process to redefine the definition of WOTUS which could be impacted by the U.S. Supreme Court's pending decision in *Sackett v. EPA.* a case regarding the proper test in determining whether wetlands qualify as WOTUS. A final rule, known as "Rule 1" was announced by the EPA and the Corps in December 2022. The EPA and Corps are expected to propose a second rule, know as "Rule 2," further refining Rule 1 by November 2023 and issue a final rule by July 2024. In addition, in an April 2020 decision further defining the scope of the CWA, 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. To the extent a new rule or further litigation 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 and may impose substantial potential liability for the costs of removal, remediation and natural resource and other damages.

Air Emissions. Through the federal Clean Air Act (CAA) and comparable state and local laws and regulations, the EPA regulates emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and modified and existing facilities may be required to obtain additional permits.

In June 2016, the EPA finalized regulations establishing 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 two sets of amendments to the 2016 Subpart OOOOa standards. The first amendment, known as the "2020 Technical Rule", reduced the 2016 rule's fugitive emissions monitoring requirements and expanded exceptions to pneumatic pump requirements, among other changes. The second amendment, known as the "2020 Policy Rule", rescinded the methane-specific requirements for certain oil and natural gas sources in the production and processing segments. On January 20, 2021, President Biden issued an Executive Order directing the EPA to rescind the 2020 Technical Rule by September 2021 and consider revising the 2020 Policy Rule. On June 30, 2021, President Biden signed a Congressional Review Act (CRA) resolution passed by Congress that revoked the 2020 Policy Rule. The CRA did not address the 2020 Technical Rule.

Further, on November 15, 2021, the EPA issued a proposed rule intended to reduce methane emissions from oil and gas sources. The proposed rule would make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA, including intermittent vent pneumatic controllers and associated gas and liquids unloading facilities. In addition, the proposed rule would establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. Under the proposed rule, states would have three years to develop their compliance plan for existing sources and the regulations for new sources would take effect immediately upon issuance of a final rule. On November 11, 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to identify large emissions events, referred to in the proposed rule as “super emitters.” The EPA is expected to issue a final rule by May 2023.

As a result of these regulatory changes, the scope of any final air emissions regulations or the costs for complying with such regulations are uncertain. We may incur costs as necessary to remain in compliance with these regulations. Obtaining or renewing permits also has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

Climate Change and Regulation of Methane and Other Greenhouse Gas Emissions. In December 2015, the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change resulted in nearly 200 countries, including the United States, coming together to develop the Paris Agreement, which calls for the signatories to the agreement to undertake "ambitious efforts" to limit increases in the average global temperature. Although the agreement does not create any binding obligations for nations to limit their greenhouse gas (GHG) emissions, it does include pledges to voluntarily limit or reduce future emissions. In 2020, President Trump completed the process of withdrawing the United States from the Paris Agreement. However, on February 19, 2021 the United States rejoined the Paris Agreement under the mandate of President Biden. In addition, in September 2021, President Biden publicly announced the Global Methane Pledge, a pact that aims to reduce global methane emissions to at least 30% below 2020 levels by 2030. Since its formal launch at the 26th Conference of Parties to the United Nations Convention on Climate Change (COP26), over 100 countries have joined the Global Methane Pledge. Most recently, at the 27th Conference of Parties (COP27), President Biden announced the EPA’s proposed standards to reduce methane emissions from existing oil and gas sources and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement.

In August 2022, President Biden signed into law the Inflation Reduction Act of 2022 (Inflation Reduction Act), which among other things, includes a methane emissions reduction program that amends the CAA to include a Methane Emissions and Waste Reduction Incentive Program for petroleum and natural gas systems. This program requires the EPA to impose a “waste emissions charge” on certain oil and gas sources that are already required to report under the EPA’s Greenhouse Gas Reporting Program (GHGRP). The waste emissions charge will become effective on January 1, 2024 and will apply to a facility’s emissions (as reported under the EPA’s GHGRP) in excess of a specified threshold, as set forth in the Inflation Reduction Act based upon the emitting facility’s segment category. The fee for emissions in excess of the specified threshold will initially be $900 per metric ton of methane emitted in 2024 and will increase to $1,200 in 2025, and $1,500 in 2026. For petroleum and natural gas production facilities, the threshold is methane emissions in excess of 0.2% of the natural gas sent to sale from the facility. If a facility’s methane emissions do not exceed the 0.2% threshold, no fee would be assessed under the rule. Our current methane emissions do not exceed the 0.2% threshold, and accordingly, we do not believe we will be assessed a fee under the Methane Emissions and Waste Reduction Incentive Program.

The $1 trillion legislative infrastructure package passed by Congress in November 2021 includes a number of climate-focused spending initiatives targeted at climate resilience, enhanced response and preparation for extreme weather events, and clean energy and transportation investments. The Inflation Reduction Act also provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture and other programs directed at addressing climate change.

Additionally, 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 Pennsylvania Department of Environmental Protection (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 Pennsylvania Environmental Quality Board (EQB) approved promulgation of the RGGI regulation, and a public comment period and hearings regarding the regulation commenced at the end of 2020. Pennsylvania ultimately became a member of RGGI, though its membership is currently the subject of legal challenges. Depending on the outcome of such litigation, Pennsylvania's membership in RGGI will result in increased operating costs should we be required to purchase emission allowances in connection with our operations.

Any legislation or regulatory programs at the federal, state or city levels designed to reduce methane or other GHG emissions could increase the cost of consuming, and thereby reduce demand for, the natural gas, NGLs and oil we produce. Consequently, legislation and regulatory programs designed to reduce emissions of methane or other GHGs could have an adverse effect on our business, financial condition and results of operations.

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

Notwithstanding potential risks related to climate change, natural gas continues to represent a major share of global energy use, and certain private sector studies project continued growth in demand for the next two decades. 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 some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events. If any such effects were to occur, they 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 multiple pre-drill samplings for all water sources within 3,000 feet of our sites and post-drill samplings for sources within 1,500 feet of our sites.

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 has prohibited the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. 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 2020, the Pennsylvania 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 and comparable state laws that regulate the protection of the health and safety of employees. In addition, the Occupational Health and Safety Administration's (OSHA) hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require us to maintain information about hazardous materials used or produced in our operations and this information is required to 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. 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 (NMFS) issued three rules amending implementation of the ESA regulations revising, among other things, the process for listing species and designating critical habitat, which was challenged by a coalition of states and environmental groups. In addition, in December 2020, the FWS amended its regulations governing critical habitat designations, which were also the subject of litigation. In June and July 2022, the FWS issued final rules rescinding the regulations defining "habitat" and governing critical habitat exclusions. Protections similar to the ESA 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 revoked the rule in October 2021 and issued an advance notice of proposed rulemaking seeking comment on the Department's plan to develop regulations that authorize incidental taking under certain prescribed conditions. The notice of proposed rulemaking was due to be issued in August 2022; however, the status of the rulemaking is still pending. Future implementation of the rules impacting 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 13 to the Consolidated Financial Statements for a description of expenditures related to environmental matters.

Human Capital Resources

As of December 31, 2022, we had 744 permanent employees, none of whom were subject to a collective bargaining agreement. Of our total permanent employee base, 74% are male and 26% are female. Approximately 66% of our permanent employees work remotely, with 91% residing in Pennsylvania or 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. Our cloud-based 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 as well as to solicit suggestions and comments from all employees. We believe that this helps promote real-time feedback and a greater degree of employee engagement, which lays the foundation for the success of our remote workforce.

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 (alternating Fridays).

We offer an "equity-for-all" program, pursuant to which, we grant annual equity awards to all of our permanent employees. With the equity-for-all program, all of our permanent employees become owners of EQT and have the opportunity to share directly in our financial success.

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 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, 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,		
	2022	2021	2020
		(Thousands)	
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	$ 12,114,168	$ 6,804,020	$ 2,650,299
(Loss) gain on derivatives	(4,642,932)	(3,775,042)	400,214
Net marketing services and other	26,453	35,685	8,330
Total operating revenues	$ 7,497,689	$ 3,064,663	$ 3,058,843

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 occur, our business, financial condition or results of operations could suffer and the trading price of our common stock could decline.

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 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, emission of GHGs, and limitations on hydraulic fracturing;
- shortages of or delays in obtaining equipment, rigs, materials, qualified personnel or water (for hydraulic fracturing activities);
- supply chain disruptions or labor shortage impacts, including as a result of the COVID-19 pandemic or other global pandemics;
- equipment failures, accidents or other unexpected operational events;
- lack of available gathering and water facilities or delays in the construction of gathering and water facilities;
- lack of available capacity on interconnecting transportation pipelines;
- adverse weather conditions, such as flooding, droughts, freeze-offs, landslides, 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 issues; 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, wastewater, 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.

A terrorist attack or armed conflict targeting our systems or natural gas infrastructure generally could materially adversely impact our operations.

Growing geopolitical instability and armed conflicts (including the armed conflict between Russia and Ukraine) has resulted in energy infrastructure becoming a more prominent target of attack by terrorists and conflicting countries. Natural gas, NGLs and oil related facilities, including those operated by us or our service providers, could be direct targets of physical or cyber attacks, and, if infrastructure integral to our operations is destroyed or damaged, we may experience a significant disruption in our operations. Any such disruption could materially adversely affect our financial condition, results of operations and cash flows. Costs for insurance and other security may increase as a result of increased threats, and certain insurance coverage may become more difficult to obtain, if available at all.

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 sand and water and corresponding materials sourcing and distribution systems, including railroads; 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, if production is not established within the spacing units covering our undeveloped acres in accordance with the requisite timeframe set forth in the applicable lease, our 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 6% 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 or commodity prices, 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 or 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 our 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. For the years ended December 31, 2022, 2021 and 2020, we recorded impairment and expiration of leases of $176.6 million, $311.8 million and $306.7 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 our 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 our production volume 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 wastewater generated in our operations, as well as weather conditions, natural gas, NGLs and oil price volatility, regulatory 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 due to dry wells, but also as a result of productive wells that perform below expectations or that 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. Our 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 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 our 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 reserves 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 and development 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 "Critical Accounting Policies and Estimates" included in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements for a discussion of our accounting policies and significant assumptions related to accounting for natural gas, NGLs and oil producing activities and impairment of our oil and gas properties.

Financial and Market Risks Applicable to Our Business

Natural gas, NGLs and oil prices are affected by a number of factors beyond our control, including many of which that are unknown and cannot be anticipated, and we cannot predict with certainty future potential movements in the price for these commodities.

Our primary business involves the exploration, production and sale of hydrocarbons, and in particular, natural gas. Consequently, our revenue, profitability, future rate of growth, liquidity and financial position depend upon the market prices for natural gas and, to a lesser extent, NGLs and oil. Because our production and reserves predominantly consist of natural gas (approximately 94% of our equivalent proved developed reserves), changes in natural gas prices have significantly greater impact on our financial results than oil prices.

The prices for natural gas, NGLs and oil have historically been volatile and have been particularly volatile in recent years. The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $9.85 per MMBtu to a low of $3.46 per MMBtu between the period from January 1, 2022 through December 31, 2022, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $123.64 per barrel to a low of $71.05 per barrel during the same period. 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. We expect commodity price volatility to continue or increase in the future due to rising macroeconomic uncertainty and geopolitical tensions, including the Russian invasion of Ukraine, which began in February 2022 and has put upward pressure on natural gas and oil prices.

Commodity 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 (the market price for natural gas in the Appalachian Basin is typically lower relative to NYMEX Henry Hub as a result of the increased production and supply of natural gas in the Northeast United States);
- national and worldwide economic and political conditions, particularly those in, or affecting, other countries which are significant producers of natural gas and/or oil;
- 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 consumer demand for 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;
- risks associated with drilling, completion and production operations; and
- domestic, local and foreign governmental regulations, tariffs and taxes, including environmental and climate change regulation.

We use financial models to attempt to project future prices for the hydrocarbons we produce and sell, and we make decisions regarding our production, operations and hedging strategy in part based on such modelling. However, due to the volatility of commodity prices and the multitude of external factors that impact commodity prices, many of which are unknown and unforeseeable, we are unable to predict with certainty future potential movements in the market prices for natural gas, NGLs and oil. The success of our plans and strategies could be negatively affected if our projections of future hydrocarbon prices are significantly different from the ultimate actual price.

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.

Prolonged low, and/or significant or extended declines in, natural gas, NGLs and oil prices may adversely affect our revenues, operating income, cash flows, financial projections, 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 debt or reduce our capital spending, which could reduce our production and our reserves, negatively affecting our future rate of growth. Reduced cash flows could also result in us having to make downward adjustments to our financial projections, such as free cash flow, and could cause us to revise our shareholder returns initiatives, including the amount of dividends paid on our common stock, which could negatively impact the price of our common stock and our ability to access the capital markets. 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 "Critical Accounting Policies and Estimates" included in Item 7., "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the Consolidated Financial Statements for a discussion of our accounting policies and significant assumptions related to accounting for natural gas, NGLs and oil producing activities and impairment of our oil and gas properties.

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 or letters of credit with our hedge counterparties and would negatively impact our liquidity. 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 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.

A financial crisis or deterioration in general economic, business or geopolitical conditions could materially adversely affect our operations and financial condition.

Concerns over global economic conditions, stock market volatility, energy costs, geopolitical issues (including continued hostilities between Russia and Ukraine), inflation and U.S. Federal Reserve interest rate increases in response thereto, the availability and cost of credit, and slowing of economic growth in the United States and abroad and fears of a recession have contributed and may continue to contribute to increased economic uncertainty and diminished expectations for the global economy. Global economic conditions, geopolitical issues and inflation have constrained global and domestic supply chains, which has impacted and could in the future continue to impact our ability to develop our reserves in accordance with our drilling and completions schedule. Additionally, global economic conditions have a significant impact on commodity prices and any stagnation or deterioration in global economic conditions could result in decreased demand and, thus, lower prices for natural gas, NGLs or oil. Such uncertainty could also result in higher natural gas, NGL and oil prices, which could potentially result in increased inflation worldwide and could negatively impact demand for natural gas, NGLs and oil.

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

In December 2021, we outlined a leverage and debt retirement strategy with the goal of retiring a significant amount of our total debt by the end of 2023 (our Debt Retirement Plan). We intend to fund our Debt Retirement Plan through free cash flow, and have aligned our hedge strategy in a manner that we believe will mitigate the risk of volatility of future natural gas and NGLs prices, which we anticipate will enable us to execute on our Debt Retirement Plan and other capital allocation strategies; however, there can be no assurance that we will be able to generate sufficient free cash flow to execute our Debt Retirement Plan on our anticipated timeframe, if at all. If we are not able to successfully execute our Debt Retirement Plan or otherwise reduce our total 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 our shareholder returns strategy or other 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 flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures, shareholder returns initiatives 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 flows 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, 2022, our senior notes were rated "Ba1" with a "positive" outlook by Moody's Investors Services (Moody's), "BBB-" with a "stable" outlook by Standard & Poor's Ratings Service (S&P) and "BBB-" with a "stable" 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 other factors 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 our Term Loan Facility (defined in Note 10 to the Consolidated Financial Statements) and senior notes with adjustable rates, 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, 2022, we had approximately $5.7 billion 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 us to comply 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.

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, and we may be required to post cash collateral or letters of credit with our hedge counterparties to the extent our liability under the derivative contract exceeds specified thresholds, which would negatively impact our liquidity. We have previously sustained losses as a result of certain of our derivative arrangements (including a $4.6 billion loss in 2022 and a $3.8 billion loss in 2021), and we cannot assure you that we will not do so in the future. 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 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.

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 and energy transition 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 energy infrastructure may adversely impact our operations.

Our business and the natural gas 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 or other security or physical threats, and the continuing armed conflict between Russia and Ukraine and associated economic sanctions on Russia may have increased the likelihood of such 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, in recent years, federal and state regulatory agencies have investigated the 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 volume 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 volume 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, due to regulatory and economic constraints, 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 Equitrans Midstream'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 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 Equitrans Midstream'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 Equitrans Midstream, including the following:

- federal, state and local regulatory, political and legal actions that could adversely affect Equitrans Midstream's and EQM's operations, assets and infrastructure, including potential further delays associated with obtaining regulatory approval for the construction of the Mountain Valley Pipeline;
- 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);
- cyber-attacks or acts of sabotage or terrorism that could cause significant damage or injury to Equitrans Midstream's personnel, assets or infrastructure or lead to extended interruptions of Equitrans Midstream's operations;
- risks associated with Equitrans Midstream failing to properly balance supply and demand for its services, on a short-term, seasonal and long-term basis, which could result in Equitrans Midstream 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 Equitrans Midstream's leverage and financial profile, which could result in Equitrans Midstream 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.

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 production possibly being 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.

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, in recent years several regulations at the federal and state level have been adopted, and more are being considered, to regulate the emission of carbon dioxide, methane and other GHGs.

In February 2021, the U.S. formally rejoined the Paris Agreement, an international treaty signed by nearly 200 counties which calls for countries to set their own GHG emissions targets and to be transparent about the measures they will implement to achieve their GHG emissions targets. In furtherance of the objectives of the Paris Agreement, in April 2021, the Biden Administration announced goals aimed at reducing the U.S.'s GHG emissions by 50-52% (compared to 2005 levels) by 2030. The federal government has correspondingly instituted several regulations and initiatives in alignment with the goal of reducing the U.S.'s GHG emissions. Most recently, at COP27, President Biden announced the EPA's proposed standards to reduce methane emissions from existing oil and gas sources, and agreed, in conjunction with the European Union and a number of other partner countries, to develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Various state and local governments have also publicly committed to furthering the goals of the Paris Agreement.

In June 2021, President Biden signed legislation reinstituting regulations which were previously repealed by the Trump Administration establishing NSPS for methane and VOC from new and modified oil and natural gas production and natural gas processing and transmission facilities. Additionally, 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. Furthermore, in November 2021, the EPA announced proposed rules expanding upon the NSPS rule which would establish standards for existing wells, impose more frequent and stringent leak monitoring, and mandate that all pneumatic controllers have zero emissions. On November 11, 2022, the EPA issued a proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to identify large emissions events, referred to in the proposed rule as "super emitters." The EPA is expected to issue a final rule by May 2023. These federal rulemakings and regulations could adversely affect our operations and restrict or delay our ability to obtain air permits.

In November 2021, Congress approved a $1 trillion legislative infrastructure package which includes a number of climate-focused spending initiatives targeted at climate resilience, enhanced response and preparation for extreme weather events, and clean energy and transportation investments. The Inflation Reduction Act also provides significant funding and incentives for research and development of low-carbon energy production methods, carbon capture, and other programs directed at addressing climate change, including imposing a fee on a facility's methane emissions in excess of a specified threshold.

At the state level, several states including Pennsylvania have proceeded with a number of state and regional efforts 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 RGGI, a multi-state regional cap-and-trade program comprised of several Eastern U.S. states. Pennsylvania became a member of RGGI in April 2022, though its membership is currently the subject of legal challenges. Depending on the outcome of such litigation, Pennsylvania's membership in RGGI will result in increased operating costs should we be required to purchase emission allowances in connection with our operations.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address methane and other GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or imposing a tax or fee or otherwise limiting emissions of methane or other GHGs from, our equipment and operations could require us to incur costs to comply with such regulations. Substantial limitations or taxes or fees on methane or other 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 some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts, and other extreme climatic events. If any such effects were to occur, they 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.

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 and occupational 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.

Members of Congress periodically introduce legislation to revise U.S. federal income tax laws which could have a material impact on us. Most recently, on August 16, 2022, legislation commonly known as the Inflation Reduction Act was signed into law. Among other things, the Inflation Reduction Act includes a 1% excise tax on corporate stock repurchases, applicable to repurchases made after December 31, 2022, and also a new minimum tax based on book income. We are in the process of evaluating the potential impacts of the Inflation Reduction Act to us. While we do not currently expect the Inflation Reduction Act to have a material impact on our financial statements, our analysis of the effect of the Inflation Reduction Act on us is ongoing and incomplete, and it is possible that the Inflation Reduction Act (or implementing regulations and other guidance) could adversely impact our current and deferred federal tax liability. Additionally, 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. As disclosed above in Item 1., "Business-Regulation," the Dodd-Frank Act, the rules adopted thereunder and various other 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, and 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 such 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 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 prohibits the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. Certain governmental reviews have been conducted or are underway that focus on the environmental aspects of hydraulic fracturing practices. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from constructing wells. See "Business-Regulation-Environmental, Health and Safety Regulation" for more information.

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

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment and occupational health and workplace safety, including regulations and enforcement policies that have tended to become increasingly strict over time, resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of clean-up 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 rule under the CWA defining the scope of the EPA's and the Corps' jurisdiction over WOTUS, which never took effect before being replaced by the NWPR in December 2019. A coalition of states and cities, environmental groups, and agricultural groups challenged the NWPR, which was vacated by a federal district court in August 2021. In addition, in an April 2020 decision further defining the scope of the CWA, 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 EPA is undergoing a rulemaking process to redefine the definition of WOTUS which could be impacted by the U.S. Supreme Court's pending decision in *Sackett v. EPA,* a case regarding the proper test in determining whether wetlands qualify as WOTUS. A final rule, known as "Rule 1" was announced by the EPA and the Corps in December 2022. The EPA and the Corps are expected to propose a second rule, known as "Rule 2," further refining Rule 1 by November 2023 and issue a final rule by July 2024. To the extent a new rule or further litigation 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, including threatened and endangered species and their critical habitat. The implementation of measures to protect wildlife or 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.

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.

Securities class action and derivative lawsuits may be brought against us in connection with strategic transactions, such as the Tug Hill and XcL Midstream Acquisition, which could result in substantial costs and may delay or prevent such transactions from being completed.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger or other business combination agreements. Even if such a lawsuit is without merit, defending against these claims can result in substantial costs and divert management time and resources. An adverse judgment could result in monetary damages, which could have a negative impact on our liquidity and financial condition. Lawsuits that may be brought against us or our or their directors could also seek, among other things, injunctive relief or other equitable relief, including a request to enjoin us from consummating the acquisition. One of the conditions to the closing of the Tug Hill and XcL Midstream Acquisition is that no court, tribunal or other governmental authority of competent jurisdiction has issued a final and non-appealable order, decree, judgment or law prohibiting the consummation of the Tug Hill and XcL Midstream Acquisition. Consequently, if a plaintiff is successful in obtaining an injunction prohibiting completion of the Tug Hill and XcL Midstream Acquisition, that injunction may delay or prevent the Tug Hill and XcL Midstream Acquisition from being completed within the expected timeframe or at all, which may adversely affect our business, financial position and results of operation.

Completion of the Tug Hill and XcL Midstream Acquisition is subject to conditions, including certain conditions that may not be satisfied or completed on a timely basis or at all. Failure to complete the Tug Hill and XcL Midstream Acquisition could have material and adverse effects on us.

Completion of the Tug Hill and XcL Midstream Acquisition is subject to a number of conditions, including, among other things, the termination or expiration of the applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Such conditions, some of which are beyond our control, may not be satisfied or waived in a timely manner or at all and therefore make the completion and timing of the completion of the Tug Hill and XcL Midstream Acquisition uncertain. In addition, the Tug Hill and XcL Midstream Purchase Agreement (defined in Note 6 to the Consolidated Financial Statements) contains certain termination rights for both us and the Sellers (defined in Note 6 to the Consolidated Financial Statements), which if exercised, will also result in the Tug Hill and XcL Midstream Acquisition not being consummated. Furthermore, the governmental authorities from which the regulatory approvals are required may impose conditions on the completion of the Tug Hill and XcL Midstream Acquisition or require changes to the terms thereof. Such conditions or changes and the process of obtaining regulatory approvals could have the effect of delaying or impeding consummation of the transactions or of imposing additional costs or limitations on us following completion of the Tug Hill and XcL Midstream Acquisition, any of which might have an adverse effect on us following completion of the Tug Hill and XcL Midstream Acquisition.

If the Tug Hill and XcL Midstream Acquisition is not completed, our ongoing business may be adversely affected and, without realizing any of the benefits of having completed the Tug Hill and XcL Midstream Acquisition, we will be subject to a number of risks, including the following:

- we will be required to pay our costs relating to the Tug Hill and XcL Midstream Acquisition, such as legal, accounting and financial advisory expenses, whether or not the transaction is completed;
- time and resources committed by our management to matters relating to the Tug Hill and XcL Midstream Acquisition could otherwise have been devoted to pursuing other beneficial opportunities; and
- the market price of our common stock could decline to the extent that the current market price reflects a market assumption that the Tug Hill and XcL Midstream Acquisition will be completed.

In addition to the above risks, if the Tug Hill and XcL Midstream Purchase Agreement is terminated and our Board of Directors seeks another acquisition, our shareholders cannot be certain that we will be able to find a party willing to enter into a transaction as attractive to us as the Tug Hill and XcL Midstream Acquisition. Also, if the Tug Hill and XcL Midstream Purchase Agreement is terminated under certain specified circumstances by the Sellers, the $150.0 million loan provided by us to the Upstream Seller (defined in Note 6 to the Consolidated Financial Statements), which would have been credited toward the cash consideration payable at the closing of the Tug Hill and XcL Midstream Acquisition, will be extinguished and we will not recover the principal or any interest thereunder.

We and the entities that we intend to acquire in the Tug Hill and XcL Midstream Acquisition (the Tug Hill and XcL Midstream Companies) will be subject to business uncertainties while the Tug Hill and XcL Midstream Acquisition is pending, which could adversely affect our business.

In connection with the pendency of the Tug Hill and XcL Midstream Acquisition, it is possible that certain persons with whom we or the Tug Hill and XcL Midstream Companies have a business relationship may delay or defer certain business decisions or might decide to seek to terminate, change or renegotiate their relationships with us or the Tug Hill and XcL Midstream Companies, as the case may be, as a result of the Tug Hill and XcL Midstream Acquisition, which could negatively affect our or the Tug Hill and XcL Midstream Companies' revenues, earnings and cash flows as well as the market price of our common stock, regardless of whether the Tug Hill and XcL Midstream Acquisition is completed. Also, our and the Tug Hill and XcL Midstream Companies' ability to attract, retain and motivate employees may be impaired until the Tug Hill and XcL Midstream Acquisition is completed, and our ability to do so may be impaired for a period of time thereafter, as current and prospective employees may experience uncertainty about their roles within the company following the Tug Hill and XcL Midstream Acquisition.

Under the terms of the Tug Hill and XcL Midstream Purchase Agreement, both we and the Tug Hill and XcL Midstream Companies are subject to certain restrictions on the conduct of business prior to the effective time of the Tug Hill and XcL Midstream Acquisition, which may adversely affect our and the Tug Hill and XcL Midstream Companies' ability to execute certain of our and their business strategies, including the ability in certain cases to modify or enter into certain contracts, acquire or dispose of certain assets, incur or prepay certain indebtedness, incur encumbrances, make capital expenditures or settle claims. Such limitations could negatively affect our and the Tug Hill and XcL Midstream Companies' businesses and operations prior to the completion of the Tug Hill and XcL Midstream Acquisition.

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. In particular, if the Tug Hill and XcL Midstream Acquisition is consummated, we may be unable to successfully integrate the acquired assets into our business or achieve the anticipated benefits of the Tug Hill and XcL Midstream Acquisition.

Successful property acquisitions, including assets we intend to acquire in the Tug Hill and XcL Midstream Acquisition, 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 and their appropriate differentials; availability and cost of transportation of production to markets; availability and cost of drilling equipment and of skilled personnel; development and operating costs, including access to water; production taxes; potential environmental and other liabilities; and regulatory, permitting and similar matters. 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. In connection with our assessment of the assets of the Upstream Seller, we have performed a review of the subject properties that we believe to be generally consistent with industry practices. The review was based on our analysis of historical production data, assumptions regarding capital expenditures and anticipated production declines without review by an independent petroleum engineering firm. Data used in such review was furnished by the Sellers or obtained from publicly available sources. Our review may not reveal all existing or potential problems or permit us to fully assess the deficiencies and potential recoverable reserves for all of the Upstream Seller's assets, and the reserves and production related to the Upstream Seller's assets may differ materially after such data is reviewed by an independent petroleum engineering firm or further by us. Inspections were not performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken.

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.

Also, our ability to achieve the anticipated benefits of an acquisition, including the Tug Hill and XcL Midstream Acquisition, will depend in part upon whether we can integrate the acquired assets and their operations into our existing business in an efficient and effective manner. The integration process may be subject to delays or changed circumstances, and we can give no assurance that acquired assets will perform in accordance with our expectations or that our expectations with respect to integration or cost savings as a result of an acquisition, such as the Tug Hill and XcL Midstream Acquisition, will materialize.

We will incur significant transaction costs in connection with the Tug Hill and XcL Midstream Acquisition.

We have incurred, and are expected to continue to incur, a number of non-recurring costs associated with the Tug Hill and XcL Midstream Acquisition, combining the operations of the acquired assets with ours and achieving desired synergies. These costs have been, and will continue to be, substantial and, in many cases, will be borne by us whether or not the Tug Hill and XcL Midstream Acquisition is completed. A substantial majority of non-recurring expenses will consist of transaction costs and include, among others, fees paid to financial, legal, accounting and other advisors and employee retention, severance and benefit costs. We will also incur costs related to formulating and implementing integration plans. Although we expect that the elimination of duplicative costs, as well as the realization of synergies and efficiencies related to the integration of the acquired assets, should allow us to offset these transaction costs over time, this net benefit may not be achieved in the near term or at all.

If there is a later determination that our spin-off of Equitrans Midstream 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 our 2018 spin-off of Equitrans Midstream as a separate, publicly-traded company, we obtained a private letter ruling from the IRS and an opinion of outside counsel regarding the qualification of the distribution of Equitrans Midstream shares to our shareholders (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 spin-off-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 spin-off, we and Equitrans Midstream entered into a tax matters agreement, which described the sharing of any such liabilities between us and Equitrans Midstream.

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 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 pending matter involving us will not materially affect our financial position, results of operations or liquidity.

Environmental Proceedings

Produced Water Release, Washington County, Pennsylvania. In December 2021, we discovered a produced water leak associated with a Gas Processing Unit (GPU) disposal line at one of our well pad sites located in Washington County, Pennsylvania. We self-reported the release to the PADEP spill hotline on December 4, 2021 and initiated cleanup of the released produced water. The initial release was determined to be in excess of one barrel and we entered the remediation project into PADEP's Land Recycling and Environmental Remediation Act 2 Program (Act 2) for voluntary cleanup. In January 2022, we determined the release was larger than initially discovered and we disclosed this information to PADEP on January 14,

2022. Site characterization of the release is ongoing and upon completion, we intend to initiate the remediation according to PADEP's Act 2 guidelines. While we anticipate that the penalties related to this matter will exceed $300,000, we expect that the resolution of this matter will not have a material impact on our financial condition, 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 January 18, 2023, the Circuit Court of Doddridge County, West Virginia granted an Order to dismiss this case and all corresponding claims, counterclaims, and pending motions. Accordingly, this matter is now closed.

Item 4. Mine Safety Disclosures

Not Applicable.

Information about our Executive Officers (as of February 16, 2023)

Name and Age	Current Title (Year Initially Elected an Executive Officer)	Business Experience
Tony Duran (44)	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 (45)	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 (40)	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 (42)	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 (59)	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 (41)	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 appointed 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 10, 2023, there were 1,820 shareholders of record of our common stock.

On February 9, 2023, our Board of Directors declared a quarterly cash dividend of $0.15 per share, payable on March 1, 2023, to shareholders of record at the close of business on February 21, 2023.

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 dividend rate at any time for any reason.

Recent Sales of Unregistered Securities

The following table sets forth our repurchases of equity securities registered under Section 12 of the Exchange Act that have occurred during the three months ended December 31, 2022.

	Total number of shares purchased (a)	Average price paid per share (b)	Total number of shares purchased as part of publicly announced plans or programs (c)	Approximate dollar value of shares that may yet be purchased under plans or programs (c)
October 1, 2022 – October 31, 2022	1,880,073	$ 41.48	1,880,073	$ 1,617,803,090
November 1, 2022 – November 30, 2022	958,327	41.66	958,327	1,577,882,777
December 1, 2022 – December 31, 2022	12,168	41.08	—	1,577,882,777
Total	2,850,568		2,838,400	

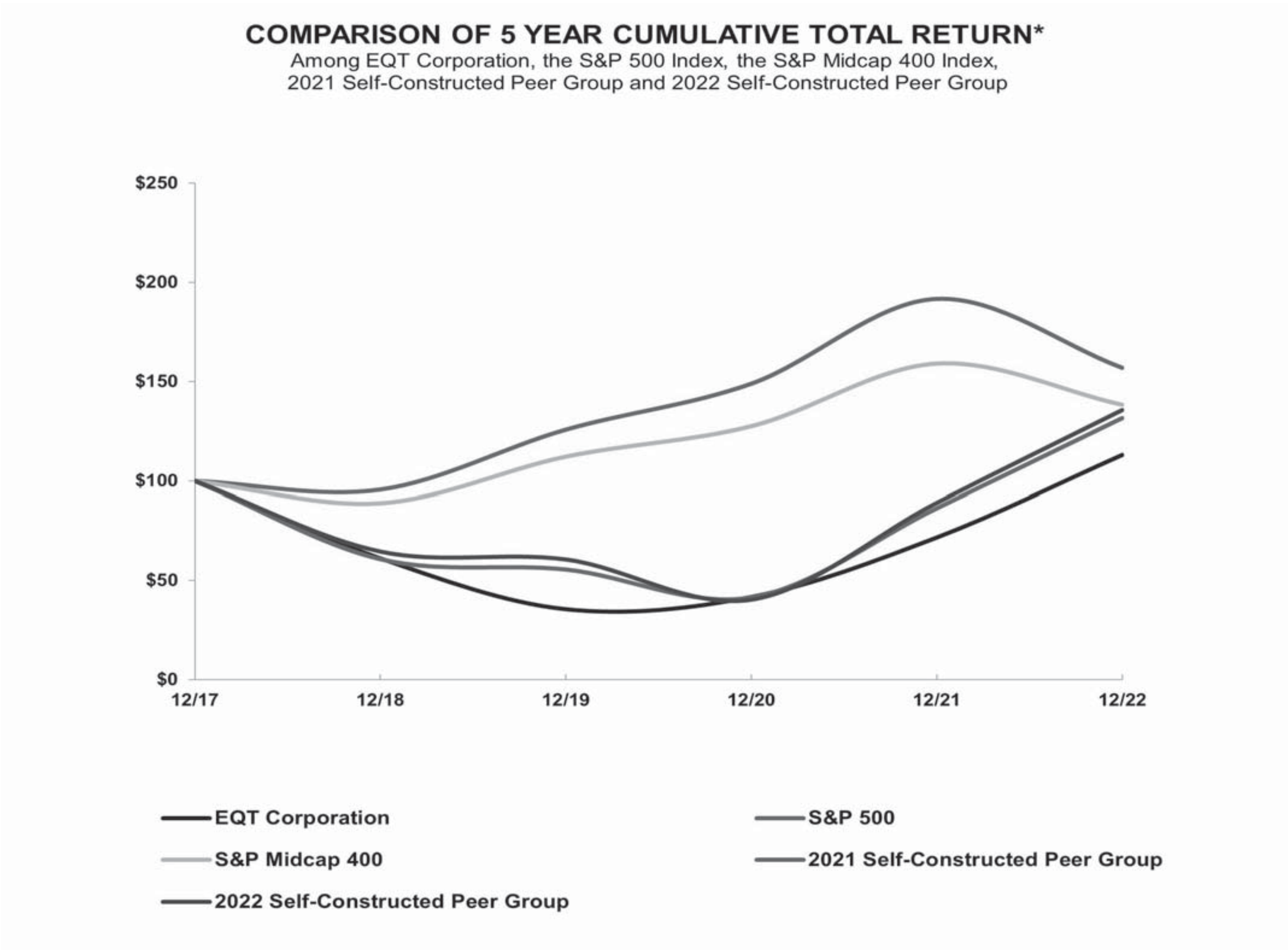
(a) In December 2022, we withheld 12,168 shares to pay taxes upon vesting of restricted stock. There were no shares withheld to pay taxes upon vesting of restricted stock in October and November 2022.

(b) Excludes any fees, commissions or other expenses associated with the share repurchases.

(c) On December 13, 2021, we announced that our Board of Directors approved a share repurchase program to repurchase shares of our outstanding common stock for an aggregate purchase price up to $1 billion, excluding fees, commissions and expenses. On September 6, 2022, we announced that our Board of Directors approved a $1 billion increase to the share repurchase program announced on December 13, 2021, pursuant to which approval we are authorized to repurchase shares of our outstanding common stock for an aggregate purchase price of up to $2 billion, excluding fees, commissions and expenses. Repurchases under the share repurchase program may be made from time to time in amounts and at prices we deem appropriate and will be subject to a variety of factors, including the market price of our common stock, general market and economic conditions, applicable legal requirements and other considerations. The share repurchase program expires December 31, 2023 but may be suspended, modified or discontinued at any time without prior notice. As of December 31, 2022, we had purchased shares for an aggregate purchase price of $422.1 million, excluding fees, commissions and expenses, under this authorization since its inception. The total number of shares purchased and the approximate dollar value of shares that may yet be purchased under our repurchase authority reported in this table reflect shares purchased in each month based on the trade date; however, certain purchases may not have settled until the following month.

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 S&P 500 Index, the S&P MidCap 400 Index and two customized peer groups, the 2021 Self-Constructed Peer Group and 2022 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 November 2018, at which time our common stock was added to the S&P MidCap 400 Index. Our common stock was added back to the S&P 500 Index in October 2022. Accordingly, 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, 2017 and its relative performance is tracked through December 31, 2022. Historical prices prior to November 2018 have been adjusted to reflect the spin-off of our midstream business in 2018. The stock price performance shown in the graph below is not necessarily indicative of future stock price performance.



*$100 invested on 12/31/17 in stock, index, or peer group, including reinvestment of dividends.

	12/17	12/18	12/19	12/20	12/21	12/22
EQT Corporation	$ 100.00	$ 61.28	$ 35.65	$ 41.80	$ 71.73	$ 113.04
S&P 500 Index	100.00	95.62	125.72	148.85	191.58	156.89
S&P MidCap 400 Index	100.00	88.92	112.21	127.54	159.12	138.34
2021 Self-Constructed Peer Group (a)	100.00	60.74	55.53	41.45	86.27	131.48
2022 Self-Constructed Peer Group (b)	100.00	64.68	60.70	40.46	89.07	135.60

(a) The 2021 Self-Constructed Peer Group includes the following ten companies: Antero Resources Corp., Apache Corp., CNX Resources Corp., Comstock Resources, Inc., Coterra Energy Inc., Devon Energy Corp., Murphy Oil Corp., Ovintiv Inc., Range Resources Corp. and Southwestern Energy Co. The 2021 Self-Constructed Peer Group is comprised of the companies included in our 2021 performance peer group (with the exception of (i) Cimarex Energy Co., which was excluded for purposes of the stock performance graph because it was acquired by Cabot Oil & Gas Corp. in October 2021 thereby forming Coterra Energy Inc, and (ii) Continental Resources, Inc., which was excluded for purposes of the stock performance graph because its stock ceased to be publicly traded beginning in November 2022), as selected by the Management Development and Compensation Committee of our Board of Directors for purposes of evaluating our relative total shareholder return under the 2021 Incentive Performance Share Unit Program.

(b) The 2022 Self-Constructed Peer Group includes the following fifteen companies: Antero Resources Corp., Apache Corp., Chesapeake Energy Corp., CNX Resources Corp., Comstock Resources, Inc., Coterra Energy Inc., Devon Energy Corp., Diamondback Energy Corp., Marathon Oil Corp., Matador Resources Co., Murphy Oil Corp., Ovintiv Inc., PDC Energy Inc., Range Resources Corp. and Southwestern Energy Co. The 2022 Self-Constructed Peer Group is comprised of the companies included in our 2022 performance peer group (with the exception of Continental Resources, Inc., which was excluded for purposes of the stock performance graph because its stock ceased to be publicly traded beginning in November 2022), as selected by the Management Development and Compensation Committee of our Board of Directors for purposes of evaluating our relative total shareholder return under the 2022 Incentive Performance Share Unit Program.

Item 6. [Reserved]

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 income attributable to EQT Corporation for 2022 was $1,771 million, $4.38 per diluted share, compared to net loss attributable to EQT Corporation for 2021 of $1,143 million, $3.54 per diluted share. The change was attributable primarily to increased sales of natural gas, NGLs and oil, partly offset by income tax expense, greater loss on derivatives, the impairment of our contract asset (discussed in Note 5 to the Consolidated Financial Statements), increased transportation and processing expense and increased loss on debt extinguishment.

Net loss attributable to EQT Corporation for 2021 was $1,143 million, $3.54 per diluted share, compared to net loss attributable to EQT Corporation for 2020 of $959 million, $3.68 per diluted share. The change was attributable primarily to the loss on derivatives, increased depreciation and depletion, increased transportation and processing and the gain on the Equitrans Share Exchange (defined and discussed in Note 5 to the Consolidated Financial Statements) recognized in 2020, partly offset by increased sales of natural gas, NGLs and oil, the income from investments, higher income tax benefit and the gain on sale/exchange of long-lived assets.

Results of operations for 2022 and for the period beginning July 21, 2021 and ending December 31, 2021 include the results of our operation of assets acquired in the Alta Acquisition. See Note 6 to the Consolidated Financial Statements for further discussion.

See "Sales Volume 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.

Trends and Uncertainties

Our sales volume and operating expenses for 2022 were negatively impacted by fewer wells turned-in-line and adjustments to our planned development schedule as a result of third-party supply chain constraints. Strong underlying well performance and field optimization helped mitigate the impacts to 2022 sales volume; however, supply chain constraints may continue to impact our future sales volume, operating revenues and expenses, per unit metrics and capital expenditures.

The annual inflation rate in the United States was particularly high during 2022, and many analysts anticipate inflation will remain elevated through 2023. Inflationary pressures have multiple impacts on our business, including increasing our operating expenses and our cost of capital. Furthermore, certain of our commitments for demand charges under our existing long-term contracts and processing capacity are subject to consumer price index adjustments. Although we believe our scale and supply chain contracting strategy of using multi-year sand and frac crew contracts allows us to maximize capital and operating efficiencies, future increases in the inflation rate will negatively impact our long-term contracts with consumer price index adjustments.

Additionally, while the prices for natural gas, NGLs and oil have historically been volatile, price volatility was especially pronounced during 2022. The daily spot prices for NYMEX Henry Hub natural gas ranged from a high of $9.85 per MMBtu to a low of $3.46 per MMBtu between the period from January 1, 2022 through December 31, 2022, and the daily spot prices for NYMEX West Texas Intermediate crude oil ranged from a high of $123.64 per barrel to a low of $71.05 per barrel during the same period. We expect commodity price volatility to continue or increase throughout 2023 due to rising macroeconomic uncertainty and geopolitical tensions, including the Russian invasion of Ukraine, which began in February 2022 and has put upward pressure on natural gas and oil prices. Our revenue, profitability, rate of growth, liquidity and financial position will continue to be impacted in the future by the market prices for natural gas and, to a lesser extent, NGLs and oil.

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 ($/Mcfe), which is based on adjusted operating revenues, a non-GAAP supplemental financial measure. Adjusted operating revenues is presented because it is an important measure 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,		
	2022	2021	2020
	(Thousands, unless otherwise noted)		
NATURAL GAS			
Sales volume (MMcf)	1,842,044	1,746,317	1,418,774
NYMEX price ($/MMBtu)	$ 6.64	$ 3.97	$ 2.09
Btu uplift	0.35	0.20	0.11
Natural gas price ($/Mcf)	$ 6.99	$ 4.17	$ 2.20
Basis ($/Mcf) (a)	$ (0.77)	$ (0.63)	$ (0.47)
Cash settled basis swaps ($/Mcf)	(0.02)	(0.07)	0.05
Average differential, including cash settled basis swaps ($/Mcf)	$ (0.79)	$ (0.70)	$ (0.42)
Average adjusted price ($/Mcf)	$ 6.20	$ 3.47	$ 1.78
Cash settled derivatives ($/Mcf)	(3.20)	(1.09)	0.59
Average natural gas price, including cash settled derivatives ($/Mcf)	$ 3.00	$ 2.38	$ 2.37
Natural gas sales, including cash settled derivatives	$ 5,529,963	$ 4,153,221	$ 3,359,583
LIQUIDS			
NGLs, excluding ethane:			
Sales volume (MMcfe) (b)	56,735	64,202	44,702
Sales volume (Mbbl)	9,456	10,700	7,451
NGLs price ($/Bbl)	$ 53.26	$ 44.50	$ 20.51
Cash settled derivatives ($/Bbl)	(3.91)	(12.32)	(0.12)
Average NGLs price, including cash settled derivatives ($/Bbl)	$ 49.35	$ 32.18	$ 20.39
NGLs sales, including cash settled derivatives	$ 466,664	$ 344,260	$ 151,877
Ethane:			
Sales volume (MMcfe) (b)	35,100	37,548	29,489
Sales volume (Mbbl)	5,850	6,258	4,914
Ethane price ($/Bbl)	$ 14.20	$ 8.85	$ 3.48
Ethane sales	$ 83,096	$ 55,393	$ 17,085
Oil:			
Sales volume (MMcfe) (b)	6,164	9,750	4,827
Sales volume (Mbbl)	1,027	1,625	804
Oil price ($/Bbl)	$ 77.06	$ 56.82	$ 25.57
Oil sales	$ 79,160	$ 92,334	$ 20,574
Total liquids sales volume (MMcfe) (b)	97,999	111,500	79,018
Total liquids sales volume (Mbbl)	16,333	18,583	13,169
Total liquids sales	$ 628,920	$ 491,987	$ 189,536
TOTAL			
Total natural gas and liquids sales, including cash settled derivatives (c)	$ 6,158,883	$ 4,645,208	$ 3,549,119
Total sales volume (MMcfe)	1,940,043	1,857,817	1,497,792
Average realized price ($/Mcfe)	$ 3.17	$ 2.50	$ 2.37

(a) Basis represents the difference between the ultimate sales price for natural gas, including the effects of delivered price benefit or deficit associated with our firm transportation agreements, and the NYMEX natural gas price.

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

(c) 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 consists of the costs of, and recoveries on, pipeline capacity releases, revenues for gathering services provided to third parties and other revenues. 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,		
	2022	2021	2020
	(Thousands, unless otherwise noted)		
Total operating revenues	$ 7,497,689	$ 3,064,663	$ 3,058,843
Add (deduct):			
Loss (gain) on derivatives	4,642,932	3,775,042	(400,214)
Net cash settlements (paid) received on derivatives	(5,927,698)	(2,091,003)	897,190
Premiums (paid) received for derivatives that settled during the period	(27,587)	(67,809)	1,630
Net marketing services and other	(26,453)	(35,685)	(8,330)
Adjusted operating revenues, a non-GAAP financial measure	$ 6,158,883	$ 4,645,208	$ 3,549,119
Total sales volume (MMcfe)	1,940,043	1,857,817	1,497,792
Average realized price ($/Mcfe)	$ 3.17	$ 2.50	$ 2.37

Sales Volume and Revenues

	Years Ended December 31,			
	2022	2021	Change	% Change
	(Thousands, unless otherwise noted)			
Sales volume by shale (MMcfe):				
Marcellus	1,809,049	1,684,673	124,376	7.4
Ohio Utica	123,517	163,775	(40,258)	(24.6)
Other	7,477	9,369	(1,892)	(20.2)
Total sales volume	1,940,043	1,857,817	82,226	4.4
Average daily sales volume (MMcfe/d)	5,315	5,090	225	4.4
Operating revenues:				
Sales of natural gas, NGLs and oil	$ 12,114,168	$ 6,804,020	$ 5,310,148	78.0
Loss on derivatives	(4,642,932)	(3,775,042)	(867,890)	23.0
Net marketing services and other	26,453	35,685	(9,232)	(25.9)
Total operating revenues	$ 7,497,689	$ 3,064,663	$ 4,433,026	144.6

Sales of natural gas, NGLs and oil. Sales of natural gas, NGLs and oil increased for 2022 compared to 2021 due to a higher average realized price and increased sales volume.

Average realized price for 2022 compared to 2021 increased due to higher NYMEX prices and higher liquids prices, partly offset by unfavorable cash settled derivatives and unfavorable differential. For 2022 and 2021, we paid $5,927.7 million and $2,091.0 million, respectively, of net cash settlements on derivatives, which are included in average realized price but may not be included in operating revenues.

Sales volume increased primarily as a result of sales volume increases from the assets acquired in the Alta Acquisition, partly offset by natural decline of producing wells and fewer wells turned-in-line. Sales volume for 2022 was negatively impacted by fewer wells turned-in-line as a result of third-party supply chain constraints. Supply chain constraints and inflationary pressures may continue to impact our future operating revenues. The assets which we intend to acquire in the pending Tug Hill and XcL Midstream Acquisition, which is subject to regulatory approvals, are currently producing approximately 800 MMcfe per day of sales volume, 20% of which is liquids sales volume.

Loss on derivatives. For 2022 and 2021, we recognized a loss on derivatives of $4,642.9 million and $3,775.0 million, respectively, related primarily to decreases in the fair market value of our NYMEX swaps and options due to increases in NYMEX forward prices.

Net marketing services and other. Net marketing services and other decreased for 2022 compared to 2021 due primarily to a decrease in the liquids uplift realized on gas purchased at the wellhead from other operators, partly offset by an increase in third-party gathering revenues recognized on the midstream assets acquired in the Alta Acquisition.

	Years Ended December 31,			
	2021	2020	Change	% Change
	(Thousands, unless otherwise noted)			
Sales volume by shale (MMcfe):				
Marcellus	1,684,673	1,314,801	369,872	28.1
Ohio Utica	163,775	177,864	(14,089)	(7.9)
Other	9,369	5,127	4,242	82.7
Total sales volume	1,857,817	1,497,792	360,025	24.0
Average daily sales volume (MMcfe/d)	5,090	4,092	998	24.4
Operating revenues:				
Sales of natural gas, NGLs and oil	$ 6,804,020	$ 2,650,299	$ 4,153,721	156.7
(Loss) gain on derivatives	(3,775,042)	400,214	(4,175,256)	(1,043.3)
Net marketing services and other	35,685	8,330	27,355	328.4
Total operating revenues	$ 3,064,663	$ 3,058,843	$ 5,820	0.2

Sales of natural gas, NGLs and oil. Sales of natural gas, NGLs and oil increased for 2021 compared to 2020 due to increased sales volume and a higher average realized price.

Sales volume increased primarily as a result of sales volume increases of 170 Bcfe from the assets acquired in the Alta Acquisition, sales volume increases of 127 Bcfe from the assets acquired in the Chevron Acquisition (defined in Note 6 to the Consolidated Financial Statements), prior year sales volume decreases of 46 Bcfe from the 2020 Strategic Production Curtailments and sales volume increases as a result of the Reliance Asset Acquisition (defined in Note 6 to the Consolidated Financial Statements) and from wells turned in-line during 2021, partly offset by sales volume decreases of 9 Bcfe from the 2020 Divestiture (defined in Note 8 to the Consolidated Financial Statements).

The 2020 Strategic Production Curtailments refers to our strategic decisions to temporarily curtail certain 2020 production. In May 2020, we temporarily curtailed approximately 1.4 Bcf per day of gross production, equivalent to approximately 1.0 Bcf per day of net production. In July 2020, we began a moderated approach to bring back on-line the curtailed production. In September 2020, we curtailed approximately 0.6 Bcf per day of gross production, equivalent to approximately 0.4 Bcf per day of net production. In October 2020, we began a phased approach to bring back on-line the curtailed production, which was completed in November 2020.

Average realized price increased due to higher NYMEX prices and higher liquids prices, partly offset by lower cash settled derivatives and unfavorable differential. For 2021 and 2020, we paid $2,091.0 million and received $897.2 million, respectively, of net cash settlements on derivatives, which are included in average realized price but may not be included in operating revenues.

(Loss) gain on derivatives. For 2021 and 2020, we recognized a loss of $3,775.0 million and a gain of $400.2 million, respectively, on derivatives. The loss for 2021 was related primarily to decreases in the fair market value of our NYMEX swaps and options due to increases in NYMEX forward prices. The gain for 2020 was related primarily to increases in the fair market value of our NYMEX swaps and options due to decreases in NYMEX forward prices.

Net marketing services and other. Net marketing services and other increased for 2021 compared to 2020 due primarily to the liquids uplift realized on gas purchased at the wellhead from other operators and third-party gathering revenues recognized on the midstream assets acquired in the Alta Acquisition.

Operating Expenses

	Years Ended December 31,			
	2022	**2021**	**Change**	**% Change**
	(Thousands, unless otherwise noted)			
Operating expenses:				
Gathering	$ 1,316,213	$ 1,228,153	$ 88,060	7.2
Transmission	601,497	525,811	75,686	14.4
Processing	199,266	188,201	11,065	5.9
Lease operating expenses (LOE)	156,523	126,640	29,883	23.6
Production taxes	144,462	98,639	45,823	46.5
Exploration	3,438	24,403	(20,965)	(85.9)
Selling, general and administrative	252,645	196,315	56,330	28.7
Production depletion	$ 1,644,625	$ 1,658,113	$ (13,488)	(0.8)
Other depreciation and depletion	21,337	18,589	2,748	14.8
Total depreciation and depletion	$ 1,665,962	$ 1,676,702	$ (10,740)	(0.6)
Per Unit ($/Mcfe):				
Gathering	$ 0.68	$ 0.66	$ 0.02	3.0
Transmission	0.31	0.28	0.03	10.7
Processing	0.10	0.10	—	—
LOE	0.08	0.07	0.01	14.3
Production taxes	0.07	0.05	0.02	40.0
Exploration	—	0.01	(0.01)	(100.0)
Selling, general and administrative	0.13	0.11	0.02	18.2
Production depletion	0.85	0.89	(0.04)	(4.5)

Gathering. Gathering expense increased on an absolute basis for 2022 compared to 2021 due primarily to increased sales volume from the assets acquired in the Alta Acquisition and higher gathering rates on certain contracts indexed to price, partly offset by lower expense as a result of less utilization of lower overrun rates as part of the Consolidated GGA (defined and discussed in Note 5 to the Consolidated Financial Statements) due to the natural decline of producing wells and fewer wells turned-in-line. Gathering expense increased on a per Mcfe basis for 2022 compared to 2021 due primarily to higher gathering rates on certain contracts indexed to price and less utilization of lower overrun rates as part of the Consolidated GGA due to the natural decline of producing wells and fewer wells turned-in-line, partly offset by the lower gathering rate structure on the assets acquired in the Alta Acquisition.

Transmission. Transmission expense increased on an absolute and per Mcfe basis for 2022 compared to 2021 due primarily to higher rates on and lower credits received from the Texas Eastern Transmission Pipeline, additional capacity acquired in the Alta Acquisition and additional capacity acquired on the Rockies Express Pipeline in September 2021.

Processing. Processing expense increased on an absolute basis for 2022 compared to 2021 due to increased volumes that require processing as a result of increased development of liquids-rich areas.

LOE. LOE increased on an absolute and per Mcfe basis for 2022 compared to 2021 due primarily to additional lease operating costs as a result of the Alta Acquisition and higher salt water disposal costs.

Production taxes. Production taxes increased on an absolute and per Mcfe basis for 2022 compared to 2021 due to increased West Virginia severance taxes, which resulted primarily from higher prices, and increased Pennsylvania impact fees, which resulted from additional wells spud in 2022, including those acquired in the Alta Acquisition, higher prices and inflation.

Exploration. Exploration expense decreased on an absolute and per Mcfe basis for 2022 compared to 2021 due primarily to our purchase of seismic data in 2021 following the completion of the Alta Acquisition.

Selling, general and administrative. Selling, general and administrative expense increased on an absolute and per Mcfe basis for 2022 compared to 2021 due primarily to higher long-term incentive compensation costs as a result of changes in the fair value of awards and increased labor costs driven by an increase in the number of our total permanent employees. Long-term incentive compensation may fluctuate with changes in our stock price and performance conditions.

Depreciation and depletion. Production depletion expense decreased on an absolute and per Mcfe basis for 2022 compared to 2021 due to a lower annual depletion rate.

(Gain) loss/impairment on sale/exchange of long-lived assets. During 2022 and 2021, we recognized a gain on sale/exchange of long-lived assets of $8.4 million and $21.1 million, respectively, related primarily to changes in the fair value of the Contingent Consideration (defined and discussed in Note 8 to the Consolidated Financial Statements) from the 2020 Divestiture.

Impairment of contract and other assets. During 2022, we recognized impairment of our contract asset of $214.2 million as discussed in Note 5 to the Consolidated Financial Statements.

Impairment and expiration of leases. During 2022 and 2021, we recognized impairment and expiration of leases of $176.6 million and $311.8 million, respectively, related to impairment and expiration of leases that we no longer expect to develop based on our development plan.

Other operating expenses. Other operating expenses for 2022 of $57.3 million were attributable primarily to changes in legal and environmental reserves including settlements as well as transaction costs associated with the Tug Hill and XcL Midstream Acquisition. Other operating expenses for 2021 of $70.1 million were attributable primarily to transaction costs associated with the Alta Acquisition and Chevron Acquisition. See Note 1 to the Consolidated Financial Statements for a summary of other operating expenses.

	Years Ended December 31,			
	2021	2020	Change	% Change
	(Thousands, unless otherwise noted)			
Operating expenses:				
Gathering	$ 1,228,153	$ 1,068,590	$ 159,563	14.9
Transmission	525,811	506,668	19,143	3.8
Processing	188,201	135,476	52,725	38.9
LOE	126,640	109,027	17,613	16.2
Production taxes	98,639	46,376	52,263	112.7
Exploration	24,403	5,484	18,919	345.0
Selling, general and administrative	196,315	174,769	21,546	12.3
Production depletion	$ 1,658,113	$ 1,375,542	$ 282,571	20.5
Other depreciation and depletion	18,589	17,923	666	3.7
Total depreciation and depletion	$ 1,676,702	$ 1,393,465	$ 283,237	20.3
Per Unit ($/Mcfe):				
Gathering	$ 0.66	$ 0.71	$ (0.05)	(7.0)
Transmission	0.28	0.34	(0.06)	(17.6)
Processing	0.10	0.09	0.01	11.1
LOE	0.07	0.07	—	—
Production taxes	0.05	0.03	0.02	66.7
Exploration	0.01	—	0.01	100.0
Selling, general and administrative	0.11	0.12	(0.01)	(8.3)
Production depletion	0.89	0.92	(0.03)	(3.3)

Gathering. Gathering expense increased on an absolute basis for 2021 compared to 2020 due to increased sales volume. Gathering expense decreased on a per Mcfe basis for 2021 compared to 2020 due primarily to the lower gathering rate structures on the assets acquired in the Chevron Acquisition and Alta Acquisition and increased sales volume, which resulted in our utilization of lower overrun rates as part of the Consolidated GGA (defined and discussed in Note 5 to the Consolidated Financial Statements).

Transmission. Transmission expense increased on an absolute basis for 2021 compared to 2020 due primarily to additional capacity acquired as part of the Alta Acquisition. Transmission expense decreased on a per Mcfe basis for 2021 compared to 2020 due primarily to increased sales volume from the Chevron Acquisition and Alta Acquisition, which have a lower average transmission expense per Mcfe when compared to our historical transmission portfolio.

Processing. Processing expense increased on an absolute and per Mcfe basis for 2021 compared to 2020 due to increased liquid sales volume as a result of increased development of liquids-rich areas and increased processed volume from the Chevron Acquisition.

LOE. LOE increased on an absolute basis for 2021 compared to 2020 due primarily to additional lease operating costs as a result of the Alta Acquisition and Chevron Acquisition.

Production taxes. Production taxes increased on an absolute and per Mcfe basis for 2021 compared to 2020 due to increased West Virginia severance taxes, which resulted primarily from higher prices, and increased Pennsylvania impact fees, which resulted from higher prices and additional wells acquired in the Alta Acquisition and Chevron Acquisition.

Exploration. Exploration expense increased on an absolute and per Mcfe basis for 2021 compared to 2020 due primarily to our purchase of seismic data following the completion of the Alta Acquisition.

Selling, general and administrative. Selling, general and administrative expense increased on an absolute basis for 2021 compared to 2020 due primarily to higher long-term incentive compensation costs as a result of changes in the fair value of awards as well as higher litigation expense. Selling, general and administrative expense decreased on a per Mcfe basis for 2021 compared to 2020 due primarily to increased sales volumes and nominal incremental selling, general and administrative spend with respect to the Alta Acquisition and Chevron Acquisition.

Depreciation and depletion. Production depletion expense increased on an absolute basis for 2021 compared to 2020 due to increased sales volume, partly offset by a lower annual depletion rate. Production depletion expense decreased on a per Mcfe basis for 2021 compared to 2020 due to a lower annual depletion rate.

Amortization of intangible assets. Amortization of intangible assets for 2020 was $26.0 million. Our intangible assets were fully amortized in November 2020.

(Gain) loss/impairment on sale/exchange of long-lived assets. During 2021, we recognized a gain on sale/exchange of long-lived assets of $21.1 million related primarily to changes in the fair value of the Contingent Consideration from the 2020 Divestiture. 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 7 to the Consolidated Financial Statements) and $39.1 million related to asset sales, including the 2020 Divestiture.

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 of our non-operating receivables as a result of expected credit losses.

Impairment and expiration of leases. During 2021 and 2020, we recognized impairment and expiration of leases of $311.8 million and $306.7 million, respectively, related to impairment and expiration of leases that we no longer expect to develop based on our development strategy.

Other operating expenses. Other operating expenses for 2021 of $70.1 million were attributable primarily to transaction costs associated with the Alta Acquisition and Chevron Acquisition. Other operating expenses for 2020 of $28.5 million were attributable primarily to transactions, changes in legal reserves, including settlements, and reorganization. See Note 1 to the Consolidated Financial Statements for a summary of other operating expenses.

Other Income Statement Items

Gain on Equitrans Share Exchange. During the first quarter of 2020, we recognized a gain on the Equitrans Share Exchange of $187.2 million. See Note 5 to the Consolidated Financial Statements.

Loss (income) from investments. For 2022, we recognized a loss from investments due to a loss on the sale of our investment in Equitrans Midstream, which resulted from a decrease in Equitrans Midstream's stock price to $8.65 as of April 20, 2022, the date of the final sale of our investment, from $10.34 as of December 31, 2021, partly offset by equity earnings on our equity method investments and a gain on our investment in the Investment Fund (defined and discussed in Note 1 to the Consolidated Financial Statements). For 2021, we recognized income from investments due to a gain on our investment in Equitrans Midstream, equity earnings on our equity method investments and a gain on our investment in the Investment Fund. For 2020, we recognized a loss from investments due to a loss on our investment in Equitrans Midstream.

Dividend and other income. Dividend and other income decreased for 2022 compared to 2021 due primarily to lower dividends received on our investment in Equitrans Midstream, which was fully disposed in April 2022, partly offset by higher dividends received on our investment in the Investment Fund. Dividend and other income decreased for 2021 compared to 2020 due primarily to lower dividends received from our investment in Equitrans Midstream driven by a decrease in the number of shares of Equitrans Midstream's common stock that we owned as well as a decrease in the dividend amount per share.

Loss on debt extinguishment. During 2022, 2021 and 2020, we recognized a loss on debt extinguishment due to the debt repayments and repurchases discussed in Note 10 to the Consolidated Financial Statements.

Interest expense. Interest expense decreased for 2022 compared to 2021 due primarily to reduced interest expense on our senior notes driven by lower balances and lower interest rates, reduced interest expense due to a reduction of letters of credit balances and higher interest income. Interest expense increased for 2021 compared to 2020 due to increased interest incurred on new debt related to the Chevron Acquisition and Alta Acquisition and higher periodic borrowings under our credit facility. See Note 10 to the Consolidated Financial Statements.

Income tax expense (benefit). See Note 9 to the Consolidated Financial Statements.

See "Critical Accounting Policies and Estimates" included in this section and Note 1 to the Consolidated Financial Statements for a discussion of our accounting policies and significant assumptions related to accounting for natural gas, NGLs and oil producing activities and 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. In addition, we have commitments to pay for services and materials related to our operations, which primarily include minimum volume commitments to obtain water services and electric hydraulic fracturing services and commitments to purchase equipment, materials and sand. See Note 13 to the Consolidated Financial Statements for further discussion, including details regarding aggregate future payments for these items.

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 of the contractual commitments under our debt agreements, including the timing of principal repayments.

Unrecognized Tax Benefits. As discussed further in Note 9 to the Consolidated Financial Statements, as of December 31, 2022, we had a total reserve for unrecognized tax benefits of $105.4 million and an additional reserve of $110.7 million that was offset against deferred tax assets for general business tax credit carryforwards and net operating losses (NOLs). We settled our consolidated U.S. federal income tax liability with the IRS through 2017 in January of 2023. Other than the immaterial payment expected to be made in connection with the IRS settlement, 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 and Sales Volume. In 2023, we expect to spend approximately $1.7 to $1.9 billion in total capital expenditures, excluding amounts attributable to noncontrolling interests and acquisitions. We expect to fund planned capital expenditures with cash generated from operations and, if required, borrowings under our credit facility. 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 2023 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. In 2023, we expect our sales volume to be 1,900 to 2,000 Bcfe, excluding amounts attributable acquisitions.

Tug Hill and XcL Midstream Acquisition. On September 6, 2022, EQT Corporation and EQT Production Company (the Buyer) entered into the Tug Hill and XcL Midstream Purchase Agreement, pursuant to which we agreed to acquire THQ Appalachia I, LLC's upstream assets and THQ-XcL Holdings I, LLC's gathering and processing assets through the acquisition of all of the issued and outstanding membership interests of each of THQ Appalachia I Midco, LLC and THQ-XcL Holdings I Midco, LLC for consideration of approximately $2.6 billion in cash and 55.0 million shares of EQT Corporation common stock, as adjusted pursuant to customary closing purchase price adjustments. Upon execution of the Tug Hill and XcL Midstream Purchase Agreement, we deposited $150 million (together with any interest accrued thereon, the Escrowed Amount) into escrow, which was to be applied towards the cash consideration to be paid by the Buyer at the closing of the Tug Hill and XcL Midstream Acquisition (or, had the Tug Hill and XcL Midstream Purchase Agreement been terminated in accordance with its terms and conditions, the Escrowed Amount would have been disbursed to the Buyer or the sellers thereunder as provided in the Tug Hill and XcL Purchase Agreement). On December 23, 2022, the Tug Hill and XcL Midstream Purchase Agreement was amended to, among other things, provide that the Escrowed Amount be released to the sellers thereunder, to be used exclusively to pay down certain of the Upstream Seller's existing indebtedness, and the Upstream Seller issued to the Buyer an unsecured promissory note in an amount equal to the Escrowed Amount (the Upstream Seller Note). Upon consummation of the Tug Hill and XcL Midstream Acquisition, the loans outstanding under the Upstream Seller Note will be applied towards the cash consideration to be paid by the Buyer at the closing of the Tug Hill and XcL Midstream Acquisition and such loans will be extinguished. See Note 6 to the Consolidated Financial Statements for additional details regarding the Upstream Seller Note. On October 4, 2022, we issued $500 million aggregate principal amount of 5.678% senior notes due October 1, 2025 and $500 million aggregate principal amount of 5.700% senior notes due April 1, 2028. We intend to use the net proceeds from the sale of such notes, together with borrowings under the Term Loan Facility, cash on hand and/or borrowings under our credit facility, to fund the cash consideration for the Tug Hill and XcL Midstream Acquisition. The Tug Hill and XcL Midstream Acquisition closing is subject to regulatory approvals.

Operating Activities

Net cash provided by operating activities was $3,466 million, $1,662 million and $1,538 million for 2022, 2021 and 2020, respectively. The increase in 2022 compared to 2021 was due primarily to higher cash operating revenues, favorable changes in working capital and increased distribution of earnings from equity method investments, partly offset by higher net cash settlements paid on derivatives and higher cash operating expenses. The favorable changes in working capital also included cash received from the Cash Payment Option pursuant to the Consolidated GGA (each defined and discussed in Note 5 to the Consolidated Financial Statements). The increase in 2021 compared to 2020 was due primarily to higher cash operating revenues, partly offset by the cash settlements paid on derivatives, higher cash operating expenses and income tax refunds received in the prior year.

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 $1,422 million, $2,073 million and $1,556 million for 2022, 2021 and 2020, respectively. The decrease in 2022 compared to 2021 was due to cash paid for acquisitions in 2021 and proceeds from the sale of our remaining investment in Equitrans Midstream common stock in 2022, partly offset by increased capital expenditures and a cash deposit paid pursuant to the Tug Hill and XcL Midstream Purchase Agreement, which has since been transitioned into a loan to the Upstream Seller (see Note 6 to the Consolidated Financial Statements for additional details). The increase in 2021 compared to 2020 was due primarily to higher cash paid for acquisitions and proceeds from the sale of assets in 2020.

The following table summarizes our capital expenditures.

	Years Ended December 31,		
	2022	2021	2020
		(Millions)	
Reserve development	$ 1,131	$ 828	$ 839
Land and lease (a)	138	144	121
Capitalized overhead	51	58	51
Capitalized interest	28	18	17
Other production infrastructure	82	47	40
Other corporate items	10	9	11
Total capital expenditures	1,440	1,104	1,079
Deduct: Non-cash items (b)	(40)	(49)	(37)
Total cash capital expenditures	$ 1,400	$ 1,055	$ 1,042

(a) Capital expenditures attributable to noncontrolling interest were $12.8 million, $9.6 million and $4.9 million for the years ended December 31, 2022, 2021 and 2020, respectively.

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

Financing Activities

Net cash (used in) provided by financing activities was $(699) million, $506 million and $32 million for 2022, 2021 and 2020, respectively. For 2022, the primary uses of financing cash flows were repayment and retirement of debt, repurchase and retirement of EQT Corporation common stock and payment of dividends and the primary source of financing cash flows was net proceeds from the issuance of debt. For 2021, the primary source of financing cash flows was proceeds from the issuance of debt, and the primary uses of financing cash flows were net credit facility borrowings and repayment and retirement of debt. For 2020, the primary source of financing cash flows was proceeds from the issuance of debt and equity, and the primary use of financing cash flows was repayment and retirement of debt. See Note 10 to the Consolidated Financial Statements for further discussion of our debt.

On February 9, 2023, our Board of Directors declared a quarterly cash dividend of $0.15 per share, payable on March 1, 2023, to shareholders of record at the close of business on February 21, 2023.

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. See Note 10 to the Consolidated Financial Statements for discussion of redemptions and repurchases of debt and Note 11 to the Consolidated Financial Statements for discussion of repurchases of EQT Corporation common stock.

Security Ratings and Financing Triggers

The table below reflects the credit ratings and rating outlooks assigned to our debt instruments at February 10, 2023. 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 a description of what is deemed investment grade.

Rating agency	Senior notes	Outlook
Moody's Investors Service (Moody's)	Ba1	Positive
Standard & Poor's Ratings Service (S&P)	BBB-	Stable
Fitch Ratings Service (Fitch)	BBB-	Stable

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 our Term Loan Facility and senior notes with adjustable rates, 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 our hedging counterparties.

As of February 10, 2023, 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 10, 2023, such assurances could be up to approximately $0.6 billion, inclusive of letters of credit, OTC derivative instrument margin deposits and other collateral posted of approximately $0.2 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 and Term Loan 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 and Term Loan Facility contains financial covenants that require us to have a total debt-to-total capitalization ratio no greater than 65%. As of December 31, 2022, we were in compliance with all debt provisions and covenants under our debt agreements.

See Note 10 to the Consolidated Financial Statements for a discussion of borrowings under our credit facility. As of December 31, 2022, we had not yet borrowed, and thus, had no borrowings, under the Term Loan 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 volume and prices of our NYMEX hedge positions as of February 10, 2023. The difference between the fixed price and NYMEX price is included in average differential presented in our price reconciliation in "Average Realized Price Reconciliation." The fixed price natural gas sales agreements can be physically or financially settled.

	Q1 2023(a)	Q2 2023	Q3 2023	Q4 2023	2024
Hedged Volume (MMDth)	300	305	309	296	206
Hedged Volume (MMDth/d)	3.3	3.4	3.4	3.2	0.6
Swaps – Long					
Volume (MMDth)	45	41	42	14	—
Avg. Price ($/Dth)	$ 6.19	$ 4.77	$ 4.77	$ 4.77	$ —
Swaps – Short					
Volume (MMDth)	45	41	42	42	2
Avg. Price ($/Dth)	$ 2.97	$ 2.53	$ 2.53	$ 2.53	$ 2.67
Calls – Long					
Volume (MMDth)	46	40	40	40	51
Avg. Strike ($/Dth)	$ 3.43	$ 2.72	$ 2.72	$ 2.72	$ 3.20
Calls – Short					
Volume (MMDth)	238	300	303	197	255
Avg. Strike ($/Dth)	$ 9.42	$ 4.85	$ 4.85	$ 4.69	$ 5.07
Puts – Long					
Volume (MMDth)	299	304	308	268	204
Avg. Strike ($/Dth)	$ 4.50	$ 3.39	$ 3.39	$ 3.51	$ 4.21
Fixed Price Sales					
Volume (MMDth)	1	1	1	—	—
Avg. Price ($/Dth)	$ 2.43	$ 2.38	$ 2.38	$ —	$ —
Option Premiums					
Cash Settlement of Deferred Premiums (millions)	$ (98)	$ (70)	$ (71)	$ (92)	$ (10)

(a) January 1 through March 31.

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.

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

As of December 31, 2022, we did not have any material off-balance sheet arrangements other than the commitments described in Note 13 to the Consolidated Financial Statements.

Commitments and Contingencies

See Note 13 to the Consolidated Financial Statements for a discussion of our commitments and contingencies.

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, NGLs and Oil Producing Activities. We use the successful efforts method of accounting for our oil and gas producing activities. See Note 1 to the Consolidated Financial Statements for a discussion of the fair value measurement and any subsequent impairments of our proved and unproved oil and gas properties and other long-lived assets as well as evaluation of the recoverability of capitalized costs of unproved oil and gas properties.

We believe accounting for natural gas, NGLs 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. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

See Note 1 to the Consolidated Financial Statements for additional information on impairments of our proved and unproved 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."

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 volume 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 currently enacted 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. Based on proved reserves at December 31, 2022, we estimate that a 1% change in proved reserves would decrease or increase 2023 depletion expense by approximately $16 million and $20 million, respectively, based on current production estimates for 2023.

See also 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."

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. See Note 1 to the Consolidated Financial Statements for a discussion of accounting policies related to income taxes and Note 9 to the Consolidated Financial Statements for a discussion of deferred tax assets, valuation allowances and the amount of financial statement benefit recorded for uncertain tax positions.

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. 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. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

Derivative Instruments. We enter into derivative commodity instrument contracts primarily to reduce exposure to commodity price risk associated with future sales of our natural gas production. See Note 4 to the Consolidated Financial Statements for a description of the fair value hierarchy. 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.

Business Combinations. Accounting for a business combination requires a company to record the identifiable assets and liabilities acquired at fair value. In the third quarter of 2021, we completed the Alta Acquisition, and in the fourth quarter of 2020, we completed the Chevron Acquisition. See Note 6 to the Consolidated Financial Statements for a discussion of the most significant assumptions used to estimate the fair value of the assets and liabilities acquired.

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. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

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. See Note 13 to the Consolidated Financial Statements.

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. See Note 1 to the Consolidated Financial Statements.

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. An estimate of the sensitivity to changes in our assumptions is not practicable given the numerous assumptions that can materially affect our estimates.

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 LOE, 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, and, depending on our then-current credit ratings and the terms of our hedging contracts, we may be required to post additional margin with our hedging counterparties.

The overall objective of our hedging program is to protect our 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. Our use of derivative instruments is implemented under a set of policies approved by our management-level Hedge and Financial Risk Committee and is 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 NYMEX natural gas price on December 31, 2022 and 2021 would increase the fair value of our natural gas derivative commodity instruments by approximately $727 million and $577 million, respectively. A hypothetical increase of 10% in the NYMEX natural gas price on December 31, 2022 and 2021 would decrease the fair value of our natural gas derivative commodity instruments by approximately $333 million and $581 million, respectively. For purposes of this analysis, we applied the 10% change in the NYMEX natural gas price on December 31, 2022 and 2021 to our natural gas derivative commodity instruments as of December 31, 2022 and 2021 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 natural 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 rate we pay on borrowings under our credit facility and 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 the borrowings under our credit facility during the year ended December 31, 2022 would have increased interest expense by approximately $5 million. We had no borrowings under our Term Loan Facility as of December 31, 2022.

Interest rates on our 6.125% senior notes due 2025 and 7.00% senior notes due 2030 fluctuate based on changes to the credit ratings assigned to our senior notes by Moody's, S&P and Fitch. Interest rates on our other outstanding senior notes do not 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 measurement 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 36%, or $710 million, of our OTC derivative contracts outstanding at December 31, 2022 had a positive fair value. Approximately 17%, or $477 million, of our OTC derivative contracts outstanding at December 31, 2021 had a positive fair value.

As of December 31, 2022, 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, 2022, 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 our 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 our 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

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, 2022 and 2021, the related consolidated statements of operations, comprehensive loss, cash flows and equity for each of the three years in the period ended December 31, 2022, 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 financial position of the Company at December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, 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, 2022, 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 16, 2023 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 Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

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

Description of the Matter	At December 31, 2022, the net book value of the Company's proved oil and natural gas properties was $16,023 million, and depreciation, depletion and amortization (DD&A) expense was $1,666 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 prepared using standard geological and engineering methods generally recognized in the petroleum industry based on evaluations of estimated in-place hydrocarbon volumes using financial and non-financial inputs. Significant judgment is required by the Company's engineers in interpreting the 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, and future operating and capital costs assumptions, 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, 2022. 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.
How We Addressed the Matter in Our Audit	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. 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. Finally, we tested that the DD&A expense calculations are based on the appropriate proved natural gas, NGLs, and oil reserve balances from the Company's reserve report.

/s/ Ernst & Young LLP
We have served as the Company's auditor since 1950.
Pittsburgh, Pennsylvania
February 16, 2023

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, 2022, 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, 2022, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2022 and 2021, the related consolidated statements of operations, comprehensive loss, cash flows and equity for each of the three years in the period ended December 31, 2022 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 16, 2023 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 16, 2023

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

	2022	2021	2020
	(Thousands, except per share amounts)		
Operating revenues:			
Sales of natural gas, natural gas liquids and oil	$ 12,114,168	$ 6,804,020	$ 2,650,299
(Loss) gain on derivatives	(4,642,932)	(3,775,042)	400,214
Net marketing services and other	26,453	35,685	8,330
Total operating revenues	7,497,689	3,064,663	3,058,843
Operating expenses:			
Transportation and processing	2,116,976	1,942,165	1,710,734
Production	300,985	225,279	155,403
Exploration	3,438	24,403	5,484
Selling, general and administrative	252,645	196,315	174,769
Depreciation and depletion	1,665,962	1,676,702	1,393,465
Amortization of intangible assets	—	—	26,006
(Gain) loss/impairment on sale/exchange of long-lived assets	(8,446)	(21,124)	100,729
Impairment of contract and other assets	214,195	—	34,694
Impairment and expiration of leases	176,606	311,835	306,688
Other operating expenses	57,331	70,063	28,537
Total operating expenses	4,779,692	4,425,638	3,936,509
Operating income (loss)	2,717,997	(1,360,975)	(877,666)
Gain on Equitrans Share Exchange (Note 5)	—	—	(187,223)
Loss (income) from investments	4,931	(71,841)	314,468
Dividend and other income	(11,280)	(19,105)	(35,512)
Loss on debt extinguishment	140,029	9,756	25,435
Interest expense	249,655	289,753	259,268
Income (loss) before income taxes	2,334,662	(1,569,538)	(1,254,102)
Income tax expense (benefit)	553,720	(428,037)	(295,293)
Net income (loss)	1,780,942	(1,141,501)	(958,809)
Less: Net income (loss) attributable to noncontrolling interests	9,977	1,246	(10)
Net income (loss) attributable to EQT Corporation	$ 1,770,965	$ (1,142,747)	$ (958,799)
Income (loss) per share of common stock attributable to EQT Corporation:			
Basic:			
Weighted average common stock outstanding	370,048	323,196	260,613
Net income (loss) attributable to EQT Corporation	$ 4.79	$ (3.54)	$ (3.68)
Diluted (Note 1):			
Weighted average common stock outstanding	406,495	323,196	260,613
Net income (loss) attributable to EQT Corporation	$ 4.38	$ (3.54)	$ (3.68)

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

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

	2022	2021	2020
		(Thousands)	
Net income (loss)	$ 1,780,942	$ (1,141,501)	$ (958,809)
Other comprehensive income (loss), net of tax:			
Other postretirement benefits liability adjustment, net of tax: $488, $254 and $(36)	1,617	744	(156)
Comprehensive income (loss)	1,782,559	(1,140,757)	(958,965)
Less: Comprehensive income (loss) attributable to noncontrolling interest	9,977	1,246	(10)
Comprehensive income (loss) attributable to EQT Corporation	$ 1,772,582	$ (1,142,003)	$ (958,955)

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

EQT CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

	2022	2021
	(Thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,458,644	$ 113,963
Accounts receivable (less provision for doubtful accounts: $605 and $321)	1,608,089	1,438,031
Derivative instruments, at fair value	812,371	543,337
Prepaid expenses and other	135,337	191,435
Total current assets	4,014,441	2,286,766
Property, plant and equipment	27,393,919	26,016,092
Less: Accumulated depreciation and depletion	9,226,586	7,597,172
Net property, plant and equipment	18,167,333	18,418,920
Contract asset	—	410,000
Other assets	488,152	491,702
Total assets	$ 22,669,926	$ 21,607,388
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of debt	$ 422,632	$ 1,060,970
Accounts payable	1,574,610	1,339,251
Derivative instruments, at fair value	1,393,487	2,413,608
Other current liabilities	341,491	372,412
Total current liabilities	3,732,220	5,186,241
Senior notes	5,167,849	4,435,782
Note payable to EQM Midstream Partners, LP	88,484	94,320
Deferred income taxes	1,442,406	907,306
Other liabilities and credits	1,025,639	1,012,740
Total liabilities	11,456,598	11,636,389
Equity:		
Common stock, no par value, shares authorized: 640,000, shares issued: 365,363 and 377,432	9,891,890	10,071,820
Treasury stock, shares at cost: zero and 1,033	—	(18,046)
Retained earnings (accumulated deficit)	1,283,578	(94,400)
Accumulated other comprehensive loss	(2,994)	(4,611)
Total common shareholders' equity	11,172,474	9,954,763
Noncontrolling interest in consolidated subsidiaries	40,854	16,236
Total equity	11,213,328	9,970,999
Total liabilities and equity	$ 22,669,926	$ 21,607,388

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,

	2022	2021	2020
		(Thousands)	
Cash flows from operating activities:			
Net income (loss)	$ 1,780,942	$ (1,141,501)	$ (958,809)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Deferred income tax expense (benefit)	534,612	(427,470)	(152,275)
Depreciation and depletion	1,665,962	1,676,702	1,393,465
Amortization of intangible assets	—	—	26,006
Impairments and (gain) loss on sale/exchange of long-lived assets	382,355	290,711	442,111
Gain on Equitrans Share Exchange	—	—	(187,223)
Loss (income) from investments	4,931	(71,841)	314,468
Loss on debt extinguishment	140,029	9,756	25,435
Share-based compensation expense	45,201	28,169	19,552
Distribution of earnings from equity method investment	50,220	14,911	—
Amortization, accretion and other	32,645	32,175	25,482
Loss (gain) on derivatives	4,642,932	3,775,042	(400,214)
Cash settlements (paid) received paid on derivatives	(5,927,698)	(2,091,003)	897,190
Net premiums received (paid) on derivative instruments	14,200	(66,495)	(46,665)
Changes in other assets and liabilities:			
Accounts receivable	(168,978)	(699,992)	(36,296)
Accounts payable	181,459	456,988	(29,193)
Income tax receivable and payable	—	(23,909)	322,763
Other current assets	48,576	(75,100)	(68,628)
Other items, net	38,172	(24,695)	(49,468)
Net cash provided by operating activities	3,465,560	1,662,448	1,537,701
Cash flows from investing activities:			
Capital expenditures	(1,400,443)	(1,055,128)	(1,042,231)
Cash paid for acquisitions, net of cash acquired (Note 6)	(55,347)	(1,030,239)	(691,942)
Deposit on acquisition (Note 6)	(150,000)	—	—
Proceeds from sale/exchange of assets	8,572	2,452	126,080
Proceeds from sale/exchange of investment shares	189,249	24,369	52,323
Other investing activities	(13,784)	(14,196)	(30)
Net cash used in investing activities	(1,421,753)	(2,072,742)	(1,555,800)
Cash flows from financing activities:			
Net proceeds from issuance of common stock	—	—	340,923
Proceeds from credit facility borrowings	10,242,000	8,086,000	3,118,250
Repayment of credit facility borrowings	(10,242,000)	(8,386,000)	(3,112,250)
Proceeds from issuance of debt	1,000,000	1,000,000	2,600,000
Debt issuance costs and Capped Call Transactions (Note 10)	(26,506)	(19,713)	(71,056)
Repayment and retirement of debt	(917,039)	(154,336)	(2,822,262)
Premiums paid on debt extinguishment	(135,308)	(9,599)	(21,132)
Repurchase and retirement of common stock	(409,485)	(12,922)	—
Dividends paid	(203,629)	—	(7,664)
Contribution from noncontrolling interest	15,000	7,500	7,500
Distribution to noncontrolling interest	(11,592)	—	—
Other financing activities	(10,567)	(4,883)	(596)
Net cash (used in) provided by financing activities	(699,126)	506,047	31,713
Net change in cash and cash equivalents	1,344,681	95,753	13,614
Cash and cash equivalents at beginning of year	113,963	18,210	4,596
Cash and cash equivalents at end of year	$ 1,458,644	$ 113,963	$ 18,210

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

EQT CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED EQUITY
YEARS ENDED DECEMBER 31, 2022, 2021 and 2020

	Common Stock						
	Shares	**No Par Value**	**Treasury Stock**	**Retained Earnings (Accumulated Deficit)**	**Accumulated Other Comprehensive Loss (a)**	**Noncontrolling Interest in Consolidated Subsidiaries**	**Total Equity**
	(Thousands, except per share amounts)						
Balance at December 31, 2019	255,171	$ 7,818,205	$ (32,507)	$ 2,023,089	$ (5,199)	$ —	$ 9,803,588
Comprehensive loss, net of tax:							
Net loss				(958,799)		(10)	(958,809)
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
Capped Call Transactions (Note 10)		(32,500)					(32,500)
Issuance of common stock	23,000	340,923					340,923
Contribution from noncontrolling interest						7,500	7,500
Balance at December 31, 2020	278,345	8,145,539	(29,348)	1,056,626	(5,355)	7,490	9,174,952
Comprehensive (loss) income, net of tax:							
Net (loss) income				(1,142,747)		1,246	(1,141,501)
Other postretirement benefits liability adjustment, net of tax: $254					744		744
Share-based compensation plans	627	21,982	11,302				33,284
Repurchase and retirement of common stock	(1,362)	(21,106)		(8,279)			(29,385)
Alta Acquisition (Note 6)	98,789	1,925,405					1,925,405
Contribution from noncontrolling interest						7,500	7,500
Balance at December 31, 2021	376,399	10,071,820	(18,046)	(94,400)	(4,611)	16,236	9,970,999
Comprehensive income, net of tax:							
Net income				1,770,965		9,977	1,780,942
Other postretirement benefits liability adjustment, net of tax: $488					1,617		1,617
Dividends ($0.55 per share)				(203,629)			(203,629)
Share-based compensation plans	2,100	23,671	18,046				41,717
Convertible Notes settlements (Note 10)	4	63					63
Repurchase and retirement of common stock	(13,140)	(203,664)		(189,358)			(393,022)
Distribution to noncontrolling interest						(11,592)	(11,592)
Contribution from noncontrolling interest						15,000	15,000
Other						11,233	11,233
Balance at December 31, 2022	365,363	$ 9,891,890	$ —	$ 1,283,578	$ (2,994)	$ 40,854	$ 11,213,328

Common shares authorized: 640,000. Preferred shares authorized: 3,000. There were no preferred shares issued or outstanding.

(a) Amounts included in accumulated other comprehensive loss are related to other postretirement benefits liability adjustments, net of tax, which are attributable to net actuarial losses and net prior service costs.

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

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 Corporation directly or indirectly holds a controlling interest (collectively, the Company). Intercompany accounts and transactions have been eliminated in consolidation. Management evaluates whether an entity or interest is a variable interest entity and whether the Company is the primary beneficiary; consolidation is required if both criteria are met. The Company records noncontrolling interest in its Consolidated Financial Statements for any non-wholly-owned consolidated subsidiary.

Certain of the Company's midstream gathering systems are not wholly-owned but are operated by the Company pursuant to a construction, ownership and operation agreement. The Company records the pro rata share of revenues, expenses, assets and liabilities that it is entitled under the agreement in the Company's financial statements.

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.

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 herein. 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 description of the fair value hierarchy and a discussion of the Company's fair value measurements.

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

	December 31,	
	2022	2021
	(Thousands)	
Margin requirements with counterparties (see Note 3)	$ 100,623	$ 147,773
Prepaid expenses and other current assets	34,714	43,662
Total prepaid expenses and other	$ 135,337	$ 191,435

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

	December 31, 2022	December 31, 2021
	(Thousands)	
Oil and gas producing properties	$ 26,890,562	$ 25,523,854
Less: Accumulated depreciation and depletion	9,119,553	7,508,178
Net oil and gas producing properties	17,771,009	18,015,676
Other properties, at cost less accumulated depreciation	396,324	403,244
Net property, plant and equipment	$ 18,167,333	$ 18,418,920

The Company uses the successful efforts method of accounting for gas, NGLs 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, $58 million and $51 million in 2022, 2021 and 2020, respectively. The Company also capitalized interest expense related to well development of approximately $28 million, $18 million and $17 million in 2022, 2021 and 2020, respectively. Depletion expense is calculated based on actual produced sales volume 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 $0.85, $0.89 and $0.92 per Mcfe for the years ended December 31, 2022, 2021 and 2020, respectively.

There were no exploratory wells drilled during 2022, 2021 and 2020, and there were no capitalized exploratory well costs for the years ended December 31, 2022, 2021 and 2020.

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 during 2022, 2021 and 2020.

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. The Company recognizes impairment if the Company does not have the intent to drill on the leased 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. The Company recognizes expense for lease expirations as the lease expires if the lease was not previously impaired. For the years ended December 31, 2022, 2021 and 2020, the Company recorded $176.6 million, $311.8 million and $306.7 million, respectively, for impairment and expiration of leases. The Company's unproved properties had a net book value of approximately $1,748 million and $2,406 million at December 31, 2022 and 2021, respectively.

Equity Method Investments. The Company applies the equity method of accounting to its investments in entities that the Company does not have the power to direct the activities that most significantly affect those entities' economic performance. The carrying value of the Company's equity method investments is recorded in other assets in the Consolidated Balance Sheets. The Company's pro-rata share of income/loss from the Company's equity method investments is recorded in loss (income) from investments in the Statements of Consolidated Operations.

The Company evaluates its equity method investments for impairment when events or changes in circumstances indicate that the investment's fair value is less than its carrying value. The recognition of an impairment loss is required if the impairment is considered other than temporary.

Investments in Equity Securities. The Company has an investment in a fund (the Investment Fund) that invests in companies that develop technology and operating solutions for exploration and production companies. The Company does not have the ability to exercise significant influence over the Investment Fund and, as such, accounts for its investment in the Investment Fund as an investment in equity securities that is recorded at fair value in other assets in the Consolidated Balance Sheets. The Company values its investment using, as a practical expedient, the net asset value provided in the financial statements received from fund managers. Changes in the fair value of the Company's investment in the Investment Fund are recorded in loss (income) from investments in the Statements of Consolidated Operations. Dividends received on the Company's investment in the Investment Fund are recorded in dividend and other income in the Statements of Consolidated Operations.

The Company previously owned shares of common stock of Equitrans Midstream Corporation (Equitrans Midstream). During 2022, the Company sold the remaining balance of its shares of Equitrans Midstream's common stock. The Company did not have the ability to exercise significant influence over Equitrans Midstream or any of its subsidiaries and, as such, accounted for its investment in Equitrans Midstream as an investment in equity securities that, as of December 31, 2021, was recorded at fair value in other assets in the Consolidated Balance Sheet. The Company valued its investment 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 the fair value of the Company's investment in Equitrans Midstream were recorded in loss (income) from investments in the Statements of Consolidated Operations. Dividends received on the Company's investment in Equitrans Midstream were recorded in dividend and other income in the Statements of Consolidated Operations.

Contract Asset. See Note 5 for discussion of the Company's contract asset and impairment thereof.

Intangible Assets. The Company's intangible assets, composed of non-compete agreements with former Rice Energy Inc. executives, were fully amortized as of December 31, 2020.

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

	December 31,	
	2022	**2021**
	(Thousands)	
Accrued interest payable	$ 88,484	$ 88,614
Accrued taxes other than income	84,755	86,755
Accrued incentive compensation	50,894	51,224
Current portion of long-term capacity contracts	39,589	57,440
Current portion of lease liabilities	35,449	27,972
Other accrued liabilities	42,320	60,407
Total other current liabilities	$ 341,491	$ 372,412

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 loss. 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 items charged or credited directly to shareholders' equity.

Deferred 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. When evaluating whether or not a valuation allowance should be established, the Company exercises 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, the Company considers all available evidence, both positive and negative, including carrybacks, tax planning strategies, reversals of deferred tax assets and liabilities and forecasted future taxable income.

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. To determine the amount of financial statement benefit recorded for uncertain tax positions, the Company considers 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. 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, fiduciary liability, director and officers' liability 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, workers compensation and environmental liability; however, the Company now maintains insurance for such losses arising on or after November 12, 2020. Reserves are estimated based on analyses of historical data and actuarial estimates, where applicable, and are not discounted. The recorded reserves represent estimates of the ultimate cost of claims incurred as of the balance sheet date. The liabilities are reviewed by the Company quarterly and by independent actuaries, where applicable, annually to ensure appropriateness.

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 well pads, reclaiming water impoundments, 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,	
	2022	2021
	(Thousands)	
Balance at January 1	$ 661,334	$ 523,557
Accretion expense	36,613	30,690
Liabilities incurred	34,363	10,738
Liabilities settled	(19,055)	(19,149)
Liabilities assumed in acquisitions	—	113,590
Liabilities removed in divestitures	(697)	(3,315)
Change in estimates	20,245	5,223
Balance at December 31	$ 732,803	$ 661,334

The Company does not have any assets that are legally restricted for purposes of settling these obligations. The Company operates in several states that have implemented expanded requirements resulting 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 12 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,		
	2022	**2021**	**2020**
		(Thousands)	
Changes in legal and environmental reserves, including settlements	$ 30,394	$ 5,175	$ 11,350
Transactions	14,185	57,430	11,739
Energy transition initiatives	11,985	—	—
Reorganization, including severance and contract terminations	767	7,458	5,448
Total other operating expenses	$ 57,331	$ 70,063	$ 28,537

Defined Contribution Plan and Other Postretirement Benefits Plan. The Company recognized expense related to its defined contribution plan of $7.8 million, $7.0 million and $6.5 million for the years ended December 31, 2022, 2021 and 2020, respectively. In addition, the Company sponsors an other postretirement benefits plan.

Earnings Per Share (EPS). Basic EPS is computed by dividing net income (loss) attributable to EQT Corporation by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income (loss) attributable to EQT Corporation plus the applicable numerator adjustments 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 Convertible Notes (defined in Note 10). Purchases of treasury shares are calculated using the average share price of EQT Corporation common stock during the period. The Company uses the if-converted method to calculate the impact of the Convertible Notes on diluted earnings (loss) per share.

The following table shows the computation for basic and diluted EPS.

	Year Ended December 31, 2022
	(Thousands, except per share amounts)
Net income attributable to EQT Corporation – basic earnings available to shareholders	$ 1,770,965
Add back: Interest expense on Convertible Notes, net of tax	8,019
Diluted earnings available to shareholders	$ 1,778,984
Weighted average common stock outstanding – basic	370,048
Options, restricted stock, performance awards and stock appreciation rights	5,731
Convertible debt	30,716
Weighted average common stock outstanding – diluted	406,495
Income per share of common stock attributable to EQT Corporation:	
Basic	$ 4.79
Diluted	$ 4.38

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, 2021 and 2020, all such securities of 8.2 million and 6.8 million, respectively, were excluded from potentially dilutive securities because of their anti-dilutive effect on loss per share. In addition, for the years ended December 31, 2021 and 2020, if-converted securities of approximately 33.3 million shares were excluded from potentially dilutive securities because of their 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 Statements of Consolidated Cash Flows.

	Years Ended December 31,		
	2022	2021	2020
		(Thousands)	
Cash paid (received) during the year for:			
Interest, net of amount capitalized	$ 236,797	$ 280,511	$ 195,681
Income taxes, net	20,773	19,155	(448,906)
Non-cash activity during the period for:			
Increase in asset retirement costs and obligations	$ 54,608	$ 15,961	$ 52,271
Increase in right-of-use assets and lease liabilities, net	23,356	20,834	18,877
Capitalization of non-cash equity share-based compensation	5,406	4,994	3,142
Issuance of common stock for Convertible Notes settlements (Note 10)	63	—	—
Equity issued as consideration for the Alta Acquisition (Note 6)	—	1,925,405	—

Recently Issued Accounting Standards

In August 2020, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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 Accounting Standards Codification 815 or that 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. Under ASU 2020-06, entities are required to use the if-converted method to calculate the impact of convertible instruments on diluted EPS. The if-converted method assumes share settlement of the instrument, which increases the number of potentially dilutive securities used to calculate diluted EPS. This ASU also adds several new disclosure requirements.

The Company adopted ASU 2020-06 effective as of January 1, 2022 using the full retrospective method of adoption. Accordingly, the consolidated financial statements have been recast. The following tables present the impact of the adoption of ASU 2020-06 on the Company's previously reported historical results. See Note 10 for discussion of the Convertible Notes.

	Year Ended December 31, 2021		
	As Reported	ASU 2020-06 Adoption Adjustment	As Adjusted
	(Thousands, except per share amounts)		
Interest expense	$ 308,903	$ (19,150)	$ 289,753
Income tax benefit	(434,175)	6,138	(428,037)
Net loss	(1,154,513)	13,012	(1,141,501)
Less: Net income attributable to noncontrolling interests	1,246	—	1,246
Net loss attributable to EQT Corporation	$ (1,155,759)	$ 13,012	$ (1,142,747)
Basic and diluted:			
Weighted average common stock outstanding (a)	323,196	—	323,196
Net loss per share of common stock attributable to EQT Corporation	$ (3.58)	$ 0.04	$ (3.54)

(a) For the year ended December 31, 2021, diluted weighted average common stock outstanding did not change because the potentially dilutive securities had an anti-dilutive effect on loss per share.

	Year Ended December 31, 2020		
	As Reported	ASU 2020-06 Adoption Adjustment	As Adjusted
	(Thousands, except per share amounts)		
Interest expense	$ 271,200	$ (11,932)	$ 259,268
Income tax benefit	(298,858)	3,565	(295,293)
Net loss	(967,176)	8,367	(958,809)
Less: Net loss attributable to noncontrolling interest	(10)	—	(10)
Net loss attributable to EQT Corporation	$ (967,166)	$ 8,367	$ (958,799)
Basic and diluted:			
Weighted average common stock outstanding (a)	260,613	—	260,613
Net loss per share of common stock attributable to EQT Corporation	$ (3.71)	$ 0.03	$ (3.68)

(a) For the year ended December 31, 2020, diluted weighted average common stock outstanding did not change because the potentially dilutive securities had an anti-dilutive effect on loss per share.

	December 31, 2021		
	As Reported	ASU 2020-06 Adoption Adjustment	As Adjusted
	(Thousands)		
Current portion of debt (a)	$ 954,900	$ 106,070	$ 1,060,970
Deferred income taxes	938,612	(31,306)	907,306
Common stock, no par value	10,167,963	(96,143)	10,071,820
Accumulated deficit	(115,779)	21,379	(94,400)

(a) Pursuant to the terms of the Convertible Notes indenture, a sale price condition for conversion of the Convertible Notes was satisfied as of December 31, 2021, and, accordingly, holders of the Convertible Notes were permitted to convert any of their

Convertible Notes at their option at any time during the three months ended March 31, 2022, subject to all terms and conditions set forth in the Convertible Notes indenture. Therefore, as of December 31, 2021, the net carrying value of the Convertible Notes was included in current portion of debt in the Consolidated Balance Sheet.

Certain line items in the Statements of Consolidated Cash Flows were adjusted to reflect the impact of the adoption of ASU 2020-06; however, the adoption did not impact cash and did not change net cash provided by operating, investing or financing activities.

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, 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 acts 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 $1,171.9 million and $1,093.9 million in accounts receivable in the Consolidated Balance Sheets as of December 31, 2022 and 2021, respectively.

The table below provides disaggregated information on the Company's revenues. Derivative contracts and certain other revenue contracts are outside the scope of ASU 2014-09, *Revenue from Contracts with Customers.*

	Years Ended December 31,		
	2022	**2021**	**2020**
		(Thousands)	
Revenues from contracts with customers:			
Natural gas sales	$ 11,448,293	$ 6,180,176	$ 2,459,854
NGLs sales	586,715	531,510	169,871
Oil sales	79,160	92,334	20,574
Total revenues from contracts with customers	$ 12,114,168	$ 6,804,020	$ 2,650,299
Other sources of revenue:			
(Loss) gain on derivatives	(4,642,932)	(3,775,042)	400,214
Net marketing services and other	26,453	35,685	8,330
Total operating revenues	$ 7,497,689	$ 3,064,663	$ 3,058,843

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, 2022. Amounts shown exclude contracts that qualified for the exception to the relative standalone selling price method as of December 31, 2022.

	2023	2024	Total
		(Thousands)	
Natural gas sales	$ 14,107	$ 469	$ 14,576

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 (loss) gain on derivatives 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 its expected sales of production and portions of its basis exposure covering approximately 1,424 billion cubic feet (Bcf) of natural gas and 1,483 thousand barrels (Mbbl) of NGLs as of December 31, 2022 and 2,184 Bcf of natural gas and 3,055 Mbbl of NGLs as of December 31, 2021. The open positions at both December 31, 2022 and 2021 had maturities extending through December 2027.

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), S&P Global Ratings (S&P) or Fitch Ratings Service (Fitch) 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, S&P or Fitch 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. Anything below these ratings is considered non-investment grade. As of December 31, 2022, the Company's senior notes were rated "Ba1" by Moody's, "BBB–" by S&P and "BBB–" by Fitch.

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, 2022 and 2021, the aggregate fair value of all OTC derivative instruments with credit rating risk-related contingent features that were in a net liability position was $347.6 million and $594.9 million, respectively, for which, the Company deposited and recorded current assets of zero and $0.1 million, respectively.

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 both December 31, 2022 and 2021, 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, 2022 and 2021, the Company recorded $100.6 million and $147.7 million, respectively, of such deposits as current assets in the Consolidated Balance Sheets.

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, 2022		(Thousands)		
Asset derivative instruments at fair value	$ 812,371	$ (756,495)	$ —	$ 55,876
Liability derivative instruments at fair value	1,393,487	(756,495)	(100,623)	536,369
December 31, 2021				
Asset derivative instruments at fair value	$ 543,337	$ (468,266)	$ —	$ 75,071
Liability derivative instruments at fair value	2,413,608	(468,266)	(147,773)	1,797,569

Refer to Note 5 for a discussion of the derivative liability recorded in connection with the Equitrans Share Exchange (defined therein). Refer to Note 8 for a discussion of the derivative liability recorded in connection with the 2020 Divestiture (defined therein).

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 NGLs 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.

		Fair value measurements at reporting date using:		
	Gross derivative instruments recorded in the Consolidated Balance Sheets	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
December 31, 2022		**(Thousands)**		
Asset derivative instruments at fair value	$ 812,371	$ 103,028	$ 709,343	$ —
Liability derivative instruments at fair value	1,393,487	154,601	1,238,886	—
December 31, 2021				
Asset derivative instruments at fair value	$ 543,337	$ 66,833	$ 476,504	$ —
Liability derivative instruments at fair value	2,413,608	126,053	2,287,555	—

The carrying values of cash equivalents, accounts receivable and accounts payable approximate fair value due to their short-term maturities. The carrying value of borrowings under the Company's credit facility approximates fair value as the interest rate is based on prevailing market rates. The Company considered all of these fair values to be Level 1 fair value measurements.

The Investment Fund is valued using, as a practical expedient, the net asset value provided in the financial statements received from fund managers.

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, 2022 and 2021, the Company's senior notes had a fair value of approximately $6.1 billion and $6.5 billion, respectively, and a carrying value of approximately $5.6 billion and $5.5 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, 2022 and 2021, the Company's note payable to EQM had a fair value of approximately $96 million and $118 million, respectively, and a carrying value of approximately $94 million and $100 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.

See Note 5 for a discussion of the fair value measurement of the Equitrans Share Exchange. See Notes 6, 7 and 8 for a discussion of the fair value measurement of the Company's acquisitions, asset exchange transactions and divestiture, respectively. See Note 1 for a discussion of the fair value measurement and any subsequent impairments of the Company's proved and unproved oil and gas properties and other long-lived assets.

5. Contract Asset

During the first quarter of 2020, the Company sold to Equitrans Midstream a total of 25,299,752 shares 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 rate relief was effected through the execution of a consolidated gas gathering and compression agreement entered into between the Company and an affiliate of EQM (the Consolidated GGA).

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, because the Mountain Valley Pipeline was not in service by January 1, 2022, the Consolidated GGA provided the Company the option to forgo a portion of the gathering fee relief that would otherwise be applicable following the Mountain Valley Pipeline in-service date in exchange for a cash payment of approximately $196 million (the Cash Payment Option).

On the closing date of the Equitrans Share Exchange, the Company recorded in the Consolidated Balance Sheet a contract asset of $410 million representing the estimated fair value of the rate relief inclusive of the Cash Payment Option. The Company also recorded 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.

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. 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.

The fair value of the contract asset at inception and the estimated future cash flows were based on significant inputs that are not observable in the market and, as such, are a Level 3 fair value measurement. The fair value of the derivative liability related to the Henry Hub Cash Bonus 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. Key assumptions used in the fair value calculation of the contract asset included the following: (i) a probability-weighted estimate of the in-service date of the Mountain Valley Pipeline, (ii) an estimate of the potential exercise and timing of the Cash Payment Option; (iii) an estimated production volume forecast and (iv) a market-based weighted average cost of capital.

During 2022, the Company identified indicators that the carrying value of the contract asset may not be fully recoverable, including increased uncertainty of the estimated timing of completion of the Mountain Valley Pipeline due to court rulings and public statements from Equitrans Midstream with respect to its completion. As a result of the Company's impairment evaluation, the Company recognized impairment of $214 million in the Statement of Consolidated Operations. During 2022, the Company elected to exercise the Cash Payment Option provided by the Consolidated GGA and received cash proceeds of $196 million as a result of making such election. As of December 31, 2022, the impairment and election of the Cash Payment Option reduced the carrying value of the contract asset to zero. As of December 31, 2022, the Company also reduced the derivative liability related to the Henry Hub Cash Bonus to zero given the uncertainties surrounding the in-service date of the Mountain Valley Pipeline and the Company's belief that achieving an in-service date of the Mountain Valley Pipeline prior to December 31, 2024 is not probable. Future changes in the uncertainties surrounding the in-service date of the Mountain Valley Pipeline could result in future changes to the accounting treatment of the Henry Hub Cash Bonus.

There was no impairment of the contract asset in 2021 or 2020.

6. Acquisitions

Tug Hill and XcL Midstream Acquisition

On September 6, 2022 (the Original Execution Date), EQT Corporation entered into a purchase agreement (the Original Purchase Agreement) with its wholly-owned indirect subsidiary EQT Production Company (the Buyer, and together with EQT Corporation, the EQT Parties), THQ Appalachia I, LLC (the Upstream Seller) and THQ-XcL Holdings I, LLC (the Midstream Seller, and together with the Upstream Seller, the Sellers), pursuant to which the EQT Parties agreed to acquire the Upstream Seller’s upstream assets and the Midstream Seller’s gathering and processing assets through the acquisition of all of the issued and outstanding membership interests of each of THQ Appalachia I Midco, LLC and THQ-XcL Holdings I Midco, LLC (the Tug Hill and XcL Midstream Acquisition) for consideration of approximately $2.6 billion in cash and 55.0 million shares of EQT Corporation common stock, as adjusted pursuant to customary closing purchase price adjustments.

Following execution of the Original Purchase Agreement, the EQT Parties and the ultimate parent entities of the to-be-acquired interests and assets thereunder each received a request for additional information and documentary materials (the Second

Request) from the U.S. Federal Trade Commission (the FTC) in connection with the FTC's review of the Tug Hill and XcL Midstream Acquisition. The Second Request extends the waiting period imposed by the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the HSR Act), until 30 days after the parties have substantially complied with the Second Request, unless that period is terminated sooner by the FTC. As a result, subject to certain exceptions provided in the Original Purchase Agreement, either the Buyer or the Sellers had the right to terminate the Original Purchase Agreement if the Tug Hill and XcL Midstream Acquisition did not close by December 30, 2022 (the Original Outside Date).

On December 23, 2022 (the A&R Execution Date), the EQT Parties and the Sellers entered into an Amended and Restated Purchase Agreement (the A&R Purchase Agreement, and the Original Purchase Agreement, as amended by the A&R Purchase Agreement, is referred to herein as the Tug Hill and Xcl Midstream Purchase Agreement), which amends and restates the Original Purchase Agreement in its entirety and, among other things, extends the Original Outside Date to December 29, 2023. The A&R Purchase Agreement also contains other amendments to the Original Purchase Agreement that are related to such extension, including modifications to certain purchase price adjustments and interim period operating covenants for the period beginning after the A&R Execution Date.

Pursuant to the Original Purchase Agreement, within two business days after the Original Execution Date, the Company deposited $150 million (together with any interest accrued thereon, the Escrowed Amount) into escrow, which was to be applied towards the cash consideration to be paid by the Buyer at the closing of the Tug Hill and XcL Midstream Acquisition (or, had the Original Purchase Agreement been terminated in accordance with its terms and conditions, the Escrowed Amount would have been disbursed to the Company or the Sellers as provided in the Original Purchase Agreement). Pursuant to the A&R Purchase Agreement, on the A&R Execution Date, the Company and the Sellers instructed the escrow agent to release the Escrowed Amount to the Sellers, to be used exclusively to pay down certain of the Upstream Seller's existing indebtedness, and the Upstream Seller issued to the Company an unsecured promissory note in an amount equal to the Escrowed Amount (the Upstream Seller Note). The maturity date of the Upstream Seller Note is one year after the Termination Date (as defined in the A&R Purchase Agreement). Prior to the Termination Date, interest on the Upstream Seller Note will accrue on the outstanding principal amount at the rate of zero percent per annum; thereafter, interest will accrue on the outstanding principal amount at the rate of 10.0% per annum, with such rate increasing in increments of 0.50% on each quarterly interest payment date. Upon consummation of the Tug Hill and XcL Midstream Acquisition, the loans outstanding under the Upstream Seller Note will be applied towards the cash consideration to be paid by the Company at the closing of the Tug Hill and XcL Midstream Acquisition and such loans will be extinguished. If, however, the Tug Hill and XcL Midstream Purchase Agreement is terminated and the Sellers are entitled pursuant to the terms of Section 13.2(b) of the A&R Purchase Agreement to, and elect to, retain the Deposit (as defined in the A&R Purchase Agreement), then the loans outstanding under the Upstream Seller Note would be applied towards the Sellers' receipt of the Deposit in accordance with Section 13.2(b) of the A&R Purchase Agreement and such loans would be extinguished.

The Tug Hill and XcL Midstream Purchase Agreement has an effective date of July 1, 2022. The closing of the pending Tug Hill and XcL Midstream Acquisition remains subject to regulatory approvals, including the termination or expiration of the applicable waiting periods under the HSR Act.

2022 Asset Acquisition

In the fourth quarter of 2022, the Company closed on the acquisition of approximately 4,600 net Marcellus acres in northeast Pennsylvania (the 2022 Asset Acquisition). The total purchase price for the acquisition was approximately $56 million. The 2022 Asset Acquisition was accounted for as an asset acquisition and, as such, the purchase price was allocated to property, plant and equipment.

Alta Acquisition

On July 21, 2021, the Company completed its acquisition (the Alta Acquisition) of Alta Marcellus Development, LLC and ARD Operating, LLC and subsidiaries (together, the Alta Target Entities), pursuant to that certain Membership Interest Purchase Agreement, dated May 5, 2021 (the Alta Purchase Agreement), by and among EQT Corporation, its indirect wholly-owned subsidiary EQT Acquisition HoldCo LLC, Alta Resources Development, LLC (Alta Resources) and the Alta Target Entities. The Alta Target Entities collectively held all of Alta Resources' upstream and midstream assets and liabilities. The purchase price for the Alta Acquisition consisted of approximately $1.0 billion in cash and 98,789,388 shares of EQT Corporation common stock, as adjusted pursuant to customary closing purchase price adjustments set forth in the Alta Purchase Agreement. The Alta Purchase Agreement has an effective date of January 1, 2021.

As a result of the Alta Acquisition, the Company acquired approximately 300,000 net Marcellus acres in northeast Pennsylvania, approximately 1.0 Bcfe per day of net production at the time of acquisition, approximately 300 miles of midstream gathering systems, approximately 100 miles of a freshwater system and a firm transportation portfolio to premium demand markets.

Allocation of Purchase Price. The Alta Acquisition was accounted for as a business combination using the acquisition method. The following table summarizes the purchase price and fair values of assets acquired and liabilities assumed as of July 21, 2021. The Company completed the purchase price allocation during the second quarter of 2022, at which time the value of the assets acquired and liabilities assumed were revised. The purchase accounting adjustments recorded in 2022 were not material to the Company's financial statements.

	Purchase Price Allocation	
	(Thousands)	
Consideration:		
Equity	$	1,925,405
Cash		1,000,000
Total consideration	$	2,925,405
Fair value of assets acquired:		
Cash and cash equivalents	$	43,199
Accounts receivable, net		159,539
Property, plant and equipment		3,145,630
Other assets		6,309
Amount attributable to assets acquired	$	3,354,677
Fair value of liabilities assumed:		
Accounts payable	$	131,214
Derivative instruments, at fair value		169,744
Other current liabilities		10,127
Other liabilities and credits		118,187
Amount attributable to liabilities assumed	$	429,272

The fair value of the acquired natural gas and oil properties was 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 acquired undeveloped properties was primarily 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 timing and amount of future development from a market participant perspective.

The fair value of the acquired midstream gathering systems was measured primarily using the cost approach based on inputs that are not observable in the market and, as such, are considered Level 3 fair value measurements. Significant inputs include replacement costs for similar assets, relative age of the acquired assets and any potential economic or functional obsolescence associated with the acquired assets.

See Note 4 for a description of the fair value hierarchy.

Post-Acquisition Operating Results. The Alta Target Entities contributed the following to the Company's consolidated results.

	July 21, 2021 through December 31, 2021
	(Thousands)
Sales of natural gas, NGLs and oil	$ 725,807
Loss on derivatives	(168,017)
Net marketing services and other	7,284
Total operating revenues	$ 565,074
Net income	$ 233,254

Unaudited Pro Forma Information. The table below summarizes the Company's results as though the Alta Acquisition had been completed on January 1, 2020. Certain of the Alta Target Entities' historical amounts were reclassified to conform to the Company's financial presentation of operations. The following unaudited pro forma information is provided for informational purposes only and does not represent what consolidated results of operations would have been had the Alta Acquisition occurred on January 1, 2020 nor are they necessarily indicative of future consolidated results of operations.

	Years Ended December 31,	
	2021	2020
	(Thousands, except per share amounts)	
Pro forma sales of natural gas, NGLs and oil	$ 7,248,870	$ 3,092,762
Pro forma (loss) gain on derivatives	(3,902,076)	501,910
Pro forma net marketing services and other	40,491	17,737
Pro forma total operating revenues	$ 3,387,285	$ 3,612,409
Pro forma net loss	$ (1,119,168)	$ (931,195)
Pro forma net income (loss) attributable to noncontrolling interest	1,246	(10)
Pro forma net loss attributable to EQT Corporation	$ (1,120,414)	$ (931,185)
Pro forma loss per share (basic)	$ (3.47)	$ (3.57)
Pro forma loss per share (diluted)	$ (3.47)	$ (3.57)

Reliance Asset Acquisition

On April 1, 2021, the Company closed on the acquisition of certain oil and gas assets (the Reliance Asset Acquisition) from Reliance Marcellus, LLC (Reliance), pursuant to the Company's exercise of a preferential purchase right that was triggered by Northern Oil and Gas, Inc.'s acquisition of Reliance's Marcellus assets. The total purchase price for the acquisition was approximately $69 million, and the assets acquired consisted of approximately 40 MMcfe per day of production at the time of acquisition and 4,100 net acres located in southwest Pennsylvania. The Reliance Asset Acquisition was accounted for as an asset acquisition and, as such, the purchase price was allocated to property, plant and equipment.

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 were producing approximately 450 net MMcfe per day at the time of acquisition, and approximately 100 work-in-process wells at various stages in the development cycle. The Chevron Acquisition also included a 31% investment in Laurel Mountain Midstream, LLC (LMM), which owns gathering assets that are operated by The Williams Companies, Inc., and two water systems that provide both fresh and produced water handling capabilities.

Allocation of Purchase Price. The Chevron Acquisition was accounted for as a business combination using the acquisition method. The following table summarizes the purchase price and the fair values of assets acquired and liabilities assumed in the Chevron Acquisition as of November 30, 2020. The Company completed the purchase price allocation during the fourth quarter of 2021, at which time the value of the assets acquired and liabilities assumed were revised. The purchase accounting adjustments recorded in 2021 were not material.

		Purchase Price Allocation
		(Thousands)
Consideration:		
Cash (a)	$	701,985
Settlement of pre-existing relationships		6,645
Total consideration	$	708,630
Fair value of assets acquired:		
Prepaid expenses and other	$	10,583
Net property, plant and equipment		725,319
Other assets		97,247
Amount attributable to assets acquired	$	833,149
Fair value of liabilities assumed:		
Accounts payable	$	3,347
Other current liabilities		18,410
Deferred income taxes		951
Other liabilities and credits (b)		101,811
Amount attributable to liabilities assumed	$	124,519

(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 includes liabilities due to minimum volume commitment (MVC) contracts as well as liabilities for asset retirement obligations and environmental obligations.

The fair value of the acquired natural gas and oil properties was 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 was 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 in 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 was 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 volume and market participant cost of debt.

7. Asset 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 (gain) loss/impairment on sale/ exchange of long-lived assets in the Statement of Consolidated Operations for the year ended December 31, 2020.

The fair value of leases acquired 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. The key assumption used in the fair value calculations included market-based prices for comparable acreage.

8. 2020 Divestiture

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 then-outstanding term loan facility.

The purchase and sale agreement for the 2020 Divestiture provided for additional cash bonus payments (the Contingent Consideration) payable to the Company of up to $20 million. Such Contingent Consideration was 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 represented an embedded derivative that was recorded at fair value in the Consolidated Balance Sheets. During the years ended December 31, 2022, 2021 and 2020, the Company received cash from the Contingent Consideration of $8.5 million, $10.6 million and $0.9 million, respectively. Changes in fair value were recorded in (gain) loss/impairment on sale/exchange of long-lived assets in the Statements of Consolidated Operations. The fair value of the Contingent Consideration was based on significant inputs that are interpolated from observable market data and, as such, was 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 (gain) loss/impairment on sale/exchange of long-lived assets in the Statement of Consolidated Operations during the year ended December 31, 2020.

9. Income Taxes

The following table summarizes the Company's income tax (benefit) expense.

	Years Ended December 31,		
	2022	2021	2020
		(Thousands)	
Current:			
Federal	$ 651	$ 911	$ (132,625)
State	18,457	(1,478)	(10,393)
Subtotal	19,108	(567)	(143,018)
Deferred:			
Federal	527,539	(316,364)	(129,131)
State	7,073	(111,106)	(23,144)
Subtotal	534,612	(427,470)	(152,275)
Total income tax expense (benefit)	$ 553,720	$ (428,037)	$ (295,293)

For the year ended December 31, 2022, the current income tax expense related primarily to state income tax liabilities. For the year ended December 31, 2021, the current income tax benefit related primarily to the sale of state research and development credits. For the year ended December 31, 2020, the current income tax benefit consisted primarily of federal 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 under the Coronavirus Aid, Relief and Economic Security Act (CARES Act). The remainder of the tax benefit of $26 million, including interest, was related to federal and state audits that were settled in 2020.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 (IRA). The IRA establishes a 15% corporate alternative minimum tax for certain corporations and a 1% excise tax on stock repurchases made by publicly traded U.S. corporations. The IRA also includes new and renewed options for energy credits. These changes are effective for tax years beginning after December 31, 2022. The Company is evaluating the impact these changes will have on its financial statements and disclosures.

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.

Income tax expense (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,					
	2022		2021		2020	
	Amount	Rate	Amount	Rate	Amount	Rate
	(Thousands)		(Thousands)		(Thousands)	
Income (loss) before income taxes	$ 2,334,662		$ (1,569,538)		$ (1,254,102)	
Tax at statutory rate	$ 490,279	21.0 %	$ (329,603)	21.0 %	$ (263,361)	21.0 %
State income taxes	48,970	2.1 %	(100,026)	6.4 %	(73,976)	5.9 %
Valuation allowance	12,685	0.5 %	9,616	(0.6)%	106,548	(8.5)%
Convertible debt repurchase premium	35,957	1.5 %	—	— %	—	— %
State law change	(49,511)	(2.1)%	(8,496)	0.5 %	—	— %
Tax settlements	—	— %	—	— %	(33,384)	2.7 %
Federal and state tax credits	(4,319)	(0.2)%	(3,079)	0.2 %	(11,628)	0.9 %
Other	19,659	0.8 %	3,551	(0.2)%	(19,492)	1.6 %
Income tax expense (benefit)	$ 553,720	23.7 %	$ (428,037)	27.3 %	$ (295,293)	23.5 %

The Company's effective tax rate for the year ended December 31, 2022 was higher compared to the U.S. federal statutory rate due primarily to state taxes, including valuation allowances limiting certain state tax benefits and nondeductible repurchase premiums on the Convertible Notes partly offset with state tax benefits relating to Pennsylvania tax legislation enacted on July 8, 2022 (Pennsylvania tax legislation). The Pennsylvania tax legislation lowers the corporate net income tax rate from 9.99% to 8.99% in 2023 and by 0.5% thereafter until the corporate net income tax rate reaches 4.99% in 2031. Included in the state law change above is a decrease in state net operating loss (NOL) carryforwards of $214.1 million and a decrease in state valuation allowance on NOL carryforwards of $198.5 million. The Company's effective tax rate for the year ended December 31, 2021 was higher compared to the U.S. federal statutory rate due primarily to state taxes, partly offset by valuation allowances that limit certain federal and state tax benefits as well as the West Virginia tax legislation enacted on April 13, 2021 that changed the way taxable income is apportioned in West Virginia for tax years beginning on or after January 1, 2022. 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 following table summarizes the source and tax effects of temporary differences between financial reporting and tax bases of assets and liabilities.

	December 31,	
	2022	2021
	(Thousands)	
Deferred tax assets:		
NOL carryforwards	$ 580,188	$ 948,707
Net unrealized losses	171,697	456,751
Federal and state capital loss carryforward	99,837	32,706
Federal tax credits	88,015	83,244
Alternative minimum tax credit carryforward	81,237	81,237
Investment in Equitrans Midstream	—	69,159
Incentive compensation and deferred compensation plans	14,586	20,409
Other	6,001	2,499
	1,041,561	1,694,712
Valuation allowance	(365,140)	(550,967)
Net deferred tax asset	676,421	1,143,745
Deferred tax liabilities:		
Property, plant and equipment	(2,118,827)	(2,051,051)
Net deferred tax liability	$ (1,442,406)	$ (907,306)

During 2022, net deferred tax liability increased by $535.1 million compared to 2021 due primarily to unrealized mark to market gains on unsettled commodities hedges, NOL utilization for federal and state, and accelerated cost recovery of property, plant and equipment partially offset by a reduction in state NOLs and valuation allowance primarily related to the Pennsylvania tax legislation.

The following table details the expiration periods of the NOL carryforward deferred tax assets presented above and associated valuation allowance by jurisdiction.

	December 31,	
	2022	2021
	(Thousands)	
NOL carryforwards:		
Federal (expires between 2035 and 2037)	$ 62,931	$ 244,032
Federal (indefinite expiration)	202,711	189,948
State (expires between 2027 and 2037)	299,933	500,676
State (indefinite expiration)	14,613	14,051
Total NOL carryforwards	$ 580,188	$ 948,707
Valuation allowance on NOL carryforwards:		
Federal	$ (23,626)	$ (22,848)
State	(241,638)	(426,243)
Total valuation allowance on NOL carryforwards	$ (265,264)	$ (449,091)

The remaining valuation allowance not presented in the table above primarily relates to the Company's investment in Equitrans Midstream which is a capital asset for tax purposes. Any capital losses from the sale of the investment can only be utilized to offset capital gains and are limited to being carried back 3 years and forward 5 years for potential utilization. In 2022, the Company sold the remaining portion of its investment in Equitrans Midstream, which generated a capital loss that can only be carried forward for potential future utilization. In 2021, the Company incurred an unrealized gain when adjusting the investment to fair value and sold a portion of its investment in Equitrans Midstream generating a capital loss that can be partially carried back to offset capital gains recognized in an earlier year, with the remainder being carried forward. For the period ending December 31, 2022, the Company has a valuation allowance related to the capital loss carryforward totaling

$52.7 million for federal income tax and $47.1 million for state income tax purposes due to the limitations on future potential utilization. For the period ending December 31, 2021, the Company has a valuation allowance related to the capital loss carryforward and any unrealized losses on its investment in Equitrans Midstream totaling $44.0 million for federal income tax and $57.5 million for state income tax purposes due to the limitations on future potential utilization.

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, 2022 and 2021, 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, the uncertainty of future commodity prices and inability to generate capital gains. A review of positive and negative evidence regarding these tax benefits resulted in the conclusion that valuation allowances for certain NOLs and capital loss carryforwards were warranted as it was more likely than not that the Company would not use them prior to expiration.

The Company intends to maintain a valuation allowance on certain of its state NOL carryforwards until there is sufficient evidence to support a reversal of all or a portion of such allowance. However, given the Company's anticipated future earnings, the Company believes that there is a reasonable possibility that, in the near term, sufficient positive evidence may become available that supports the release of a portion of the Company's valuation allowance, which would result in the recognition of certain state NOL carryforwards and a decrease to income tax expense for the period in which the release is recorded. The exact timing and amount of the valuation allowance release would be subject to change based on the level of profitability that the Company can achieve.

The following table reconciles the beginning and ending amount of reserve for uncertain tax positions, excluding interest and penalties.

	2022	2021	2020
		(Thousands)	
Balance at January 1	$ 182,032	$ 175,213	$ 259,588
Additions for tax positions taken in current year	9,612	4,969	5,470
Additions for tax positions taken in prior years	12,391	1,850	7,250
Reductions for tax positions taken in prior years	—	—	(38,859)
Reductions for tax positions settled with tax authorities	—	—	(58,236)
Balance at December 31	$ 204,035	$ 182,032	$ 175,213

The following table shows specific line items that are included in the reserve for uncertain tax positions.

	December 31,		
	2022	2021	2020
		(Thousands)	
If recognized, affect the effective tax rate	$ 117,341	$ 97,783	$ 91,003
Recorded in Consolidated Balance Sheets as reduction of related deferred tax asset for general business credit carryforwards and NOLs	$ 110,744	$ 97,160	$ 90,341

During 2020, the Company adjusted its tax reserves as a result of settling its 2010 to 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.

The Company recognizes interest and penalties related to unrecognized tax benefits in income tax expense. The Company recorded interest and penalties expense (income) of approximately $6.7 million, $4.2 million and $(3.8) million for the years ended December 31, 2022, 2021 and 2020, respectively. Interest and penalties of $22.2 million and $15.5 million were included in the Consolidated Balance Sheets at December 31, 2022 and 2021, respectively.

As of December 31, 2022, the Company believed that, as a result of potential settlements with relevant taxing authorities it is reasonably possible that a decrease of $125.9 million in unrecognized tax benefits related to federal tax positions may be necessary within twelve months.

In January of 2023, the Company settled its consolidated U.S. federal income tax liability with the IRS through 2017 at amounts included in the reserve above with minimal impacts to the effective tax rate. The settlement will result in an immaterial cash tax payment and a reduction in liabilities and deferred tax assets of $81.2 million and foregone R&D tax credits of $44.7 million reflected in the table above. Periodically, the Company is also the subject of various state income tax examinations. As of December 31, 2022, with few exceptions, the Company is no longer subject to state examinations by tax authorities for years prior to 2015.

There were no material changes to the Company's methodology for accounting for unrecognized tax benefits during 2022.

10. Debt

The table below summarizes the Company's outstanding debt.

	December 31, 2022			December 31, 2021		
	Principal Value	Carrying Value (a)	Fair Value (b)	Principal Value	Carrying Value (a)	Fair Value (b)
	(Thousands)					
Senior notes:						
3.00% notes due October 1, 2022	$ —	$ —	$ —	$ 568,823	$ 567,909	$ 576,969
7.42% series B notes due 2023	10,000	10,000	10,110	10,000	10,000	10,327
6.125% notes due February 1, 2025 (c)	911,467	908,168	915,833	1,000,000	994,643	1,133,000
5.678% notes due October 1, 2025	500,000	496,578	500,370	—	—	—
1.75% convertible notes due May 1, 2026	414,832	406,796	967,728	499,991	487,543	854,985
3.125% notes due May 15, 2026	440,857	436,198	408,454	500,000	493,157	516,265
7.75% debentures due July 15, 2026	115,000	113,218	124,874	115,000	112,721	138,504
3.90% notes due October 1, 2027	1,233,008	1,227,582	1,152,875	1,250,000	1,243,340	1,344,688
5.700% notes due April 1, 2028	500,000	493,941	505,325	—	—	—
5.00% notes due January 15, 2029	327,101	322,956	313,173	350,000	344,835	389,428
7.000% notes due February 1, 2030 (c)	714,800	710,138	752,670	750,000	744,417	966,983
3.625% notes due May 15, 2031	465,165	459,070	406,205	500,000	492,669	523,620
Note payable to EQM	94,320	94,320	95,667	99,838	99,838	117,837
Total debt	5,726,550	5,678,965	6,153,284	5,643,652	5,591,072	6,572,606
Less: Current portion of debt (d)	430,668	422,632	983,758	1,074,332	1,060,970	1,439,165
Long-term debt	$5,295,882	$5,256,333	$5,169,526	$4,569,320	$4,530,102	$5,133,441

(a) For the Company's credit facility and 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 approximates fair value as the interest rate is based on prevailing market rates; therefore, it is a Level 1 fair value measurement. For the Company's 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) Interest rates for this tranche of the Company's senior notes fluctuate based on changes to the credit ratings assigned to the Company's senior notes by Moody's, S&P and Fitch.
(d) As of December 31, 2022, the current portion of debt includes the 7.42% series B notes, the 1.75% convertible notes and a portion of the note payable to EQM. As of December 31, 2021, the current portion of debt includes the 3.00% notes, the 1.75% convertible notes and a portion of the note payable to EQM.

Credit Facility. The Company has a $2.5 billion credit facility. On June 28, 2022, the Company entered into the Third Amended and Restated Credit Agreement (the Third Amendment) with the lenders party thereto and PNC Bank, National Association, as administrative agent, swing line lender and L/C issuer, amending and restating the Second Amended and Restated Credit Agreement, dated as of July 31, 2017 (the Credit Agreement). The Third Amendment, among other things, (i) extends the maturity date of the commitments and loans under the Credit Agreement to June 28, 2027 and provides, at the

Company's option, two one-year extensions thereafter, subject to the approval of the lenders, (ii) allows for commitment increases of up to $500 million, subject to the agreement of the Company and new or existing lenders and (iii) allows for Base Rate Loans, Term SOFR Rate Loans, Daily Simple SOFR Loans and Swing Line Loans (each defined in the Third Amendment). Base Rate Loans bear interest at a Base Rate (as defined in the Third Amendment) plus a margin based on the Company's then current credit ratings.

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 a large group of financial institutions, each of which is obligated to fund its pro-rata portion of any borrowings by the Company. No one lender of the large group of financial institutions in the syndicate for the 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 the Company's exposure to disruption or consolidation in the banking industry.

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 lenders 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 of no greater than 65%. As of December 31, 2022, the Company was in compliance with all debt provisions and covenants.

The Company had approximately $25 million and $440 million of letters of credit outstanding under its credit facility as of December 31, 2022 and 2021, respectively.

Under the Company's credit facility, for the years ended December 31, 2022, 2021 and 2020, the maximum amounts of outstanding borrowings were $1.3 billion, $1.7 billion and $0.7 billion, respectively, the average daily balances were approximately $466 million, $609 million and $148 million, respectively, and interest was incurred at weighted average annual interest rates of 2.8%, 1.9% and 2.3%, respectively. For the years ended December 31, 2022, 2021 and 2020, the Company incurred commitment fees of approximately 20, 28 and 28 basis points, respectively, on the undrawn portion of its credit facility to maintain credit availability.

Senior Notes. 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. Certain of the Company's senior notes also include an offer to repurchase provision applicable upon the occurrence of certain change of control events specified in the applicable indentures. Interest rates on the Company's senior notes due February 1, 2025 and senior notes due February 1, 2030 fluctuate based on changes to the credit ratings assigned to the Company's senior notes by Moody's, S&P and Fitch. Interest rates on the Company's other outstanding senior notes do not fluctuate.

As of December 31, 2022, aggregate maturities for the Company's senior notes were $10 million in 2023, zero in 2024, $1,411 million in 2025, $971 million in 2026, $1,233 million in 2027 and $2,007 million thereafter.

5.678% Senior Notes and 5.700% Senior Notes. On October 4, 2022, the Company issued $500 million aggregate principal amount of 5.678% senior notes due October 1, 2025 and $500 million aggregate principal amount of 5.700% senior notes due April 1, 2028. The Company intends to use the net proceeds from the sale of the notes of $989.9 million (after deducting offering costs of $10.1 million) to partly fund the Tug Hill and XcL Midstream Acquisition. The covenants of the 5.678% senior notes and 5.700% senior notes are consistent with the Company's existing senior unsecured notes. The 5.678% senior notes and 5.700% senior notes have a special mandatory redemption provision that provides that if the consummation of the Tug Hill and XcL Midstream Acquisition does not occur on or before June 30, 2023 or if the Company notifies the trustee of the notes that it will not pursue consummation of the Tug Hill and XcL Midstream Acquisition, the Company is required to redeem the notes of each series then outstanding at a price equal to 101% of the principal amount of the notes to be redeemed plus accrued and unpaid interest to, but excluding, the redemption date.

Debt Repayments. The Company redeemed or repurchased the following debt during the year ended December 31, 2022.

Debt Tranche	Principal	Premiums/ (Discounts)	Accrued but Unpaid Interest	Total Cost
		(Thousands)		
3.00% notes due October 1, 2022	$ 568,823	$ 5,546	$ 7,150	$ 581,519
6.125% notes due February 1, 2025	88,533	3,064	2,691	94,288
1.75% convertible notes due May 1, 2026	85,096	127,906	250	213,252
3.125% notes due May 15, 2026	59,143	(3,998)	524	55,669
3.90% notes due October 1, 2027	16,992	(753)	195	16,434
5.00% notes due January 15, 2029	22,899	(1,039)	350	22,210
7.000% notes due February 1, 2030	35,200	1,978	934	38,112
3.625% notes due May 15, 2031	34,835	(5,341)	556	30,050
Total	$ 911,521	$ 127,363	$ 12,650	$ 1,051,534

Term Loan Facility and Bridge Loan Facility. In connection with entering into the Tug Hill and XcL Midstream Purchase Agreement, on September 6, 2022, the Company entered into a debt commitment letter, which was amended and restated on September 20, 2022. Pursuant to such amended and restated debt commitment letter, Royal Bank of Canada, PNC Bank, National Association, Mizuho Bank, Ltd. and certain other financial institutions committed to provide the Company with an unsecured bridge loan facility in an aggregate principal amount of $1.25 billion (the Bridge Loan Facility) and an unsecured term loan facility in an aggregate principal amount of $1.25 billion (the Term Loan Facility), subject to satisfaction of standard conditions.

On November 9, 2022, the Company entered into a Credit Agreement (the Term Loan Credit Agreement) with PNC Bank, National Association, as administrative agent and the other lenders parties thereto, under which the Company may obtain unsecured term loans in a single draw in an aggregate principal amount up to $1.25 billion to partially finance the Tug Hill and XcL Midstream Acquisition. On December 23, 2022, the Company amended the Term Loan Credit Agreement to extend the termination date for commitments under the Term Loan Facility to June 30, 2023. As of December 31, 2022, the Term Loan Facility commitments thereunder remained undrawn. The Company will incur commitment fees of approximately 20 basis points on the undrawn portion of the Term Loan Facility to maintain credit availability.

In connection with the closing of the offering of the Company's 5.678% senior notes and 5.700% senior notes on October 4, 2022, the commitments under the Bridge Loan Facility were automatically reduced by $989.9 million (the net proceeds from the sale of the notes) in accordance with the terms of the Bridge Loan Facility. The remaining commitments under the Bridge Loan Facility were terminated by the Company on December 23, 2022, as the Company determined that the remaining commitments were no longer necessary to finance the Tug Hill and XcL Midstream Acquisition.

Note Payable to EQM. EQM owns a preferred interest in EQT Energy Supply, LLC, a subsidiary of the Company, that is accounted for as a note payable due to the terms of the operating agreement of EQT Energy Supply, LLC. Principal amounts due for the note payable to EQM are $5.8 million in 2023, $6.3 million in 2024, $6.5 million in 2025, $6.9 million in 2026, $7.3 million in 2027 and $61.5 million thereafter.

Surety Bonds. The Company had approximately $180 million and $245 million of surety bonds outstanding as of December 31, 2022 and 2021, respectively, which were issued pursuant to contractual requirements as a result of the Company's then-existing credit ratings by Moody's, S&P and Fitch.

Convertible Notes. In April 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.

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 as long as the last reported price of EQT Corporation 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 (the Sale Price Condition);

- 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 Corporation 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.

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 Corporation 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 was 66.6667 shares of EQT Corporation common stock per $1,000 principal amount of the Convertible Notes, which was equivalent to an initial conversion price of $15.00 per share of EQT Corporation common stock. The initial conversion price represents a premium of 20% to the $12.50 per share closing price of EQT Corporation 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.

As a result of the cash dividends EQT Corporation paid on its common stock during 2022, the conversion rate for the Convertible Notes was adjusted as noted in the following table. Future dividend payments by EQT Corporation will result in further adjustments to the conversion rate per share of EQT Corporation common stock.

Dividend Paid	Effective Date of Adjustment to Conversion Rate	Conversion Shares of EQT Corporation Common Stock per $1,000 Principal Amount
Q1 2022	February 11, 2022	67.0535
Q2 2022	May 10, 2022	67.2836
Q3 2022	August 8, 2022	67.5232
Q4 2022	November 8, 2022	67.7532

The Sale Price Condition for conversion of the Convertible Notes was satisfied as of December 31, 2022 and December 31, 2021, and, accordingly, holders of the Convertible Notes could convert any of their Convertible Notes at their option at any time during the first quarter of 2023 and 2022, respectively, subject to the terms and conditions set forth in the Convertible Notes indenture. Therefore, as of December 31, 2022 and December 31, 2021, the net carrying value of the Convertible Notes was included in current portion of debt in the Consolidated Balance Sheets.

The following table summarizes Convertible Notes conversion right exercises from issuance through February 10, 2023. The Company elected to settle all such conversions by issuing to the converting holders shares of EQT Corporation common stock.

Settlement Month	Principal Converted	Shares Issued	Average Conversion Price
	(Thousands)		
September 2021	$ 9	599	$ 19.64
March 2022	8	536	33.65
April 2022	26	1,742	34.78
July 2022	5	335	36.91
October 2022	11	741	40.07
December 2022	6	405	36.66
January 2023	7	473	33.70

Upon conversion of the remaining outstanding Convertible Notes, the Company may satisfy its conversion obligation by paying and/or delivering at the Company's election, in the manner and subject to the terms and conditions provided in the Convertible Notes indenture, cash, shares of EQT Corporation common stock or a combination thereof. The Company intends to use a combined settlement approach to satisfy its obligation by paying or delivering to holders of the Convertible Notes cash equal to the principal amount of the obligation and EQT Corporation common stock for amounts that exceed the principal amount of the obligation.

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 Corporation 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 Corporation common stock and an initial capped price of $18.75 per share of EQT Corporation common stock, each of which are subject to certain customary adjustments, including adjustments as a result of the Company paying a dividend on its common stock.

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 of $32.5 million was recorded as a reduction to equity and will not be remeasured.

Based on the closing stock price of EQT Corporation common stock of $33.83 on December 31, 2022 and excluding the impact of the Capped Call Transactions, the if-converted value of the Convertible Notes exceeded the principal amount by $536 million.

The table below summarizes the net carrying value of the Convertible Notes.

	December 31, 2022	December 31, 2021
	(Thousands)	
Principal	$ 414,832	$ 499,991
Less: Unamortized debt issuance costs	8,036	12,448
Net carrying value of Convertible Notes	$ 406,796	$ 487,543

The table below summarizes the components of interest expense related to the Convertible Notes. The effective interest rate for the Convertible Notes is 2.4%.

	Years Ended December 31,		
	2022	2021	2020
	(Thousands)		
Contractual interest expense	$ 8,006	$ 8,750	$ 5,906
Amortization of issuance costs	2,522	2,695	1,777
Total Convertible Notes interest expense	$ 10,528	$ 11,445	$ 7,683

Debt Repayments. The Company redeemed or repurchased the following debt during the period January 1, 2023 through February 10, 2023.

Debt Tranche	Principal	Premiums/ (Discounts)	Accrued but Unpaid Interest	Total Cost
	(Thousands)			
6.125% notes due February 1, 2025	$ 9,946	$ 86	$ 268	$ 10,300
3.125% notes due May 15, 2026	47,942	(3,042)	296	45,196
3.90% notes due October 1, 2027	63,505	(3,534)	781	60,752
5.00% notes due January 15, 2029	8,607	(309)	137	8,435
7.000% notes due February 1, 2030	40,000	2,736	1,313	44,049
3.625% notes due May 15, 2031	30,000	(4,011)	167	26,156
Total	$ 200,000	$ (8,074)	$ 2,962	$ 194,888

11. Common Stock

As of December 31, 2022, the Company had reserved 18.9 million shares of authorized and unissued EQT Corporation common stock for stock compensation plans and approximately 40 million shares of authorized and unissued EQT Corporation common stock for settlement of the Convertible Notes.

In December 2021, the Company announced that the Board of Directors approved a share repurchase program to repurchase shares of its common stock for an aggregate purchase price up to $1 billion, excluding fees, commissions and expenses. In September 2022, the Company announced that the Board of Directors approved a $1 billion increase to the share repurchase program previously announced, pursuant to which the Company is authorized to repurchase shares of its common stock for an aggregate purchase price of up to $2 billion, excluding fees, commissions and expenses. The share repurchase authority is valid through December 31, 2023.

The following table presents the shares of EQT Corporation common stock repurchased under this share repurchase program through December 31, 2022.

	Shares of EQT Corporation Common Stock Repurchased	Aggregate Purchase Price (a)	Average Price Per Share (a)
		(Millions)	
Year Ended December 31, 2021	1,361,668	$ 29.4	$ 21.56
Year Ended December 31, 2022	13,139,641	392.7	29.89
Total	14,501,309	$ 422.1	

(a) Excludes fees and broker commissions.

In July 2021, the Company issued 98,789,388 shares of EQT Corporation common stock as part of the consideration for the Alta Acquisition described in Note 6.

In October 2020, the Company entered into an underwriting agreement under which the Company sold 20,000,000 shares of EQT Corporation 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**.**

During the period January 1, 2023 through February 10, 2023, the Company repurchased 5,906,159 shares of EQT Corporation common stock for approximately $200 million excluding fees and broker commissions.

12. Share-Based Compensation Plans

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

	Years Ended December 31,		
	2022	2021	2020
		(Thousands)	
Incentive Performance Share Unit Programs	$ 23,443	$ 15,386	$ 10,457
Restricted stock awards	23,028	19,217	10,480
Non-qualified stock options	221	550	848
Stock appreciation rights	17,406	9,183	2,724
Other programs, including non-employee director awards	3,313	3,171	3,040
Total share-based compensation expense (a)	$ 67,411	$ 47,507	$ 27,549

(a) For the years ended December 31, 2021 and 2020, share-based compensation expense of $4.7 million and $2.1 million, respectively, was included in other operating expenses related primarily to reorganization costs.

The Company typically elects to fund awards paid in stock through 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. Prior to 2023, the Company typically used treasury stock to fund awards paid in stock.

Cash received from exercises under all share-based payment arrangements for employees and directors for the year ended December 31, 2022 was $15.9 million. There was no cash received from exercises under all share-based payment arrangements for employees and directors for the years ended December 31, 2021 and 2020. During the years ended December 31, 2022, 2021 and 2020, share-based payment arrangements paid in stock generated tax benefits of $4.1 million, $1.3 million and $1.0 million, respectively. Cash paid for taxes related to net settlement of share-based incentive awards for the years ended December 31, 2022, 2021 and 2020 were $24.8 million, $3.8 million and $0.6 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 following programs:

- 2018 Incentive Performance Share Unit Program (2018 Incentive PSU Program) under the 2014 Long-Term Incentive Plan (LTIP);
- 2019 Incentive Performance Share Unit Program (2019 Incentive PSU Program) under the 2014 LTIP;
- 2020 Incentive Performance Share Unit Program (2020 Incentive PSU Program) under the 2019 LTIP;
- 2021 Incentive Performance Share Unit Program (2021 Incentive PSU Program) under the 2020 LTIP; and
- 2022 Incentive Performance Share Unit Program (2022 Incentive PSU Program) under the 2020 LTIP.

The programs noted above are collectively referred to as the Incentive PSU Programs. The 2020 Incentive PSU Program, 2021 Incentive PSU Program and 2022 Incentive PSU Program granted equity awards. The 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 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.

Executive performance incentive program awards granted in year 2020 are earned based on:
- adjusted well costs;
- adjusted free cash flow; and
- the level of total shareholder return relative to a predefined peer group.

Executive performance incentive program awards granted in year 2021 are earned based on:
- the level of absolute total shareholder return and total shareholder return relative to a predefined peer group.

Executive performance incentive program awards granted in year 2022 are earned based on:
- the level of absolute total shareholder return and total shareholder return relative to a predefined peer group; and
- the Company's performance in achieving its 2025 net zero Scopes 1 and 2 emissions target.

Prior to 2020, the payout factor for the Incentive PSU Programs varied 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 2021 Incentive PSU Program has a payout factor that ranges from zero to 200% and the 2022 Incentive PSU Program has a payout factor that ranges from zero to 220%. The Company recorded the 2020 Incentive PSU Program, the 2021 Incentive PSU Program, the 2022 Incentive PSU Program and the portion of the 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 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 December 31, 2019	615,293	$ 44.27		$ 27,239,021
Granted in Period	1,376,198	6.62		9,110,431
Granted from Multiplier	28,705	120.60		3,461,823
Vested	(73,278)	120.60		(8,837,327)
Forfeited	(7,190)	13.28		(95,483)
Outstanding at December 31, 2020	1,939,728	15.92		30,878,465
Granted in Period	922,260	23.44		21,617,774
Granted from Multiplier	61,076	76.53		4,674,146
Vested	(168,416)	76.53		(12,888,876)
Outstanding at December 31, 2021	2,754,648	16.08		44,281,509
Granted in Period	575,120	29.73	(b)	17,098,318
Granted from Multiplier	162,183	29.45		4,776,289
Vested	(625,563)	29.45		(18,422,830)
Forfeited	(4,398)	13.28		(58,405)
Outstanding at December 31, 2022	2,861,990	$ 16.66		$ 47,674,881

(a) For the years ended December 31, 2021 and 2020, the Company settled total shares of 9,550 and 7,020, respectively, for Equitrans Midstream employees.

(b) The 2022 Incentive PSU Program was granted as a liability award and converted to an equity award in April 2022. The fair value determined through a Monte Carlo simulation at the time of conversion totaled $75.32 per share, which was an increase of $45.59 per share from fair value determined through a Monte Carlo simulation at the grant date.

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

Incentive PSU Programs – Cash Settled	Nonvested Shares (a)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at December 31, 2019	452,410	$ 60.19	$ 27,230,558
Granted from Multiplier	60,123	120.60	7,250,834
Vested	(153,482)	120.60	(18,509,929)
Forfeited	(19,356)	61.43	(1,189,039)
Outstanding at December 31, 2020	339,695	43.52	14,782,424
Granted from Multiplier	32,350	76.53	2,475,746
Vested	(134,525)	76.53	(10,293,571)
Forfeited	(3,940)	29.45	(116,033)
Outstanding at December 31, 2021	233,580	29.32	6,848,566
Granted from Multiplier	81,753	29.32	2,396,998
Vested	(315,333)	29.32	(9,245,564)
Outstanding at December 31, 2022	—	$ —	$ —

(a) For the years ended 2021 and 2020, the Company settled total shares paid in cash of 84,697 and 40,018, respectively, for Equitrans Midstream employees.

Total capitalized compensation costs related to the Incentive PSU Programs for the years ended December 31, 2022, 2021 and 2020 were $0.6 million, $0.8 million and $0.9 million, respectively. As of December 31, 2022, $7.4 million and $29.8 million of unrecognized compensation cost (assuming no changes to the performance condition achievement level) related to the 2021 Incentive PSU Program and 2022 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,				
	2022	2021 (a)	2020 (b)	2019	2018
Risk-free rate	1.52%	0.18%	1.22%	2.44%	1.97%
Volatility factor	65.38%	72.50%	45.41%	54.60%	32.60%
Expected term	3 years	3 years	3 years	3 years	3 years

(a) There were two grant dates for the 2021 Incentive PSU Program. Amounts shown represent weighted average.
(b) There were three grant dates for the 2020 Incentive PSU Program. Amounts shown represent weighted average.

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.

Restricted Stock Unit Awards – Equity

The Company granted 1,288,430, 1,980,230 and 1,767,960 restricted stock unit equity awards to employees of the Company during the years ended December 31, 2022, 2021 and 2020, respectively. Awards are subject to a three-year graded vesting schedule commencing with the date of grant, assuming continued service through each vesting date. For the years ended December 31, 2022, 2021 and 2020, the weighted average fair value of these restricted stock unit grants, based on the grant date fair value of EQT Corporation common stock, was approximately $21.65, $13.92 and $10.02, respectively.

The total fair value of restricted stock unit equity awards vested during the years ended December 31, 2022, 2021 and 2020 was $16.6 million, $8.6 million and $3.2 million, respectively. Total capitalized compensation costs related to the restricted stock unit equity awards was $6.6 million, $6.7 million and $3.0 million for the years ended December 31, 2022, 2021 and 2020, respectively.

As of December 31, 2022, $15.7 million of unrecognized compensation cost related to nonvested restricted stock unit equity awards was expected to be recognized over a remaining weighted average vesting term of approximately 0.7 years.
The following table summarizes restricted stock unit equity award activity as of December 31, 2022.

Restricted Stock – Equity Settled	Nonvested Shares (a)	Weighted Average Fair Value	Aggregate Fair Value
Outstanding at January 1, 2021	1,868,400	$ 11.56	$ 21,594,314
Granted	1,980,230	13.92	27,563,546
Vested	(621,930)	13.85	(8,612,563)
Forfeited	(122,419)	12.16	(1,488,862)
Outstanding at December 31, 2021	3,104,281	12.58	39,056,435
Granted	1,288,430	21.65	27,893,331
Vested	(1,368,577)	12.16	(16,644,859)
Forfeited	(97,189)	15.56	(1,512,333)
Outstanding at December 31, 2022	2,926,945	$ 16.67	$ 48,792,574

(a) Shares vested during the year ended December 31, 2021 included 59,340 shares for an Equitrans Midstream employee that was settled by the Company.

Restricted Stock Unit Awards – Liability

The Company did not grant restricted stock unit awards to be paid in cash during the years ended December 31, 2022, 2021 and 2020. All outstanding restricted stock unit awards to be paid in cash had vested as of December 31, 2022.

Because these awards were liability awards, the Company recorded compensation expense based on the fair value of the awards as remeasured at the end of each reporting period. The restricted stock units granted fully vested at the end of the three-year period commencing with the date of grant, assuming continued service through each vesting date. The total liability recorded for these restricted stock units was $8.1 million and $4.5 million as of December 31, 2021 and 2020, 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 year ended December 31, 2020. 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 Corporation common stock at the time of grant. Expected volatilities are based on historical volatility of EQT Corporation common stock. The expected term represents the period of time that options granted are expected to be outstanding based on historical option exercise experience. There were no stock options granted in 2022 and 2021.

	Year Ended December 31, 2020
Risk-free interest rate	1.10 %
Dividend yield	— %
Volatility factor	60.00 %
Expected term	4 years
Number of Options Granted	1,000,000
Weighted Average Grant Date Fair Value	$ 1.61

As of December 31, 2022, $0.1 million of unrecognized compensation cost related to outstanding nonvested stock options was expected to be recognized by December 31, 2023. The total intrinsic value of options exercised during the year ended December 31, 2022 was $20.2 million. There were no stock option exercises in 2021 and 2020.

The following table summarizes option activity as of December 31, 2022.

Non-Qualified Stock Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2022	3,466,629	$ 23.31		
Exercised	(1,517,407)	26.83		
Expired	(365,586)	28.21		
Outstanding at December 31, 2022	1,583,636	18.81	3.8 years	$ 26,837,073
Exercisable at December 31, 2022	1,250,303	$ 21.16	3.7 years	$ 18,893,740

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 Corporation 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. Assumptions at grant date are 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 Corporation common stock at the reporting date. 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	$ —

As of December 31, 2022, $0.2 million of unrecognized compensation cost related to outstanding stock appreciation rights was expected to be recognized by December 31, 2023.

The following table summarizes stock appreciation rights activity as of December 31, 2022.

Stock Appreciation Rights	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2022	1,240,000	$ 10.00		
Granted	—	—		
Outstanding at December 31, 2022	1,240,000	10.00	7.0 years	$ 29,549,200
Exercisable at December 31, 2022	333,333	$ 10.00	7.0 years	$ 7,943,325

Non-employee Directors' Share-Based Awards

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 Corporation 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 granted prior to 2020 that are 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 Corporation 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 373,857 non-employee director share-based awards, including accrued dividends, were outstanding as of December 31, 2022. A total of 44,800, 120,080 and 201,300 share-based awards were granted to non-employee directors during the years ended December 31, 2022, 2021 and 2020, respectively. The weighted average fair value of these grants, based on the closing price of EQT Corporation common stock on the business day prior to the grant date, was $43.97, $17.49 and $13.46 for the years ended December 31, 2022, 2021 and 2020, respectively.

2023 Awards

Effective in 2023, the Compensation Committee adopted the 2023 Incentive Performance Share Unit Program (2023 Incentive PSU Program) under the 2020 LTIP. The 2023 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 360,400 share units were granted under the 2023 Incentive PSU Program. The payout of the share units will vary between zero and 200% of the number of outstanding units contingent upon the Company's absolute total shareholder return and total shareholder return relative to a predefined peer group over the period of January 1, 2023 through December 31, 2025.

Effective in 2023, the Compensation Committee granted 916,680 restricted stock unit equity awards that will follow a three-year graded vesting schedule commencing with the date of grant, assuming continued employment through each vesting date. The share total includes the Company's "equity-for-all" program, instituted in 2021, pursuant to which the Company grants equity awards to all permanent full-time employees.

13. Commitments and Contingencies

Purchase Obligations

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, 2022 were $23.7 billion, composed of $1.8 billion in 2023, $1.7 billion in 2024, $2.0 billion in 2025, $1.7 billion in 2026, $1.6 billion in 2027 and $14.9 billion thereafter (primarily concentrated in 2028 through 2044).

In addition, the Company has commitments to pay for services and materials related to its operations, which primarily include minimum volume commitments to obtain water services and electric hydraulic fracturing services and commitments to purchase equipment, materials and sand. As of December 31, 2022, future commitments under these contracts were $627.3 million, composed of $176.1 million in 2023, $80.1 million in 2024, $87.8 million in 2025, $83.8 million in 2026, $56.6 million in 2027 and $142.9 million thereafter.

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, 2022.

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 description of what is deemed investment grade and a discussion of other factors, aside from credit ratings, that may affect margin deposit requirements on the Company's derivative contracts. See Note 10 for a discussion of letters of credit outstanding and surety bonds posted as of December 31, 2022.

Legal and Regulatory Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against the Company. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings.

The Company evaluates its legal proceedings, including litigation and regulatory and governmental investigations and inquiries, on a regular basis and accrues a liability for such matters when the Company believes that a loss is probable and the amount of the loss can be reasonably estimated. Any such accruals are adjusted thereafter as appropriate to reflect changed circumstances. In the event the Company determines that (i) a loss to the Company is probable but the amount of the loss cannot be reasonably estimated, or (ii) a loss to the Company is less likely than probable but is reasonably possible, then the Company is required to disclose the matter herein, although the Company is not required to accrue such loss.

When able, the Company determines an estimate of reasonably possible losses or ranges of reasonably possible losses, whether in excess of any related accrued liability or where there is no accrued liability, for legal proceedings. In instances where such estimates can be made, any such estimates are based on the Company's analysis of currently available information and are subject to significant judgment and a variety of assumptions and uncertainties and may change as new information is obtained.

The ultimate outcome of the matters described below, such as whether the likelihood of loss is remote, reasonably possible, or probable, or if and when the range of loss is reasonably estimable, is inherently uncertain. Furthermore, due to the inherent subjectivity of the assessments and unpredictability of outcomes of legal proceedings, any amounts accrued or estimated as possible losses may not represent the ultimate loss to the Company from the legal proceedings in question and the Company's exposure and ultimate losses may be higher, and possibly significantly so, than the amounts accrued or estimated.

Securities Class Action Litigation. On December 6, 2019, an amended putative class action complaint was filed in the United States District Court for the Western District of Pennsylvania by Cambridge Retirement System, Government of Guam Retirement Fund, Northeast Carpenters Annuity Fund, and Northeast Carpenters Pension Fund, on behalf of themselves and all those similarly situated, against EQT Corporation, and certain former executives and current and former board members of EQT Corporation (the Securities Class Action). The complaint alleges that certain statements made by EQT Corporation regarding its merger with Rice Energy Inc. in 2017 (the Rice Merger) were materially false and violated various federal securities laws. Pursuant to the complaint, the plaintiffs seek compensatory or rescissory damages in an unspecified amount for all damages allegedly sustained by the class as a result of alleged negative impacts to EQT Corporation's stock price in 2018 and 2019. This legal proceeding is currently in discovery and a trial date has not been determined.

Additionally, following the filing of the Securities Class Action complaint, several other lawsuits were filed in the United States District Court for the Western District of Pennsylvania and the Court of Common Pleas of Allegheny County, Pennsylvania by certain shareholders of EQT Corporation against EQT Corporation and certain former executives and current and former board members of EQT Corporation asserting substantially the same allegations as those raised in the Securities Class Action. These matters are currently pending, the majority of which have been stayed pending a ruling on dispositive motions in the Securities Class Action. The Company believes the claims asserted in the Securities Class Action and related litigation have no merit, but unpredictability is inherent in litigation and the Company cannot predict the outcomes with any certainty.

With respect to the matters described above, the Company is unable at this time to estimate the losses that are reasonably possible to be incurred or a range of such losses due to various factors, including that the proceedings are still in their early stages and discovery is not complete; the matters present meaningful legal uncertainties; and predicting the outcome depends on making assumptions about future decisions of courts and the behavior of other parties for which the Company does not currently have sufficient information. The matters described above contain certain information related to claims against the Company as alleged in pleadings. While information of this type may provide insight into the potential magnitude of a matter, it does not necessarily represent the Company's estimate of a probable or reasonably possible loss or the Company's judgment as to any currently appropriate accrual.

Regulatory and Environmental Matters. 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 $5.1 million was recorded in other liabilities and credits in the Consolidated Balance Sheet as of December 31, 2022.

Other Matters. In addition to the matters described above, the Company, in the normal course of business, is subject to various other pending and threatened legal proceedings in which claims for monetary damages or other relief are asserted. The Company does not anticipate, at the present time, that the ultimate aggregate liability, if any, arising out of such other legal proceedings will have a material adverse effect on the Company's financial position, results of operations or liquidity.

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. The Company does not depend on any single customer and believes that the loss of any one customer would not have an adverse effect on the Company's ability to sell its natural gas, NGLs and oil.

Approximately 91% and 90% of the Company's accounts receivable balances as of December 31, 2022 and 2021, 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, 2022, 2021 or 2020.

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, 2022, 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, 2022, 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 leases drilling rigs, facilities, vehicles and drilling and compression equipment.

To determine the present value of its right-of-use assets and lease liabilities, 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, *Leases*, 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 payments for property taxes and other operating and maintenance expenses and payments based on asset use, which are not included in the 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 obligation is included in the present value of the right-of-use asset and lease liability. As of December 31, 2022 and 2021, the Company was not a lessor.

The following table summarizes the Company's lease costs.

	Years Ended December 31,		
	2022	2021	2020
		(Thousands)	
Operating and finance lease costs	$ 21,638	$ 19,826	$ 28,286
Variable and short-term lease costs	13,726	11,516	15,922
Total lease costs (a)	$ 35,364	$ 31,342	$ 44,208

(a) Includes drilling rig lease costs capitalized to property, plant and equipment of $25.4 million, $22.1 million and $29.9 million, respectively, of which $17.7 million, $16.5 million and $19.9 million, respectively, were operating lease costs for the years ended December 31, 2022, 2021 and 2020.

For the years ended December 31, 2022, 2021 and 2020, cash paid for lease liabilities and reported in net cash provided by operating activities in the Statements of Consolidated Cash Flows was $10.3 million, $9.7 million and $10.4 million, respectively. For the years ended December 31, 2022 and 2021, cash paid for lease liabilities and reported in net cash (used in) provided by financing activities in the Statements of Consolidated Cash Flows was $1.8 million and $1.1 million, respectively. During the years ended December 31, 2022, 2021 and 2020, the Company recorded $23.4 million, $20.8 million and $18.9 million, respectively, of right-of-use assets in exchange for new lease liabilities. As of December 31, 2022, 2021 and 2020, the weighted average remaining lease term was 1.9 years, 2.6 years and 2.8 years, respectively. For the years ended December 31, 2022, 2021 and 2020, the weighted average discount rate was 4.4%, 2.9% and 3.3%, respectively.

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, 2022 and 2021, total right-of-use assets were $29.2 million and $26.1 million, respectively, and total lease liabilities were $48.0 million and $52.7 million, respectively, of which $35.4 million and $28.0 million, respectively, were classified as current.

During the fourth quarter of 2020, the Company recognized $22.8 million of right-of-use asset impairment in impairment of contract 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.

The following table summarizes the Company's lease payment obligations as of December 31, 2022.

	December 31, 2022
	(Thousands)
2023	$ 36,755
2024	8,643
2025	1,724
2026	1,043
2027	885
Thereafter	899
Total lease payment obligations	49,949
Less: Interest	1,931
Present value of lease liabilities	$ 48,018

16. 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.

	December 31,	
	2022	2021
	(Thousands)	
Capitalized costs		
Proved properties	$ 25,142,857	$ 23,117,987
Unproved properties	1,747,705	2,405,867
Total capitalized costs	26,890,562	25,523,854
Less: Accumulated depreciation and depletion	9,119,553	7,508,178
Net capitalized costs	$ 17,771,009	$ 18,015,676

	Years Ended December 31,		
	2022	2021	2020
	(Thousands)		
Costs incurred (a)			
Property acquisition:			
Proved properties (b)	$ 82,276	$ 2,286,386	$ 761,940
Unproved properties (c)	113,523	805,942	78,404
Exploration	3,438	24,403	5,484
Development	1,292,509	950,531	947,233

(a) Amounts exclude capital expenditures for facilities, information technology and other corporate items as well as the acquired midstream assets described in Note 6.

(b) Amounts in 2022 include $40.5 million for Marcellus leases acquired in the 2022 Asset Acquisition. Amounts in 2021 include $1,754.7 million and $450.0 million for Marcellus wells and leases, respectively, acquired in the Alta Acquisition and Reliance Asset Acquisition described in Note 6. Amounts in 2020 include $674.0 million and $6.5 million for Marcellus and Utica wells, respectively, acquired in the Chevron Acquisition.

(c) Amounts in 2022 include $17.1 million for unproved properties acquired in the 2022 Asset Acquisition. Amounts in 2021 include $743.3 million for unproved properties acquired in the Alta Acquisition. Amounts in 2020 include $38.9 million for unproved properties acquired in 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,		
	2022	2021	2020
	(Thousands)		
Sales of natural gas, NGLs and oil	$ 12,114,168	$ 6,804,020	$ 2,650,299
Transportation and processing	2,116,976	1,942,165	1,710,734
Production	300,985	225,279	155,403
Exploration	3,438	24,403	5,484
Depreciation and depletion	1,665,962	1,676,702	1,393,465
(Gain) loss/impairment on sale/exchange of long-lived assets	(8,446)	(21,124)	100,729
Impairment and expiration of leases	176,606	311,835	306,688
Income tax expense (benefit)	1,987,323	667,435	(254,671)
Results of operations from producing activities, excluding corporate overhead	$ 5,871,324	$ 1,977,325	$ (767,533)

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, an executive master's of business administration in energy from the University of Oklahoma and is a licensed professional engineer with 23 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 volume 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, 2022. 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.

The Company utilizes reliable technologies in the calculation of its proved undeveloped reserves. The technologies used in the estimation of the Company's proved undeveloped 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.

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,		
	2022	**2021**	**2020**
		(MMcf)	
Natural gas, NGLs and oil			
Proved developed and undeveloped reserves:			
Balance at January 1	24,961,499	19,802,092	17,469,394
Revision of previous estimates	(654,618)	(274,111)	(739,213)
Purchase of hydrocarbons in place	141,038	4,186,933	1,380,564
Sale of hydrocarbons in place	—	—	(256,663)
Extensions, discoveries and other additions	2,494,713	3,104,402	3,445,802
Production	(1,940,043)	(1,857,817)	(1,497,792)
Balance at December 31	25,002,589	24,961,499	19,802,092
Proved developed reserves:			
Balance at January 1	17,218,655	13,641,345	12,443,987
Balance at December 31	17,513,645	17,218,655	13,641,345
Proved undeveloped reserves:			
Balance at January 1	7,742,844	6,160,747	5,025,407
Balance at December 31	7,488,944	7,742,844	6,160,747

	Years Ended December 31,		
	2022	2021	2020
		(MMcf)	
Natural gas			
Proved developed and undeveloped reserves:			
Balance at January 1	23,523,665	18,865,013	16,677,202
Revision of previous estimates	(432,315)	(568,814)	(781,668)
Purchase of natural gas in place	141,038	4,186,933	1,209,326
Sale of natural gas in place	—	—	(254,930)
Extensions, discoveries and other additions	2,434,543	2,786,850	3,433,857
Production	(1,842,044)	(1,746,317)	(1,418,774)
Balance at December 31	23,824,887	23,523,665	18,865,013
Proved developed reserves:			
Balance at January 1	16,152,083	12,750,312	11,811,521
Balance at December 31	16,541,017	16,152,083	12,750,312
Proved undeveloped reserves:			
Balance at January 1	7,371,582	6,114,701	4,865,681
Balance at December 31	7,283,870	7,371,582	6,114,701

	Years Ended December 31,		
	2022	2021	2020
		(Mbbl)	
NGLs			
Proved developed and undeveloped reserves:			
Balance at January 1	225,792	148,762	126,955
Revision of previous estimates	(33,955)	46,868	6,825
Purchase of NGLs in place	—	—	25,879
Sale of NGLs in place	—	—	(289)
Extensions, discoveries and other additions	9,610	47,120	1,757
Production	(15,306)	(16,958)	(12,365)
Balance at December 31	186,141	225,792	148,762
Proved developed reserves:			
Balance at January 1	169,781	141,489	100,945
Balance at December 31	154,921	169,781	141,489
Proved undeveloped reserves:			
Balance at January 1	56,011	7,273	26,010
Balance at December 31	31,220	56,011	7,273

	Years Ended December 31,		
	2022	2021	2020
	(Mbbl)		
Oil			
Proved developed and undeveloped reserves:			
Balance at January 1	13,846	7,417	5,077
Revision of previous estimates	(3,095)	2,249	250
Purchase of oil in place	—	—	2,660
Sale of oil in place	—	—	—
Extensions, discoveries and other additions	418	5,805	234
Production	(1,027)	(1,625)	(804)
Balance at December 31	10,142	13,846	7,417
Proved developed reserves:			
Balance at January 1	7,981	7,016	4,466
Balance at December 31	7,183	7,981	7,016
Proved undeveloped reserves:			
Balance at January 1	5,865	401	611
Balance at December 31	2,959	5,865	401

The change in reserves during the year ended December 31, 2022 resulted from the following:

- Conversions of 1,365 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 2,495 Bcfe, which exceeded 2022 production of 1,940 Bcfe. Extensions, discoveries and other additions included an increase of 2,077 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2022 reserve development that expanded the number of the Company's proven locations and additions to the Company's five-year drilling plan and 418 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 1,625 Bcfe related to proved undeveloped locations that are no longer expected to be developed as proved reserves within five years of initial booking as a result of development schedule changes, driven largely by third-party impacts, which has pushed planned completion dates into a future period from when originally planned.
- Positive revisions to proved undeveloped locations of 518 Bcfe due primarily to changes in ownership interests.
- Positive revisions of 356 Bcfe primarily from proved developed locations as a result of positive curve revisions.
- Positive revisions of 96 Bcfe from higher pricing that impacted well economics.
- Purchase of hydrocarbons in place of 141 Bcfe from the 2022 Asset Acquisition described in Note 6.

The change in reserves during the year ended December 31, 2021 resulted from the following:

- Conversions of 1,634 Bcfe of proved undeveloped reserves to proved developed reserves.
- Extensions, discoveries and other additions of 3,104 Bcfe, which exceeded 2021 production of 1,858 Bcfe. Extensions, discoveries and other additions included an increase of 2,828 Bcfe of proved undeveloped additions associated with acreage that was previously unproved but became proved due to 2021 reserve development that expanded the number of the Company's proven locations, implementation of, and alignment with, the Company's combo-development strategy and additions to the Company's five-year drilling plan, 52 Bcfe from extension of proved undeveloped reserves lateral lengths and 224 Bcfe from converting unproved reserves to proved developed reserves.
- Negative revisions of 819 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.
- Negative revisions to proved undeveloped locations of 62 Bcfe due primarily to changes in working interests and net revenue interest.
- Negative revisions of 31 Bcfe primarily from proved developed locations as a result of negative curve revisions.
- Positive revisions of 638 Bcfe from higher pricing that impacted well economics.
- Purchase of hydrocarbons in place of 4,187 Bcfe from the Alta Acquisition and Reliance Asset Acquisition described in Note 6.

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 the Company's 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 the 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 from the Chevron Acquisition described in Note 6.
- Sale of hydrocarbons in place of 257 Bcfe due to the 2020 Divestiture described in Note 8.

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, 2022	December 31, 2021	December 31, 2020
	(Thousands)		
Future cash inflows (a)	$ 140,032,653	$ 70,844,136	$ 27,976,557
Future production costs (b)	(22,801,652)	(20,961,576)	(16,344,965)
Future development costs	(3,244,211)	(2,882,921)	(2,268,109)
Future income tax expenses	(26,375,241)	(10,433,091)	(1,820,341)
Future net cash flow	87,611,549	36,566,548	7,543,142
10% annual discount for estimated timing of cash flows	(47,547,025)	(19,285,424)	(4,176,684)
Standardized measure of discounted future net cash flows	$ 40,064,524	$ 17,281,124	$ 3,366,458

(a) The majority of the Company's production is sold through liquid trading points on interstate pipelines. Reserves were computed using average first-day-of-the-month closing prices for the prior twelve months less regional adjustments. Regional adjustments were calculated using historical average realized prices received in the Appalachian Basin. NGLs pricing was calculated using average first-day-of-the-month closing prices for the prior twelve months for NGLs components, adjusted using the regional component makeup of proved NGLs.

	December 31, 2022	December 31, 2021	December 31, 2020
Oil for West Texas Intermediate (WTI) ($/Bbl)	$ 94.14	$ 66.55	$ 39.54
Less regional adjustments ($/Bbl)	$ 17.31	$ 14.98	$ 18.60
Oil price ($/Bbl)	$ 76.83	$ 51.57	$ 20.94
Natural gas for NYMEX ($/MMBtu)	$ 6.357	$ 3.598	$ 1.985
Less regional adjustments ($/MMBtu)	$ 1.094	$ 1.040	$ 0.680
Natural gas price ($/Mcf)	$ 5.543	$ 2.694	$ 1.380
NGLs price ($/Bbl)	$ 38.66	$ 29.95	$ 11.97

(b) Includes approximately $2,098 million, $1,937 million and $1,554 million for future plugging and abandonment costs as of December 31, 2022, 2021 and 2020, respectively.

Holding production and development costs constant, an increase in NYMEX price of $0.10 per Dth for natural gas, an increase in WTI of $10 per barrel for NGLs and an increase in WTI of $10 per barrel for oil would result in a change in the December 31, 2022 discounted future net cash flows before income taxes of the Company's proved reserves of approximately $1,123 million, $764 million and $50 million, respectively.

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

	Years Ended December 31,		
	2022	2021	2020
	(Thousands)		
Net sales and transfers of natural gas and oil produced	$ (9,696,207)	$ (4,636,576)	$ (784,163)
Net changes in prices, production and development costs	35,353,172	17,290,913	(6,761,447)
Extensions, discoveries and improved recovery, net of related costs	1,798,851	46,078	714,808
Development costs incurred	902,925	764,002	797,796
Net purchase of minerals in place	280,233	3,491,441	350,075
Net sale of minerals in place	—	—	(226,497)
Revisions of previous quantity estimates	(299,423)	184,552	(324,415)
Accretion of discount	1,728,112	336,646	849,267
Net change in income taxes	(7,233,051)	(3,614,029)	152,978
Timing and other	(51,212)	51,639	105,383
Net increase (decrease)	22,783,400	13,914,666	(5,126,215)
Balance at January 1	17,281,124	3,366,458	8,492,673
Balance at December 31	$ 40,064,524	$ 17,281,124	$ 3,366,458

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 our Principal Executive Officer and Principal Financial Officer, an evaluation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the 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 our 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

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). Our internal control system is designed to provide reasonable assurance to management and our 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.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2022. 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 we maintained effective internal control over financial reporting as of December 31, 2022.

Ernst & Young LLP (Ernst & Young), the independent registered public accounting firm that audited our Consolidated Financial Statements, has issued an attestation report on our internal control over financial reporting. Ernst & Young's attestation report on our 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 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Not Applicable.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not Applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following information is incorporated herein by reference from our definitive proxy statement relating to the 2023 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2022:

- Information required by Item 401 of Regulation S-K with respect to directors;
- Information required by Item 405 of Regulation S-K with respect to our compliance with Section 16(a) of the Exchange Act, if any;
- Information required by Item 407(d)(4) of Regulation S-K with respect to disclosure of the existence of our separately-designated standing Audit Committee and the identification of the members of the Audit Committee; and
- Information required by Item 407(d)(5) of Regulation S-K with respect to disclosure of our Audit Committee financial expert.

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 16, 2023)."

We have 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. Our code of business conduct and ethics is posted on our 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. We intend to satisfy the disclosure requirement regarding certain amendments to, or waivers from, provisions of our code of business conduct and ethics by posting such information on our website.

Item 11. Executive Compensation

The following information is incorporated herein by reference from our definitive proxy statement relating to the 2023 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2022:

- Information required by Item 402 of Regulation S-K with respect to named executive officer and director compensation; and
- Information required by paragraphs (e)(4) and (e)(5) of Item 407 of Regulation S-K with respect to certain matters related to the Management Development and Compensation Committee of our Board of Directors.

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 from our definitive proxy statement relating to the 2023 annual meeting of shareholders, which is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2022.

Equity Compensation Plan Information

The following table and related footnotes provide information as of December 31, 2022 with respect to shares of our common stock that may be issued under our 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)	8,448,738 (2)	$ 14.94 (3)	18,034,298 (4)
Equity Compensation Plans Not Approved by Shareholders (5)	52,518 (6)	N/A	115,089 (7)
Total	8,501,256	$ 14.94	18,149,387

(1) Consists of the 2020 LTIP, 2019 LTIP, 2014 LTIP, 2009 LTIP, and the 2008 ESPP. Effective as of May 1, 2020, with the adoption of the 2020 LTIP, we ceased making new grants under the 2019 LTIP. Effective as of July 10, 2019 in connection with the adoption of the 2019 LTIP, we ceased making new grants under the 2014 LTIP. Effective as of April 30, 2014, in connection with the adoption of the 2014 LTIP, we 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) 3,155,055 shares subject to outstanding performance awards under the 2020 LTIP, inclusive of dividend reinvestments thereon (counted at a 2X multiple assuming maximum performance is achieved under the awards (representing 1,519,178 *target* awards and dividend reinvestments thereon)), (ii) 167,621 shares subject to outstanding directors' deferred stock units under the 2020 LTIP, inclusive of dividend reinvestments thereon, (iii) 2,076,527 shares subject to outstanding performance awards under the 2019 LTIP, inclusive of dividend reinvestments thereon (counted at a 1.5X multiple assuming maximum performance is achieved under the awards (representing 1,384,351 *target* awards and dividend reinvestments thereon)), (iv) 2,240,000 shares subject to outstanding stock options and stock appreciation rights under the 2019 LTIP, (v) 40,014 shares subject to outstanding directors' deferred stock units under the 2019 LTIP, inclusive of dividend reinvestments thereon, (vi) 448,331 shares subject to outstanding stock options under the 2014 LTIP, (vii) 62,117 shares subject to outstanding directors' deferred stock units under the 2014 LTIP, inclusive of dividend reinvestments thereon, (viii) 250,039 shares subject to outstanding stock options under the 2009 LTIP; and (ix) 9,034 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 3.8 years and 7.0 years, respectively, as of December 31, 2022.

(4) Consists of (i) 17,832,453 shares available for future issuance under the 2020 LTIP and (ii) 201,845 shares available for future issuance under the 2008 ESPP. As of December 31, 2022, 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 Corporation common stock fund, payable in shares of common stock, allocated to non-employee directors' accounts under the 2005 DDCP as of December 31, 2022.

(7) Consists entirely of shares available for future issuance under the 2005 DDCP as of December 31, 2022.

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 our 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 our 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 from our definitive proxy statement relating to the 2023 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2022.

Item 14. Principal Accountant Fees and Services

Information required by Item 9(e) of Schedule 14A is incorporated herein by reference from our definitive proxy statement relating to the 2023 annual meeting of shareholders, which proxy statement is expected to be filed with the SEC within 120 days after the close of our fiscal year ended December 31, 2022.

PART IV

Item 15. Exhibits and Financial Statements Schedules

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EQT CORPORATION AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
FOR THE THREE YEARS ENDED DECEMBER 31, 2022

Column A	Column B	Column C		Column D	Column E
Description	Balance at Beginning of Period	(Deductions) Additions Charged to Costs and Expenses	Additions Charged to Other Accounts	Deductions	Balance at End of Period
			(Thousands)		
Valuation allowance for deferred tax assets:					
2022	$ 550,967	$ 869	$ —	$ (186,696)	$ 365,140
2021	$ 529,992	$ 38,556	$ —	$ (17,581)	$ 550,967
2020	$ 423,444	$ 132,386	$ —	$ (25,838)	$ 529,992

See Note 9 to the Consolidated Financial Statements for a discussion of the change in valuation allowance.

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

Exhibit	Description	Method of Filing
2.01(a)**	Purchase Agreement, dated September 6, 2022, among THQ Appalachia I, LLC, THQ-XcL Holdings I, LLC, the subsidiaries of the foregoing entities named on the signature pages thereto, EQT Production Company and EQT Corporation.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on September 7, 2022.
2.01(b)**	Amended and Restated Purchase Agreement, dated December 23, 2022, among THQ Appalachia I, LLC, THQ-XcL Holdings I, LLC, the subsidiaries of the foregoing entities named on the signature pages thereto, EQT Production Company and EQT Corporation.	Incorporated herein by reference to Exhibit 2.1 to Form 8-K (#001-3551) filed on December 27, 2022.
3.01(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.
3.01(b)	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.
3.01(c)	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.
3.02	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.
4.01	Description of Capital Stock.	Incorporated herein by reference to Exhibit 4.01 to Form 10-K (#001-3551) for the year ended December 31, 2021.
4.02(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.
4.02(b)	Instrument appointing Bankers Trust Company as successor trustee to Pittsburgh National Bank.	Incorporated herein by reference to Exhibit 4.01(b) to Form 10-K (#001-3551) for the year ended December 31, 1998.
4.02(c)	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.

Exhibit	Description	Method of Filing
4.02(d)	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.
4.02(e)	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.
4.03(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.
4.03(b)	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.
4.03(c)	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.
4.04(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.
4.04(b)	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.
4.04(c)	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.
4.04(d)	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.
4.04(e)	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.
4.04(f)	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.
4.04(g)	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.
4.04(h)	Twelfth Supplemental Indenture, dated May 17, 2021, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 3.125% Senior Notes due 2026 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on May 18, 2021.
4.04(i)	Thirteenth Supplemental Indenture, dated May 17, 2021, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 3.625% Senior Notes due 2031 were issued.	Incorporated herein by reference to Exhibit 4.4 to Form 8-K (#001-3551) filed on May 18, 2021.
4.04(j)	Fourteenth Supplemental Indenture, dated October 4, 2022, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 5.678% Senior Notes due 2025 were issued.	Incorporated herein by reference to Exhibit 4.3 to Form 8-K (#001-3551) filed on October 4, 2022.
4.04(k)	Fifteenth Supplemental Indenture, dated October 4, 2022, between EQT Corporation and The Bank of New York Mellon, as trustee, pursuant to which the 5.700% Senior Notes due 2028 were issued.	Incorporated herein by reference to Exhibit 4.5 to Form 8-K (#001-3551) filed on October 4, 2022.

Exhibit	Description	Method of Filing
4.05	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.
10.01**	Third Amended and Restated Credit Agreement, dated June 28, 2022, among EQT Corporation, PNC Bank, National Association, as administrative agent, swing line lender and 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 June 28, 2022.
10.02(a)**	Credit Agreement, dated November 9, 2022, 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 November 9, 2022.
10.02(b)	First Amendment to Credit Agreement, dated December 23, 2022, 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 December 27, 2022.
10.03(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.
10.03(b)**	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.
10.03(c)**	Letter Agreement, dated November 1, 2020, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.03(c) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.03(d)**	Letter Agreement (Wherry), dated February 2, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(a) to Form 10-Q (#001-3551) for the quarter ended March 31, 2021.
10.03(e)**	Letter Agreement (Ealy), dated February 3, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(b) to Form 10-Q (#001-3551) for the quarter ended March 31, 2021.
10.03(f)**	Letter Agreement (Oxford 43), dated February 9, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, and acknowledged and agreed to by Rice Drilling D LLC and EQM Olympus Midstream, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(c) to Form 10-Q (#001-3551) for the quarter ended March 31, 2021.
10.03(g)**	Letter Agreement (JT Farms), dated February 23, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(d) to Form 10-Q (#001-3551) for the quarter ended March 31, 2021.
10.03(h)**	Letter Agreement (Ealy North – July), dated July 10, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(a) to Form 10-Q (#001-3551) for the quarter ended September 30, 2021.
10.03(i)**	Letter Agreement (Ealy North – August), dated August 25, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(b) to Form 10-Q (#001-3551) for the quarter ended September 30, 2021.

Exhibit	Description	Method of Filing
10.03(j)**	Letter Agreement (Throckmorton), dated September 13, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01(c) to Form 10-Q (#001-3551) for the quarter ended September 30, 2021.
10.03(k)**	Second Amendment to Gas Gathering and Compression Agreement, dated December 6, 2021, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.02(k) to Form 10-K (#001-3551) for the year ended December 31, 2021.
10.03(l)**	Third Amendment to Gas Gathering and Compression Agreement, dated December 21, 2021 and made effective January 1, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Incorporated herein by reference to Exhibit 10.02(l) to Form 10-K (#001-3551) for the year ended December 31, 2021.
10.03(m)**	Letter Agreement (Ealy North – February 2022), dated February 4, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended and restated.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q (#001-3551) for the quarter ended March 31, 2022.
10.03(n)**	Letter Agreement (Tesla North Well Pad), dated April 29, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended and restated.	Incorporated herein by reference to Exhibit 10.03(a) to Form 10-Q (#001-3551) for the quarter ended June 30, 2022.
10.03(o)**	Letter Agreement (King Hippo Pad Buyback Gas), dated June 10, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended and restated.	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-Q (#001-3551) for the quarter ended June 30, 2022.
10.03(p)**	Letter Agreement (Whipkey Interim Flow), dated September 19, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Incorporated herein by reference to Exhibit 10.01 to Form 10-Q (#001-3551) for the quarter ended September 30, 2022.
10.03(q)**	Letter Agreement (Carnegie North Well Pad), dated December 14, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Filed herewith as Exhibit 10.03(q).
10.03(r)**	Letter Agreement (Construction and Development), dated January 23, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Filed herewith as Exhibit 10.03(r).
10.03(s)**	Fourth Amendment to Gas Gathering and Compression Agreement, dated January 23, 2023 and made effective December 31, 2022, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering OpCo, LLC.	Filed herewith as Exhibit 10.03(s).
10.03(t)**	Letter Agreement (Franklin Denny Gas), dated January 27, 2023, among EQT Corporation, EQT Production Company, Rice Drilling B LLC, EQT Energy, LLC and EQM Gathering Opco, LLC, amending that certain Gas Gathering and Compression Agreement, dated February 26, 2020, as amended.	Filed herewith as Exhibit 10.03(t).
10.04	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.
10.05	Form of Capped Call Confirmation.	Incorporated herein by reference to Exhibit 10.2 to Form 8-K (#001-3551) filed on April 29, 2020.

Exhibit	Description	Method of Filing
10.06	Registration Rights Agreement, dated July 21, 2021, among EQT Corporation and certain security holders thereof parties thereto, and Form of Lock-Up Agreement.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on July 22, 2021.
10.07(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.
10.07(b)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (pre-2013 grants).	Incorporated herein by reference to Exhibit 10.02(b) to Form 10-K (#001-3551) for the year ended December 31, 2012.
10.07(c)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2009 Long-Term Incentive Plan (2013 and 2014 grants).	Incorporated herein by reference to Exhibit 10.02(s) to Form 10-K (#001-3551) for the year ended December 31, 2012.
10.08(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.
10.08(b)*	Form of Participant Award Agreement (Phantom Stock Unit Awards) under 2014 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.03(b) to Form 10-K (#001-3551) for the year ended December 31, 2014.
10.08(c)*	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.
10.09(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.
10.09(b)*	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.
10.09(c)*	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.
10.09(d)*	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.
10.09(e)*	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.
10.09(f)*	Form of Participant Award Agreement (Stock Option) under 2019 Long-Term Incentive Plan.	Incorporated herein by reference to Exhibit 10.06(g) to Form 10-K (#001-3551) for the year ended December 31, 2019.
10.10(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.
10.10(b)*	Amendment to EQT Corporation 2020 Long-Term Incentive Plan.	Incorporated by reference to Exhibit 99.2 to Form S-8 (#333-264423) filed on April 21, 2022.
10.11(a)*	Form of Restricted Stock Unit Award Agreement (Standard).	Incorporated herein by reference to Exhibit 10.10(a) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.11(b)*	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.
10.12*	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.
10.13(a)*	Form of Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.12(a) to Form 10-K (#001-3551) for the year ended December 31, 2020.

Exhibit	Description	Method of Filing
10.13(b)*	Form of Participant Award Agreement under Incentive Performance Share Unit Program.	Incorporated herein by reference to Exhibit 10.12(b) to Form 10-K (#001-3551) for the year ended December 31, 2020.
10.14*	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.
10.15*	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.
10.16(a)*	2005 Directors' Deferred Compensation Plan (as amended and restated December 3, 2014).	Incorporated herein by reference to Exhibit 10.09 to Form 10-K (#001-3551) for the year ended December 31, 2014.
10.16(b)*	Amendment to 2005 Directors' Deferred Compensation Plan (as amended October 2, 2018).	Incorporated herein by reference to Exhibit 10.5 to Form 10-Q (#001-3551) for the quarter ended September 30, 2018.
10.17*	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.
10.18*	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.
10.19(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.
10.19(b)*	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.
10.19(c)*	Transition Agreement and General Release, dated February 11, 2023, between EQT Corporation and David M. Khani.	Incorporated herein by reference to Exhibit 10.1 to Form 8-K (#001-3551) filed on February 13, 2023.
10.20*	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.
10.21(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.
10.21(b)*	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.
10.21(c)*	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.
10.22*	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.
21	Schedule of Subsidiaries.	Filed herewith as Exhibit 21.
23.01	Consent of Independent Registered Public Accounting Firm.	Filed herewith as Exhibit 23.01.
23.02	Consent of Netherland, Sewell & Associates, Inc.	Filed herewith as Exhibit 23.02.
31.01	Rule 13(a)-14(a) Certification of Principal Executive Officer.	Filed herewith as Exhibit 31.01.
31.02	Rule 13(a)-14(a) Certification of Principal Financial Officer.	Filed herewith as Exhibit 31.02.
32	Section 1350 Certification of Principal Executive Officer and Principal Financial Officer.	Furnished herewith as Exhibit 32.
99	Independent Petroleum Engineers' Audit Report.	Filed herewith as Exhibit 99.
101	Interactive Data File.	Filed herewith as Exhibit 101.
104	Cover Page Interactive Data File.	Formatted as Inline XBRL and contained in Exhibit 101.

*Management contract or compensatory arrangement.

**Certain schedules and similar attachments to this exhibit have been omitted pursuant to Item 601(a)(5) and/or Item 601(b)(10(iv)), as applicable, of Regulation S-K. EQT Corporation agrees to furnish an unredacted, supplemental copy (including any omitted schedule or attachment) to the SEC upon request. Redactions and omissions are designated with brackets containing asterisks.

Certain instruments evidencing long-term debt have not been filed as exhibits hereto because none of the debt authorized under any such instruments exceeds 10% of the Company's total assets. EQT Corporation agrees to furnish to the SEC, upon request, a copy of any such instruments.

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 16, 2023

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 16, 2023
/s/ DAVID M. KHANI David M. Khani (Principal Financial Officer)	Chief Financial Officer	February 16, 2023
/s/ TODD M. JAMES Todd M. James (Principal Accounting Officer)	Chief Accounting Officer	February 16, 2023
/s/ LYDIA I. BEEBE Lydia I. Beebe	Chair	February 16, 2023
/s/ LEE M. CANAAN Lee M. Canaan	Director	February 16, 2023
/s/ JANET L. CARRIG Janet L. Carrig	Director	February 16, 2023
/s/ FRANK C. HU Frank C. Hu	Director	February 16, 2023
/s/ KATHRYN J. JACKSON Kathryn J. Jackson	Director	February 16, 2023
/s/ JOHN F. MCCARTNEY John F. McCartney	Director	February 16, 2023
/s/ JAMES T. MCMANUS II James T. McManus II	Director	February 16, 2023
/s/ ANITA M. POWERS Anita M. Powers	Director	February 16, 2023
/s/ DANIEL J. RICE IV Daniel J. Rice IV	Director	February 16, 2023
/s/ HALLIE A. VANDERHIDER Hallie A. Vanderhider	Director	February 16, 2023

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