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

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2020

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ___________ to ___________

001-34778
(Commission File No.)

QEP RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware	**87-0287750**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification No.)

1050 17th Street, Suite 800, Denver, Colorado 80265
(Address of principal executive offices)
Registrant's telephone number, including area code: **303-672-6900**
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, $0.01 par value	**QEP**	**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 definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth" 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. ☒

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter (June 30, 2020): $312,599,033.

At January 31, 2021, there were 242,565,822 shares of the registrant's $0.01 par value common stock outstanding.

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Where You Can Find More Information

QEP Resources, Inc. (QEP or the Company) files annual, quarterly, and current reports with the U.S. Securities and Exchange Commission (SEC). The SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC, including QEP.

Investors can also access financial and other information via QEP's website at www.qepres.com. QEP makes available, free of charge through the website, copies of Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to such reports and all reports filed by executive officers and directors under Section 16 of the Securities Exchange Act of 1934 (the Exchange Act) reporting transactions in QEP securities. Access to these reports is provided as soon as reasonably practical after such reports are electronically filed with the SEC. Information contained on or connected to QEP's website which is not directly incorporated by reference into this Annual Report on Form 10-K should not be considered part of this report or any other filing made with the SEC.

QEP's website also can be used to access copies of charters for various board committees, including the Audit Committee, and governance documents, including QEP's Corporate Governance Guidelines and QEP's Code of Conduct. While the Company recommends that you view QEP's website, the information available on QEP's website is not part of this report and is not incorporated herein by reference.

You may request a copy of filings other than an exhibit to a filing unless that exhibit is specifically incorporated by reference into that filing, at no cost by writing or calling QEP, 1050 17th Street, Suite 800, Denver, CO 80265 (telephone number: 303-672-6900).

Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains or incorporates by reference information that includes or is based upon "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act), and Section 21E of the Exchange Act. Forward-looking statements give expectations or forecasts of future events. You can identify these statements by the fact that they do not relate strictly to historical or current facts. We use words such as "anticipate," "estimate," "expect," "project," "intend," "plan," "believe," and other words and terms of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements include statements relating to, among other things:

- focus on returns-driven growth and superior execution and strategies to achieve these objectives;
- our strategic objectives;
- effect of the novel Coronavirus disease (COVID-19) pandemic on our business results;
- the belief that the Company will be able to maintain positive cash flow and protect its balance sheet, with the ultimate goal of protecting shareholder returns over the long term;
- completion of the merger is expected to occur late in the first quarter of 2021;
- reductions in general and administrative expense to ensure our cost structure is competitive with industry peers;
- the effect of the strategic initiatives on employees and third parties;
- plans to generate Free Cash Flow and focus on capital efficiency;
- drilling and completion plans and strategies;
- adding additional acreage in our operating areas;
- estimated reserves and development of such reserves;
- adequacy of procedures implemented to protect against credit-related losses;
- expectations and assumptions regarding oil, gas and NGL prices;
- development of proved undeveloped (PUD) reserves within five years;
- reclassification of PUD reserves;
- PUD conversion rates and factors impacting conversion of PUD reserves;
- future development costs and funding sources for same;
- factors affecting our decision to modify our development plans;
- our ability to meet delivery and sales commitments;
- the effect of lost customers on the financial position or results of operations;
- FERC regulation of oil and gas pipelines;
- impact of tax legislation on our tax position and after-tax earnings or financial statements;
- adequacy of insurance;
- volatility of oil, gas and NGL prices and factors impacting such prices;
- the effects of oil, gas and NGL prices on our business;

- beliefs about the reduction of global spending on new oil and gas projects and a corresponding reduction in the global oil supply;
- expectations regarding the impact of the agreement among Organization of Petroleum Exporting Countries (OPEC) and other oil producing countries on oil prices;
- impact of shutting in wells;
- factors impacting our ability to transport oil and condensate and gas;
- credit agreement limitations that could prevent QEP from incurring certain indebtedness, which could limit QEP's ability to engage in acquisitions;
- credit agreement limitations on divestitures;
- impact of potential activist shareholders to our operations, personnel retention, strategies and costs;
- incurring penalties related to air emission noncompliance and capital expenditures to maintain or obtain operating permits and approvals;
- the underfunded status of our pension plan;
- the adjustments made to GAAP Measures to arrive at non-GAAP measures and the usefulness of non-GAAP financial measures;
- our inventory of drilling locations and the ability of that inventory to provide a solid base for generating Free Cash Flow and capital efficiency;
- evaluation of potential acquisitions, divestitures and joint venture opportunities;
- our balance sheet and sufficient liquidity providing for the ability to meet future financial obligations, ensure financial flexibility, withstand commodity price volatility, fund its development projects, operations and capital expenditures and return capital to shareholders;
- our ability to fund maturities of senior notes;
- future availability under our revolving credit facility or continued compliance with restrictive financial covenants;
- adjustments to our capital investment program based on a variety of factors, including an evaluation of drilling and completion activities and drilling results;
- focus on operating costs and per well drilling costs;
- amount and allocation of forecasted capital expenditures (excluding property acquisitions) and, plans and sources for funding operations and capital investments;
- impact of lower or higher commodity prices and interest rates;
- potential for asset impairments and factors impacting impairment amounts;
- fair value estimates and related assumptions and assessment of the sensitivity of changes in assumptions, and critical accounting estimates, including estimated asset retirement obligations;
- impact of global geopolitical and macroeconomic events and the monitoring of such events;
- plans regarding derivative contracts, including the volumes utilized, and the anticipated benefits derived there from;
- outcome and impact of various claims;
- expected cost savings and other efficiencies from multi-well pad drilling, including "tank-style" development;
- delays in completion of wells, well shut-ins and volatility to operating results caused by multi-well pad drilling;
- predictability and success of our drilling operations;
- plans and ability to pursue acquisition opportunities;
- value of pension plan assets and our plans regarding additional contributions to our pension plan;
- our plans regarding contributions to the nonqualified retirement plan (SERP), medical plan and 401(k) plan;
- the estimated actuarial loss and services cost and discount rate assumptions related to our pension plan, the SERP and medical plan, as applicable;
- estimates of the amount of additional indebtedness we may incur under our revolving credit facility;
- off-balance sheet arrangements;
- impact of inflation and price changes on our ability to raise capital, borrow money and retain personnel;
- leasehold development and financial capability to continue planned development;
- estimates of environmental remediation costs and factors impacting such estimates;
- adequacy of tax accruals and potential changes to such accruals;
- potential retirement of debt through various options, including exchanges, open market purchases, tender offers and privately negotiated transactions;
- factors impacting our ability to borrow and the interest rates offered;
- factors impacting bad debt expense;
- assumptions regarding share-based compensation;
- settlement of performance share units and restricted share units in cash;
- plans to use proceeds from any additional sales of assets to fund on-going operations, reduce debt and for general corporate purposes;
- use of net operating losses;
- alternative minimum tax credit refund amounts and timing; and

- the belief that our plan to generate Free Cash Flow on an annual basis will allow us to further strengthen our balance sheet and ultimately return capital to shareholders.

Any or all forward-looking statements may turn out to be incorrect. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Many such factors will be important in determining actual future results. These statements are based on current expectations and the current economic environment. They involve a number of risks and uncertainties that are difficult to predict. These statements are not guarantees of future performance. Actual results could differ materially from those expressed or implied in the forward-looking statements. Factors that could cause actual results to differ materially include, but are not limited to the following:

- the risk factors in Part I, Item 1A of this Annual Report on Form 10-K;
- any potential impact from the announcement that the Company has entered into a merger agreement with Diamondback Energy, Inc. and Bohemia Merger Sub, Inc.;
- changes in oil, gas and NGL prices;
- global geopolitical and macroeconomic factors;
- general economic conditions, including the performance of financial markets and interest rates;
- the length and severity of a pandemic or health crisis, such as the outbreak of COVID-19 and the measures that international, federal, state and local governments, agencies, law enforcement and/or health authorities implement to address it, which may (as with COVID-19) precipitate or exacerbate one or more of the factors herein, reduce the demand for oil, gas and NGLs and significantly disrupt or prevent us from operating our business in the ordinary course for an extended period;
- the risks and liabilities associated with acquired assets;
- asset impairments;
- liquidity constraints, including those resulting from the cost and availability of debt and equity financing;
- drilling and completion strategies, methods and results;
- assumptions around well density/spacing and recoverable reserves per well prove to be inaccurate;
- changes in estimated reserve quantities;
- changes in management's assessments as to where QEP's capital can be most profitably deployed;
- shortages and costs of oilfield equipment, services and personnel;
- changes in development plans;
- lack of available pipeline, processing and refining capacity;
- processing volumes and pipeline throughput;
- risks associated with hydraulic fracturing;
- the outcome of contingencies such as legal proceedings;
- delays in obtaining permits and governmental approvals;
- operating risks such as unexpected drilling conditions and risks inherent in the production of oil and gas;
- weather conditions;
- changes in, adoption of and compliance with laws and regulations, including decisions and policies concerning: the environment, climate change, greenhouse gas or other emissions, renewable energy mandates, natural resources, fish and wildlife, hydraulic fracturing, water use and drilling and completion techniques, as well as the risk of legal proceedings arising from such matters, whether involving public or private claimants or regulatory investigative or enforcement measures;
- derivative activities;
- potential losses or earnings reductions from our commodity price risk management programs;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications to prevent a cyberattack;
- the increased exposure to cyber and other operational risks that may result due to many of our employees working remotely for an indefinite time period due to safety concerns related to the COVID-19 pandemic;
- elimination of federal income tax deductions for oil and gas exploration and development costs;
- production, severance and property taxation rates;
- discount rates;
- regulatory approvals and compliance with contractual obligations;
- actions of, or inaction by federal, state, local or tribal governments, foreign countries and the Organization of Petroleum Exporting Countries;
- lack of, or disruptions in, adequate and reliable transportation for our production;
- competitive conditions;
- production and sales volumes;
- actions of operators on properties in which we own an interest but do not operate;

- estimates of oil and gas reserve quantities;
- reservoir performance;
- operating costs;
- inflation;
- capital costs;
- creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners and other parties;
- volatility in the securities, capital and credit markets;
- actions by credit rating agencies and their impact on the Company;
- changes in guidance issued related to tax reform legislation and the Coronavirus Aid, Relief, and Economic Security Act (CARES Act) or application of that guidance;
- changes in tax laws pertaining to independent exploration and production producers;
- actions of activist shareholders;
- any impact of the ongoing COVID-19 pandemic or any government restrictions or other responses thereto on the pending merger, including the QEP special meeting of stockholders to be held virtually on the QEP special meeting website;
- the risk that the merger agreement may be terminated in accordance with its terms and that the merger may not be completed;
- the risk that the parties may not be able to satisfy the conditions to the completion of the merger in a timely manner or at all, including the possibility that QEP stockholders do not approve the merger proposal;
- the possibility that QEP will incur significant transaction and other costs in connection with the merger, which may be in excess of those anticipated by QEP;
- the risk of any litigation relating to the merger;
- the risk related to disruption of management time from ongoing business operations due to the merger; and
- other factors, most of which are beyond the Company's control.

QEP undertakes no obligation to publicly correct or update the forward-looking statements in this Annual Report on Form 10-K, in other documents, or on the Company's website to reflect future events or circumstances. All such statements are expressly qualified by this cautionary statement.

Glossary of Terms

Adjusted EBITDA A non-GAAP financial measure which management defines as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, gains or losses from early extinguishment of debt and certain other items.

Adjusted transportation and processing costs A non-GAAP financial measure which management defines as transportation and processing costs presented on the Consolidated Statements of Operations and transportation and processing costs that are included as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. These costs are added together to reflect the total transportation and processing costs associated with QEP's production.

Argus WTI Midland An index price reflecting the weighted average price of WTI at the pipeline and storage hub at Midland, Texas.

B Billion.

bbl Barrel, which is equal to 42 U.S. gallons liquid volume and is a common measure of volume of crude oil and other liquid hydrocarbons.

basis The difference between a reference or benchmark commodity price and the corresponding sales price at various regional sales points.

basis swap A financial derivative that fixes the price difference between two sales points for a specified commodity volume over a specified time period.

Boe Barrel of oil equivalent.

Btu One British thermal unit – a measure of the amount of energy required to raise the temperature of a one-pound mass of water one degree Fahrenheit at sea level.

cf Cubic foot or cubic feet is a common unit of gas measurement. One standard cubic foot equals the volume of gas in one cubic foot measured at standard conditions – a temperature of 60 degrees Fahrenheit and a pressure of 30 inches of mercury (approximately 14.7 pounds per square inch).

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.

dry hole An exploratory, development or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

exploratory well A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

FERC The Federal Energy Regulatory Commission.

Free Cash Flow A non-GAAP financial measure which management defines as Adjusted EBITDA plus certain non-cash items that are included in Net Cash Provided by (Used in) Operating activities but excluded from Adjusted EBITDA less interest expense, excluding amortization of debt issuance costs and discounts, and accrued property, plant and equipment capital expenditures.

GAAP Accounting principles generally accepted in the United States of America.

gas All references to "gas" in this report refer to natural gas.

gross "Gross" oil and gas wells or "gross" acres are the total number of wells or acres in which the Company has an ownership interest.

IF Waha Index pricing reported in Platts' Inside FERCs' Gas Market Report, reflects the weighted average price of Natural Gas transactions at the Waha Hub in west Texas on the first day of the month.

M Thousand.

MM Million.

mineral interest The economic interest or ownership of minerals, giving the owner the right to a share of the minerals produced or proceeds from the sale of the minerals.

midstream Gas gathering, compression, treating, processing, and transmission assets and activities that are non-jurisdictional. Also includes certain crude oil, water distribution and produced water gathering and disposal systems and related commercial activities.

natural gas liquids (NGL) Liquid hydrocarbons that are extracted from the natural gas stream. NGL products include ethane, propane, butane, natural gasoline and heavier hydrocarbons.

net "Net" oil and gas wells or "net" acres are the sum of the fractional working interest the Company owns in the gross wells or acres. "Net" revenues are QEP's share of revenues from wells after deductions of royalties, overrides, net profits and other lease burdens.

NYMEX The New York Mercantile Exchange.

NYMEX CMA The New York Mercantile Exchange current month average (CMA) price of crude oil.

NYMEX HH The New York Mercantile Exchange price of natural gas at the Henry Hub.

NYMEX WTI The New York Mercantile Exchange price of West Texas Intermediate crude oil.

oil All references to "oil" in this report refer to crude oil and condensate.

oil equivalent Natural gas is converted to a crude oil equivalent at the ratio of six Mcf of natural gas to one barrel of crude oil equivalent.

possible reserves Those additional reserves that are less certain to be recovered than probable reserves.

probable reserves Those additional reserves that are less certain to be recovered than proved reserves but, together with proved reserves, are as likely as not to be recovered.

proved developed reserves Reserves that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

proved properties Properties with proved reserves.

proved reserves Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

proved undeveloped reserves or PUD reserves Proved undeveloped reserves or PUD reserves are those reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

PUD reserves conversion rate The volume of PUD reserves transferred to proved developed over total volume of PUD reserves as of the prior year end.

reserves Estimated remaining quantities of crude oil, natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production.

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

resource play Refers to regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in areal extent. Resource plays are characterized by continuous, aerially extensive hydrocarbon accumulations in tight sand, shale and coal reservoirs.

royalty An interest in an oil and gas lease that gives the mineral owner the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling, completing or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the minerals at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

seismic data An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape and depth of a subsurface rock formation. 2-D seismic provides two-dimensional information and 3-D seismic provides three-dimensional views.

undeveloped reserves Reserves of any category that are expected to be recovered from new wells or from existing wells where a relatively major expenditure is required for recompletion.

working interest An interest in an oil and gas lease that gives the owner the right to drill, produce and conduct operating activities on the leased acreage and receive a share of any production, subject to all royalties, other burdens and to all capital costs and operating expenses.

FORM 10-K
ANNUAL REPORT 2020
PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Nature of Business

QEP Resources, Inc. (QEP or the Company) is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its wholly-owned subsidiaries on a consolidated basis. QEP was incorporated on May 18, 2010, in the State of Delaware. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

The following information provides material updates to the development of QEP's business disclosed in its 2019 Annual Report on Form 10-K. Refer to Item 1 of Part I of QEP's 2019 Annual Report on Form 10-K for additional discussion on the developments to QEP's business prior to the year ended December 31, 2020.

Merger

On December 20, 2020, the Company entered into an Agreement and Plan of Merger (Merger Agreement) with Diamondback Energy, Inc. (Diamondback) and Bohemia Merger Sub, Inc., a wholly owned subsidiary of Diamondback (Merger Sub), which provides that, among other things, and subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into QEP, with QEP surviving as a direct, wholly owned subsidiary of Diamondback (Merger). Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of the Company (other than any Excluded Shares, any Converted Shares and Company Restricted Stock Awards (each as defined in the Merger Agreement)) will be converted into the right to receive 0.05 shares of common stock, par value $0.01 per share, of Diamondback (Merger Consideration). The Merger Agreement also addresses the treatment of QEP equity awards in the Merger. Diamondback's common stock is listed and traded on the NASDAQ Global Select Market under the symbol "FANG". The transaction was unanimously approved by the Boards of Directors of both companies. The Merger is expected to close late in the first quarter of 2021, and is subject to the approval of the Company's stockholders and other customary closing conditions. During the year ended December 31, 2020, the Company incurred $4.5 million of merger costs recognized in "General and administrative" expense on the Consolidated Statements of Operations and $5.0 million of additional merger costs were recognized in "Prepaid expenses" on the Consolidated Balance Sheets as of December 31, 2020.

For additional information regarding the Merger and QEP's Board's process and rationale for the Merger, please see the proxy statement and other documents filed with the SEC as they become available.

Strategies

We are focused on creating value for our shareholders through returns-focused operations and superior execution. To achieve these objectives we strive to:

- operate in a safe and environmentally responsible manner;
- allocate capital to those projects that generate the highest returns;
- reduce leverage and strengthen the balance sheet;
- generate Free Cash Flow;
- maintain an inventory of high return oil weighted development projects in our operating areas;
- build contiguous acreage positions that drive operating efficiencies;
- acquire businesses and assets that complement or expand our current business;
- be the operator of our assets, whenever possible;
- be the low-cost driller and producer in the basins where we operate, as compared to our peers;
- actively market our oil production to maximize value and flow assurance;
- utilize derivative contracts to reduce the impact of oil, gas and NGL price volatility;
- attract and retain the best people; and
- maintain a capital structure that provides sufficient financial flexibility to successfully operate and grow the business.

Overview

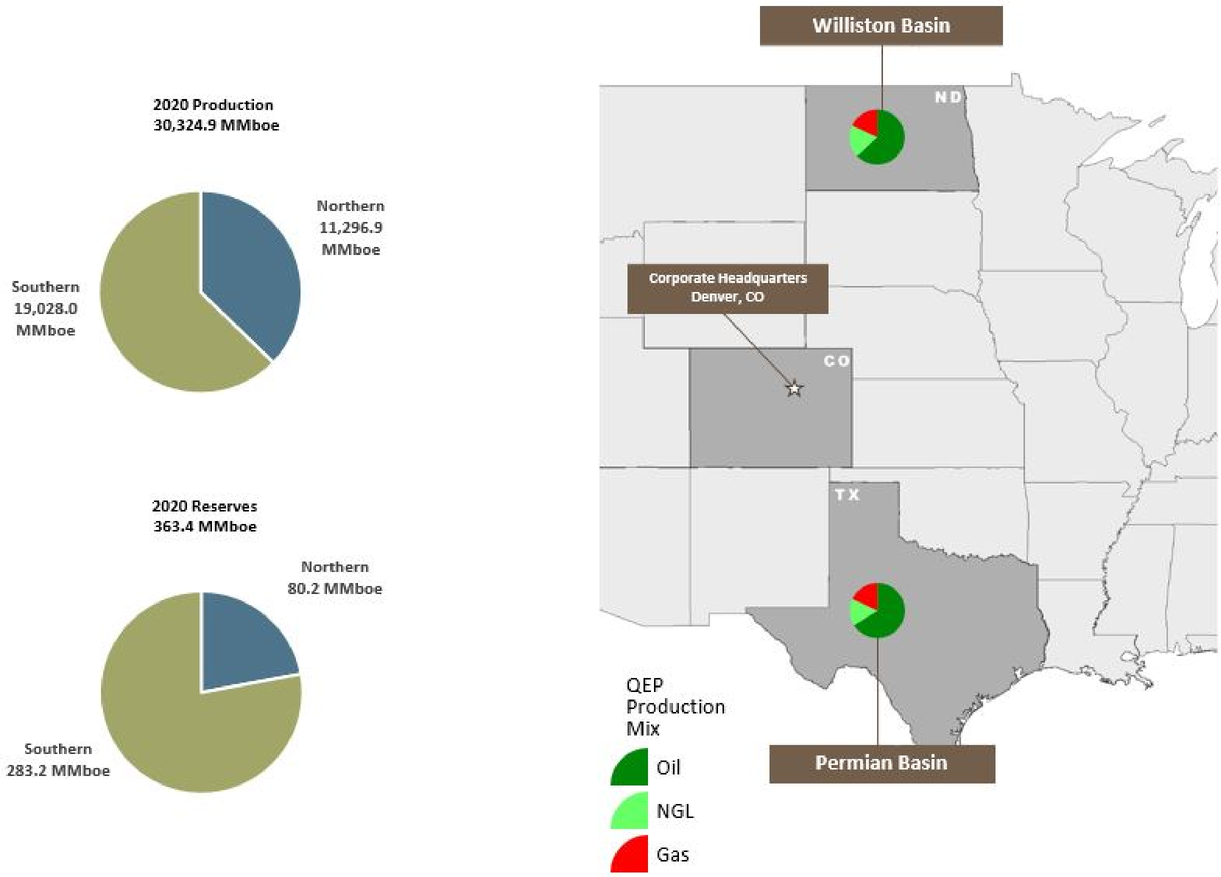
QEP conducts exploration and production (E&P) activities in two of North America's most productive hydrocarbon resource plays. For the year ended December 31, 2020, the Company reported production of over 30 MMboe, owned interests in over 167,000 gross acres, drilled 72 gross operated and non-operated productive wells and had an extensive inventory of identifiable undeveloped drilling locations between the Permian and Williston basins.

As a result of the reduction of the Company's operational footprint over the past few years, QEP reassessed its organizational needs and significantly reduced its general and administrative expense to ensure its cost structure is competitive with industry peers.

In conjunction with the implementation of the Company's strategic initiatives, QEP incurred costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 3 – Acquisitions and Divestitures and Note 8 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

The Company continues to focus on reducing its operating costs, per well drilling costs, general and administrative costs and managing its liquidity. We believe our plan to generate Free Cash Flow on an annual basis will allow us to further strengthen our balance sheet and ultimately return capital to shareholders.

The following map illustrates the location of substantially all of the Company's operating activities, the location of its Northern and Southern Regions, and related reserve and production data as of and during the year ended December 31, 2020:



QEP sells oil and condensate and NGL volumes to refiners, marketers, midstream service providers and other companies. QEP sells gas volumes to wholesale marketers, industrial users, local distribution companies, midstream service providers and utility companies. The Company regularly evaluates counterparty credit risk and may require parental guarantees, letters of credit or prepayment from companies with perceived higher credit risk. In order to get its oil and condensate, gas and NGL volumes to their ultimate sale point, QEP has contracts with midstream providers for the gathering, transportation, processing and/or fractionation of these products. Disruptions impacting pipelines or other midstream provider facilities can impact QEP's production volumes. In cases where QEP's wells are not connected to sales pipelines, the Company sells its products to buyers at the well and the buyer arranges transportation to the ultimate destination.

Description of Properties

<u>Southern Region</u>

Permian Basin

QEP has 788.3 net productive wells, including its interest in non-operating wells, in the Permian Basin. QEP has multiple targeted formations within its acreage in the Permian Basin and is actively developing oil producing zones, primarily in the Spraberry Shale and Wolfcamp formations. The Company utilizes a "tank-style" completion methodology and continues to test additional formations and evaluate the appropriate density of its development program. During the year ended December 31, 2020, the Company put 50 gross operated wells on production. As of December 31, 2020, QEP had two company-operated rigs drilling in the Permian Basin. QEP has built water infrastructure and centralized gathering infrastructure in the Permian Basin to support its tank-style development.

Other Southern
The remainder of QEP's Southern Region primarily consists of small royalty interests over a few properties.

Northern Region

Williston Basin
QEP has 366.4 net productive wells, including its interests in non-operated wells, in the Williston Basin. During the year ended December 31, 2020, the Company put two gross operated wells on production.

Other Northern
The remainder of QEP's Northern Region leasehold interests and proved reserves are distributed over a number of fields and properties in various states.

Reserves

At December 31, 2020 and 2019, QEP's estimated proved reserves were approximately 363.4 MMboe and 382.3 MMboe, respectively, of which 98% were Company operated in both years. Proved developed reserves represented 45% and 50% of the Company's total proved reserves at December 31, 2020 and 2019, respectively, while the remaining reserves were classified as proved undeveloped. All reported reserves are located in the United States. QEP's estimated proved reserves are summarized in the table below:

	December 31, 2020				December 31, 2019			
	Oil and condensate (MMbbl)	**Gas[1] (Bcf)**	**NGL (MMbbl)**	**Total[1] (MMboe)[2]**	Oil and condensate (MMbbl)	Gas[1] (Bcf)	NGL (MMbbl)	Total[1] (MMboe)[2]
Proved developed reserves	**101.2**	**185.0**	**32.0**	**164.0**	117.5	217.0	36.7	190.4
Proved undeveloped reserves	**136.7**	**183.3**	**32.1**	**199.4**	137.4	156.3	28.5	191.9
Total proved reserves	**237.9**	**368.3**	**64.1**	**363.4**	254.9	373.3	65.2	382.3

(1) Generally, gas consumed in operations was excluded from reserves, however, in some cases; produced gas consumed in operations was included in reserves when the volumes replaced fuel purchases.
(2) Natural gas is converted to a crude oil equivalent at the ratio of six Mcf of natural gas to one barrel of crude oil equivalent.

QEP's reserve, production and reserve life index for each of the years ended December 31, 2018 through December 31, 2020 are summarized in the table below:

Year Ended December 31,	Year End Reserves (MMboe)	Oil and condensate, Gas and NGL Production[2][3] (MMboe)	Reserve Life Index[1][2][3] (Years)
2018	658.2	49.6	13.3
2019	382.3	31.9	12.0
2020	**363.4**	**30.3**	**12.0**

(1) Reserve life index is calculated by dividing year-end proved reserves by production for that year.
(2) The reserve life index for 2019 excludes 0.3 MMboe of production volumes from Haynesville/Cotton Valley due to the divestiture of the Haynesville/Cotton Valley assets in January, 2019. Including production volumes from the divested Haynesville/Cotton Valley assets, the reserve life index is 11.9 years for the year ended December 31, 2019.
(3) The reserve life index for 2018 excludes 2.2 MMboe of production volumes from the Uinta Basin due to the divestiture of the Uinta Basin assets in September 2018. Including production volumes from the divested Uinta Basin assets, the reserve life index is 12.7 years for the year ended December 31, 2018.

Proved Reserves

Estimates of proved reserves and related information are presented in accordance with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules permit the use of reliable technologies to estimate and categorize reserves and require the use of the unweighted average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for the prior 12 months (unless contractual arrangements designate the price) to calculate economic producibility of reserves and the discounted cash flows reported as the Standardized Measure of Future Net Cash Flows Relating to Proved Reserves. Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding estimates of proved reserves and the preparation of such estimates.

QEP's proved reserves in its major operating areas are summarized in the table below:

	December 31,			
	2020		2019	
Northern Region	(MMboe)	(% of total)	(MMboe)	(% of total)
Williston Basin	**80.2**	**22 %**	116.0	30 %
Other Northern	**—**	**— %**	—	— %
Southern Region				
Permian Basin	**283.2**	**78 %**	266.3	70 %
Other Southern	**—**	**— %**	—	— %
Total proved reserves	**363.4**	**100 %**	382.3	100 %

QEP's total proved reserves as of December 31, 2020, decreased 18.9 MMboe from December 31, 2019, primarily due to lower commodity prices and production in 2020, partially offset by changes in capital development plans and sequence to continue to focus on Free Cash Flow generation.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2020 are summarized in the table below:

	2020
	(MMboe)
Proved undeveloped reserves at January 1,	191.9
Transferred to proved developed reserves	**(30.1)**
Revisions to previous estimates	**37.6**
Proved undeveloped reserves at December 31,	**199.4**

Transfers to proved developed reserves. The costs incurred for the development of PUD reserves were approximately $222.3 million, $426.1 million and $606.5 million for the years ended December 31, 2020, 2019 and 2018, respectively.

QEP's planned and actual transfers of proved undeveloped reserves to proved developed reserves results for the year ended December 31, 2020 are summarized in the table below:

	Planned Transfers to Proved Developed Reserves in 2020 as of December 31, 2019 (PUD conversions)	Actual Transfers to Proved Developed Reserves in 2020 (PUD conversions)	Difference
		(MMboe)	
Northern Region			
Williston Basin	8.5	0.6	(7.9)
Other Northern	—	—	—
Southern Region			
Permian Basin	29.5	29.5	—
Other Southern	—	—	—
Total	38.0	30.1	(7.9)

QEP transferred 30.1 MMboe of PUD reserves to proved developed reserves in 2020 compared to 38.0 MMboe that were planned for 2020. QEP's PUD reserve conversion rate (the percentage of booked PUD reserves) was 16%, 10% and 12% for the years ended December 31, 2020, 2019 and 2018, respectively. At December 31, 2019, QEP's planned PUD reserve conversion rate for 2020 was 20%. QEP converted 18% and 2%, respectively, of the Permian and Williston basin PUD reserves in 2020. QEP converted fewer PUD reserves than expected in the Williston Basin, primarily due to the Company's decision to reduce completion activity and suspend the refracturing program in the Williston Basin during 2020 in light of market conditions.

All of QEP's proved undeveloped reserves at December 31, 2020 are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. In accordance with the SEC rules, QEP removes reserves associated with a PUD location from reported proved reserves if such location is scheduled, under the then-current development plan, to be drilled later than five years from the date that such location was first reported as PUD. QEP's five-year development plan generally does not contemplate a uniform (i.e. 20% per year) conversion of PUD reserves in all of its producing regions, and PUD reserve conversion rates will likely differ by producing region.

At December 31, 2020, QEP estimates that its future development costs relating to the development of PUD reserves are approximately $202.6 million in 2021, $289.1 million in 2022 and $365.8 million in 2023. QEP believes cash flow from operations and availability under its revolving credit facility will be sufficient to cover these estimated future development costs.

Revisions to previous estimates. Revisions to previous estimates reflect our ongoing evaluation of our asset portfolio. In 2020, our PUD reserves increased by 37.6 MMboe due to the factors summarized in the table below:

	2020
	(MMboe)
Revisions due to:	
Changes in year-end prices (price impact to January 1, 2019 balance)	**(2.6)**
Positive performance	**1.9**
Change in development plans	**58.8**
Removal due to five year SEC rule	**(16.9)**
Other	**(3.6)**
Total revisions to prior estimates	**37.6**

In 2020, PUD reserves were revised upward by 37.6 MMboe. The increase was primarily due to our continued corporate strategy of generating Free Cash Flow through capital efficiency. This corporate strategy resulted in the addition of 58.8 MMboe of PUD reserves due to the change in the development sequence in the Permian Basin. This addition was partially offset by the removal of 16.9 MMboe of PUD reserves which will no longer be developed within five years of the initial date of booking the reserves due to the reduction in the capital program over the next five years, primarily in the Permian Basin.

Additional Disclosures
Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K for more information pertaining to QEP's proved reserves as of the end of each of the last three years.

In addition to this filing, QEP will file reserve estimates as of December 31, 2020, with the Energy Information Administration of the Department of Energy (EIA) on Form EIA-23. Although QEP uses the same technical and economic assumptions when it prepares the Form EIA-23 as used to estimate reserves for this Annual Report on Form 10-K, it is obligated to report to the EIA reserves only for wells it operates, not for all of the wells in which it has an interest, and to include the reserves attributable to other owners in such wells.

Third Party Reserve Reports
The Company retained Ryder Scott Company, L.P. (RSC), independent oil and gas reserve evaluation engineering consultants, to prepare the estimates of all of its proved reserves as of December 31, 2020, 2019 and 2018.

Qualifications of Technical Person Preparing Reserve Reports
The individual at RSC who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2020, is a registered Professional Engineer in the States of Colorado and Texas and graduated with a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001. The individual has over 10 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. A more detailed letter, including such individual's professional qualifications, has been filed as part of Exhibit 99.1 to this report.

The individual at QEP responsible for ensuring the accuracy of the reserve estimate preparation material provided to RSC and reviewing the estimates of reserves received from RSC is QEP's Corporate Reserves Manager. This individual is a Licensed Professional Engineer in the State of Texas and graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University. This individual has over 34 years of experience in the petroleum industry, including 17 years of experience in corporate reserves management.

Technologies Used
To estimate proved reserves, the SEC allows a company to use technologies that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. A variety of methodologies were used to determine QEP's proved reserve estimates. The principal methodologies employed are performance, analogy and volumetric methods.

All of the proved producing reserves as of December 31, 2020, attributable to producing wells and/or reservoirs were estimated by performance methods. Volumetric measures are then used, when available, to further corroborate these reserve estimates. Performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production data available through late 2020, in those cases where such data were considered to be definitive. For wells currently producing, forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

All of QEP's proved developed non-producing and undeveloped reserves as of December 31, 2020 were estimated by analogy to offset producing wells. Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by QEP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in these estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies. The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, market demand and/or allowables or other constraints set by regulatory bodies. Some combination of these methods is used to determine reserve estimates in substantially all of QEP's fields.

Internal Controls Over Proved Reserve Estimates
At the end of each year, management develops a five-year capital expenditure plan based on QEP's best available data at the time the plan is developed. The Company's capital expenditure plan includes a development plan for converting PUD reserves. The development plan includes only PUD reserves that the Company is reasonably certain will be drilled within five years of booking based upon management's evaluation of a number of qualitative and quantitative factors, including estimated risk-based returns; estimated future location density; current commodity pricing and cost forecasts consistent with SEC guidelines; recent drilling and re-stimulated well results; availability of services, equipment, supplies and personnel; seasonal weather; and changes in drilling and completion techniques and technology. This process is intended to ensure that PUD reserves are only claimed for locations where a final investment decision has been made by the Company.

QEP maintains a Reserves Review Committee comprised of members of QEP's management team and the Company's Corporate Reserves Manager. The Reserves Review Committee meets on a semi-annual basis, including prior to the filing of reserve estimates with the SEC and any public disclosure of reserve estimates. The Reserves Review Committee reviews data that is submitted by the Corporate Reserves Manager to RSC, including cost and pricing assumptions and reserve reconciliations from the previous reserve determinations. The Corporate Reserves Manager's Annual Reserve Summary Report and the Reserve Committee's Certification are provided to the Audit Committee annually. The Audit Committee also meets annually with RSC to review the reserves estimation reporting process and disclosures. QEP's Board annually reviews the Company's five-year capital expenditure plan and approves the capital budget for the first year of the development plan.

Management reviews and revises the development plan throughout the year and may modify the development plan after evaluating a number of factors, including operating and drilling results; current and expected future commodity prices; estimated risk-based returns; estimated well density; advances in technology; cost and availability of services, equipment, supplies and personnel; acquisition and divestiture activity; and our current and projected financial condition and liquidity. Management reviews changes to the development plan with the Audit Committee and the Board quarterly. Changes in the development plan are also considered by management, the Corporate Reserves Manager and the Reserves Review Committee when reserves are estimated at year-end. If changes result in certain PUD reserves no longer being scheduled for development within five years from the date of initial booking, QEP reclassifies those PUD reserves to non-proved reserve categories. In addition, PUD locations and reserves may be removed from the development plan ahead of their five-year life expiration as a result of asset divestitures and acquisitions and associated changes in the priority of development within QEP's portfolio of assets.

Production, Prices and Production Costs

The following table sets forth the production volumes and field-level prices of oil and condensate, gas and NGL produced, and the related production costs, for the years ended December 31, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018
Production volumes			
Oil and condensate (Mbbl)	**19,721.6**	21,558.3	23,932.0
Gas (Bcf)	**32.5**	33.1	139.6
NGL (Mbbl)	**5,185.1**	5,139.0	4,661.4
Total equivalent production (Mboe)	**30,324.9**	32,210.3	51,857.9
Average field-level price [(1)]			
Oil (per bbl)	**$ 35.08**	$ 52.54	$ 59.43
Gas (per Mcf)	**$ 1.22**	$ 1.58	$ 2.82
NGL (per bbl)	**$ 8.82**	$ 11.15	$ 23.79
Production costs (per Boe)			
Lease operating expense	**$ 4.67**	$ 5.68	$ 5.07
Adjusted transportation and processing costs[(2)]	**3.85**	3.22	3.33
Production and property taxes	**1.91**	2.98	2.52
Total production costs	**$ 10.43**	$ 11.88	$ 10.92

(1) The average field-level price does not include the impact of settled commodity price derivatives or transportation and processing costs reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations.

(2) Adjusted transportation and processing costs (a non-GAAP measure) includes transportation and processing costs that are reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Management adds these costs together with transportation and processing costs reflected on the Consolidated Statements of Operations to reflect the total operating costs associated with its production. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total production costs required to operate the wells for the period. This non-GAAP measure should be considered by the reader in addition to but not instead of, the financial statements prepared in accordance with GAAP. Refer to Operating Expenses and Note 2 – Revenue in Items 7 and 8, respectively, of Part II of this Annual Report on Form 10-K for more information.

A summary of oil and condensate production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
Oil and condensate production volumes (Mbbl)					
Northern Region					
Williston Basin	**7,137.2**	7,992.8	11,229.5	**(855.6)**	(3,236.7)
Uinta Basin	**—**	—	447.3	**—**	(447.3)
Other Northern	**(0.4)**	40.9	93.2	**(41.3)**	(52.3)
Southern Region					
Permian Basin	**12,584.5**	13,522.6	12,137.4	**(938.1)**	1,385.2
Haynesville/Cotton Valley	**—**	(0.4)	15.6	**0.4**	(16.0)
Other Southern	**0.3**	2.4	9.0	**(2.1)**	(6.6)
Total production	**19,721.6**	21,558.3	23,932.0	**(1,836.7)**	(2,373.7)

A summary of gas production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
Gas production volumes (Bcf)					
Northern Region					
Williston Basin	**12.0**	14.0	15.6	**(2.0)**	(1.6)
Uinta Basin	**—**	—	10.2	**—**	(10.2)
Other Northern	**0.1**	0.2	0.9	**(0.1)**	(0.7)
Southern Region					
Permian Basin	**20.4**	16.9	10.6	**3.5**	6.3
Haynesville/Cotton Valley	**—**	1.9	102.2	**(1.9)**	(100.3)
Other Southern	**—**	0.1	0.1	**(0.1)**	—
Total production	**32.5**	33.1	139.6	**(0.6)**	(106.5)

A summary of NGL production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
NGL production volumes (Mbbl)					
Northern Region					
Williston Basin	**2,143.8**	2,073.2	2,495.3	**70.6**	(422.1)
Uinta Basin	**—**	—	99.3	**—**	(99.3)
Other Northern	**1.5**	1.8	10.5	**(0.3)**	(8.7)
Southern Region					
Permian Basin	**3,039.5**	3,062.7	2,054.4	**(23.2)**	1,008.3
Haynesville/Cotton Valley	**—**	—	0.5	**—**	(0.5)
Other Southern	**0.3**	1.3	1.4	**(1.0)**	(0.1)
Total production	**5,185.1**	5,139.0	4,661.4	**46.1**	477.6

A summary of total oil equivalent production by major geographical area is shown in the following table:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
Total production volumes (Mboe)					
Northern Region					
Williston Basin	**11,284.9**	12,403.8	16,331.3	**(1,118.9)**	(3,927.5)
Uinta Basin	**—**	—	2,243.5	**—**	(2,243.5)
Other Northern	**12.0**	71.6	247.1	**(59.6)**	(175.5)
Southern Region					
Permian Basin	**19,023.8**	19,406.6	15,960.3	**(382.8)**	3,446.3
Haynesville/Cotton Valley	**—**	310.5	17,050.5	**(310.5)**	(16,740.0)
Other Southern	**4.2**	17.8	25.2	**(13.6)**	(7.4)
Total production	**30,324.9**	32,210.3	51,857.9	**(1,885.4)**	(19,647.6)

A regional comparison of average field-level prices (excluding the impact of settled commodity price derivatives or transportation and processing costs reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations) and average production costs (excluding production and property taxes) per Boe is shown in the following table:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
Average field-level oil price (per bbl)					
Northern Region	**$ 35.04**	$ 52.52	$ 62.63	**$ (17.48)**	$ (10.11)
Southern Region	**$ 35.10**	$ 52.55	$ 56.34	**$ (17.45)**	$ (3.79)
Average field-level oil price	**$ 35.08**	$ 52.54	$ 59.43	**$ (17.46)**	$ (6.89)
Average field-level gas price (per Mcf)					
Northern Region	**$ 1.59**	$ 2.36	$ 2.71	**$ (0.77)**	$ (0.35)
Southern Region	**$ 1.00**	$ 1.00	$ 2.84	**$ —**	$ (1.84)
Average field-level gas price	**$ 1.22**	$ 1.58	$ 2.82	**$ (0.36)**	$ (1.24)
Average field-level NGL price (per bbl)					
Northern Region	**$ 6.70**	$ 9.37	$ 23.56	**$ (2.67)**	$ (14.19)
Southern Region	**$ 10.31**	$ 12.36	$ 24.09	**$ (2.05)**	$ (11.73)
Average field-level NGL price	**$ 8.82**	$ 11.15	$ 23.79	**$ (2.33)**	$ (12.64)
Lease operating and adjusted transportation and processing costs (per Boe)					
Northern Region	**$ 12.99**	$ 13.70	$ 12.90	**$ (0.71)**	$ 0.80
Southern Region	**$ 7.95**	$ 7.55	$ 5.82	**$ 0.40**	$ 1.73
Adjusted average lease operating and transportation and processing costs	**$ 8.52**	$ 8.90	$ 8.40	**$ (0.38)**	$ 0.50

Northern Region

Williston Basin

Production volumes decreased 9% to 11,284.9 Mboe during 2020 compared to 2019, primarily as a result of the reduction in operated completion activity and suspension of the refracturing program beginning in the second quarter of 2020 through the end of the year in order to proactively manage Free Cash Flow and preserve liquidity as a result of the COVID-19 pandemic and challenging market conditions. The decrease in production volumes was partially offset by increased non-operated activity during the fourth quarter of 2020.

Production volumes decreased 24% to 12,403.8 Mboe during 2019 compared to 2018, primarily as a result of reduced capital expenditures in 2019 in order to focus on generating Free Cash Flow and natural production decline, partially offset by seven new operated well completions and two refractured operated wells, which were put on production in the fourth quarter of 2019.

During the years ended December 31, 2020, 2019 and 2018, Williston Basin production represented 37%, 39% and 31%, respectively, of QEP's total equivalent production.

Uinta Basin

Due to the divestiture of the Uinta Basin properties in September 2018, there was no production during the years ended December 31, 2020 and 2019.

During the year ended December 31, 2018, Uinta Basin production represented 4% of QEP's total equivalent production.

Other Northern

Production volumes decreased 83% and 71% during the years ended December 31, 2020 and 2019, respectively, primarily due to the continued divestiture of properties during 2020 and 2019.

During the years ended December 31, 2020, 2019 and 2018, Other Northern production represented less than 1% of QEP's total equivalent production.

Southern Region

Permian Basin

Production volumes decreased 2% to 19,023.8 Mboe during 2020 compared to 2019, primarily as a result of the suspension of completion operations in the Permian Basin beginning in March 2020 until the fourth quarter of 2020 in order to proactively manage Free Cash Flow and preserve liquidity as a result of the COVID-19 pandemic and challenging market conditions. This was partially offset by 50 new operated well completions that were put on production during the year ended December 31, 2020.

Production volumes increased 22% to 19,406.6 Mboe during 2019 compared to 2018, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations.

During the years ended December 31, 2020, 2019 and 2018, Permian Basin production represented 63%, 60%, and 31% respectively, of QEP's total equivalent production.

Haynesville/Cotton Valley

Due to the divestiture of the Haynesville/Cotton Valley properties in January 2019, there was no production during the year ended December 31, 2020.

Production volumes decreased 98% to 310.5 Mboe during 2019 compared to 2018, due to the divestiture of the Haynesville/Cotton Valley properties in January 2019.

During the years ended December 31, 2019 and 2018, Haynesville/Cotton Valley's production represented 1% and 34%, respectively, of QEP's total equivalent production.

Other Southern

Production volumes decreased 76% and 29% during the years ended December 31, 2020 and 2019, respectively, due to the continued divestiture of properties.

During the years ended December 31, 2020, 2019 and 2018, Other Southern production represented less than 1% of QEP's total equivalent production.

Productive Wells

The following table summarizes the Company's operated and non-operated productive wells as of December 31, 2020, all of which are located in the U.S.:

	Oil[1]	
	Gross	Net
Northern Region		
Williston Basin	740	366.4
Other Northern	—	—
Southern Region		
Permian Basin	833	788.3
Other Southern	—	—
Total productive wells	1,573	1,154.7

(1) These totals represent productive wells as of December 31, 2020, primarily in our core operating areas of the Williston and Permian basins. In addition to the table above, QEP has interests, primarily overriding royalty interests, in a number of wells outside of our core areas that have minimal revenues and reserves.

Although many wells produce both oil and gas, and many gas wells also have allocated NGL volumes from gas processing, a well is categorized as either an oil well or a gas well based upon the ratio of oil to gas produced at the wellhead. As of December 31, 2020, the Company only had oil wells. Additionally, each well completed in more than one producing zone is counted as a single well.

Acreage

The following table summarizes developed and undeveloped acreage in which the Company owns a working interest or a mineral interest as of December 31, 2020. "Undeveloped Acreage" includes leasehold interests that may already have been classified as containing proved undeveloped reserves and unleased mineral interest acreage owned by the Company. Excluded from the table is acreage in which the Company's interest is limited to royalty, overriding royalty or other similar interests. All leasehold acres are located in the U.S.

	Developed Acres[1]		Undeveloped Acres[2]		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
North Dakota	80,572	64,030	31,897	30,580	112,469	94,610
Texas	34,552	34,240	16,172	14,822	50,724	49,062
Other	4,065	2,126	—	—	4,065	2,126
Total	119,189	100,396	48,069	45,402	167,258	145,798

(1) Developed acreage is leased acreage or mineral interests assigned to productive wells.

(2) Undeveloped acreage is leased acreage and mineral interests on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved reserves.

Expiring Leaseholds

The majority of our leasehold acreage is held by production. The Company also has drilling and development agreements with third parties that require drilling obligations be met within the lease term in order to retain leasehold acreage. A portion of the leases covering the acreage summarized in the preceding table will expire at the end of their respective primary lease terms unless the leases are renewed, extended or drilling or production has occurred on the acreage subject to the lease prior to that date. Leases held by production generally remain in effect until production ceases. The following table sets forth the gross and net undeveloped acres subject to leases summarized in the preceding table that will expire during the periods indicated:

	Undeveloped Acres Expiring	
	Gross	Net
Year ending December 31,		
2021	800	347
2022	—	—
2023	480	70
2024	—	—
2025 and later	—	—
Total	1,280	417

Drilling Completion and Production Activities

The following table summarizes the total number of development and exploratory wells drilled (defined to include the number of wells completed at any time during the applicable year, regardless of when drilling was initiated), including both operated and non-operated wells, during the years indicated.

	Development Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2020								
Northern Region								
Williston Basin	**18**	**4.8**	**—**	**—**	**—**	**—**	**—**	**—**
Other Northern	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Southern Region								
Permian Basin	**54**	**48.8**	**—**	**—**	**—**	**—**	**—**	**—**
Other Southern	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total	**72**	**53.6**	**—**	**—**	**—**	**—**	**—**	**—**
Year Ended December 31, 2019								
Northern Region								
Williston Basin	26	8.4	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	64	59.3	—	—	—	—	—	—
Haynesville/Cotton Valley	—	—	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	90	67.7	—	—	—	—	—	—
Year Ended December 31, 2018								
Northern Region								
Williston Basin	24	10.3	—	—	—	—	—	—
Uinta Basin	2	2.0	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	106	105.2	—	—	—	—	—	—
Haynesville/Cotton Valley	16	4.6	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	148	122.1	—	—	—	—	—	—

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion as of December 31, 2020:

		Operated				Non-operated			
	Drilling	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Rigs	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region									
Williston Basin	—	—	—	4	2.9	—	—	10	0.1
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin[(1)]	2	8	7.0	48	41.8	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—	—

(1) The number of gross operated drilling wells in the Permian Basin includes 6 wells for which surface casing has been set as of December 31, 2020.

Each gross well completed in more than one producing zone is counted as a single well. Delays and well shut-ins resulting from multi-well pad drilling have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells could impact planned conversion of PUD reserves to proved developed reserves.

The following table presents the number of operated wells in the process of being drilled or waiting on completion at December 31, 2020:

	Permian Basin		Williston Basin	
	December 31, 2020			
	Gross	Net	Gross	Net
Well Progress				
Drilling	8	7.0	—	—
Waiting to be completed	42	36.6	4	2.9
Completed, awaiting production	6	5.2	—	—
Waiting on completion	48	41.8	4	2.9

The following table presents the number of operated and non-operated wells completed and turned to sales (put on production) for the year ended December 31, 2020:

	Operated Put on Production		Non-operated Put on Production	
	Year Ended December 31, 2020			
	Gross	Net	Gross	Net
Northern Region				
Williston Basin	2	1.5	16	3.3
Other Northern	—	—	—	—
Southern Region				
Permian Basin	50	48.4	4	0.4
Other Southern	—	—	—	—

Delivery Commitments

QEP is a party to various long-term agreements that require us to physically deliver oil and condensate and gas with future firm delivery commitments as follows:

Period	Delivery Commitments (MMboe)[1]
2021	19.8
Thereafter	32.6

[1] Includes delivery commitments related to future obligations in an area in which the Company no longer has production operations. During the year ended December 31, 2019, the Company recognized $7.7 million of firm transportation expense related to the future obligations in this area.

These commitments are physical delivery obligations with prices based on prevailing index prices for oil and condensate and gas at the time of delivery or contracted gathering arrangements that require delivery of a fixed and determinable quantity of oil and condensate or gas in the future. None of these commitments require the Company to deliver oil and condensate or gas produced specifically from any of the Company's properties. The Company believes that its production and reserves should be adequate to meet its term sales commitments or that it can purchase sufficient volumes of oil and condensate or gas in the market at index-related prices to satisfy its sales commitments. The Company has incurred shortfalls related to some of its gathering and firm transportation commitments and as a result paid contractual obligations of $8.9 million, $8.3 million and $13.4 million for the years ended December 31, 2020, 2019 and 2018, respectively, for deficiencies associated with gathering and firm physical delivery obligations. See also Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Contractual Obligations, in this Annual Report on Form 10-K for discussion of firm transportation commitments related to oil and condensate and gas deliveries.

In addition, at December 31, 2020, the Company did not have a significant amount of production from QEP's owned properties that was subject to priorities or curtailments that may affect quantities delivered to its customers, priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond the Company's control that may affect its ability to meet its contractual obligations other than those discussed in Part I, Item 1A – Risk Factors, in this Annual Report on Form 10-K.

Seasonality

QEP drills and completes wells throughout the year, but adverse weather conditions can impact drilling, completion and field operations, which can impact overall production volumes. Seasonal anomalies can minimize or exaggerate the impact on these operations, while extreme weather events can materially constrain our operations for short periods of time.

Significant Customers

QEP's five largest customers accounted for 63%, 66% and 49%, in the aggregate, of QEP's revenues for the years ended December 31, 2020, 2019 and 2018, respectively. The following table presents the percentages by customer that accounted for 10% or more of QEP's total revenues. Management believes that the loss of any of these customers, or any other customer, would not have a material effect on the financial position or results of operations of QEP, since there are numerous potential purchasers of its production. Refer to Part I, Item 1A- Risk Factors, in this Annual Report on Form 10-K for additional discussion of QEP's competition.

Year Ended December 31, 2020	
Valero Marketing & Supply Company	**30 %**
Phillips 66 Company	**12 %**
Year Ended December 31, 2019	
Occidental Energy Marketing	21 %
Valero Marketing & Supply Company	18 %
Plains Marketing LP	17 %
Year Ended December 31, 2018	
Occidental Energy Marketing	16 %
Plains Marketing LP	12 %

Competition

QEP faces competition in every facet of its business, including the acquisition of producing leaseholds, wells and undeveloped leaseholds, the marketing of oil and condensate, gas and NGL products and the procurement of goods, services and labor. The Company's competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers and major pipeline companies, as well as participants in other industries supplying energy, fuel and services to consumers.

Human Capital Measures

Employees
At QEP, people are our most important asset. At December 31, 2020 and 2019, QEP had 257 and 248 employees, respectively. As of December 31, 2020, 52 employees were in the Permian Basin operating area, 39 employees were in the Williston Basin operating area and 166 employees were in our Denver corporate headquarters. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Health, Safety & Environment (HSE)
QEP strives to minimize our impact to the environment where we operate, and we focus on the protection of the health, safety and well-being of our employees, contractors, families, friends and neighbors. These are fundamental responsibilities of our company and of each employee. We believe that no aspect of our operations is of greater importance. Our adherence to industry regulations and state-of-the-art well construction methods, paired with ongoing water, air and land conservation initiatives, help to ensure we conduct our business with respect and care for the environment, and manage risks to drive sustainable business growth. Our HSE program includes the following results and practices:

- During the year ended December 31, 2020, QEP had zero recordable injuries for employees. During the year ended December 31, 2019, the total recordable injury rate (TRIR) for employees was 0.32.
- All employees and contractors performing work on QEP sites are required to participate in orientations prior to the commencement of work.
- Employees and contractors working for QEP have the authority and the responsibility to stop any job or work that they feel is unsafe or poses a threat to the environment.
- Our governance model ensures that we are upholding our commitment to HSE and includes: (1) integration of HSE metrics in QEP’s pay and annual incentive plan; (2) monthly and quarterly reviews of HSE performance, including key performance indicators, with our Board, management and employees; (3) compliance testing through an internal audit program; and (4) organizational focus on continuous improvement.
- QEP’s HSE Policy is posted on our website.

Culture
Respectful, resourceful and responsible are the foundation of our values as we work to achieve our vision and mission. QEP’s culture model, “How We Work Together,” consists of the following pillars: transparency, humility, inclusion, alignment and execution, in addition to our core focus on HSE.

Inclusion & Diversity
Consistent with our values, QEP is committed to providing an inclusive work environment that recognizes the contributions of individuals with varied backgrounds, perspectives and personal attributes. We seek to promote inclusion and diversity (I&D) in our workforce through our focus on inclusion in our culture model and through training and development. We strive to improve our record on I&D through our promotion and hiring practices.

At December 31, 2020, women and minorities accounted for approximately 32% and 18%, respectively, of our total workforce and two of the seven seats on our Board were held by women, including our Board Chair. Female Board directors also chair one-third of our Board Committees.

QEP invested in several company-wide initiatives in 2020 to further our focus on I&D, including:
- I&D training completed by QEP employees and our Board;
- Launching our first I&D employee survey to identify areas where QEP is doing well and areas where we can continue to evolve and improve;
- Fostering communications among employees of varied backgrounds, perspectives and experiences, through various QEP sponsored employee programs; and
- Supporting I&D through our community volunteering and investment program, QEP Cares.

Recruiting & Hiring Practices
At QEP, we strive to recruit and hire qualified employees who are seeking challenging opportunities in a fast-paced, results-focused culture that values safety and rewards performance. QEP is proud of its work environment that respects the dignity and diversity of each individual and considers applications for employment without regard to the applicant's race, color, national origin, sex, religion, creed, age, sexual orientation, gender identity, marital status, disability, protected veterans or any other characteristics protected by law. QEP's equal employment opportunity policy applies to all persons involved in our operations and activities, including recruiting, hiring, training, transfers, promotions and benefits.

Compensation and Benefits
QEP strives to be an employer of choice in our industry. We offer a flexible and competitive compensation and benefits program, designed to help employees and their families grow personally, professionally and financially, including:
- Industry-competitive, performance-based compensation;
- Annual incentive plan based on company-wide performance targets and individual contributions;
- Long-term incentives, including stock-based compensation plans to share in QEP's success;
- Industry-competitive benefits designed for flexibility and meeting personal needs, including comprehensive health and welfare plans and a 401(k) program with company contributions and matching; and
- Company matching charitable giving programs and volunteer paid time off.

Training & Development
QEP invests in our employees' professional growth to build strong teams and develop leaders for today and the future. We build our dynamic team of industry leading professionals by engaging them in interesting and rewarding work and by providing training and development opportunities. In addition to ongoing operations and compliance training, in 2020 we delivered courses in safety, professional development, performance management, information technology skills, business functional skills, I&D and leadership skills.

Due to the COVID-19 pandemic, we adjusted our training delivery methods by offering virtual training whenever possible to ensure employees were able to participate safely. Additionally, QEP is proud to offer an education reimbursement benefit to employees to complete applicable post-secondary courses.

Succession Planning
In 2020, QEP conducted a comprehensive succession planning process that involved assessment of talent across the organization. We evaluated employee performance and potential as well as readiness of potential successors for key roles and developmental needs. Succession planning informs our executives and Board in making compensation, development and promotional decisions. The succession process includes creating development plans to ensure our leaders are ready to take the next step in their careers and evaluating our bench strength for key positions as well as talent gaps within the organization. Succession planning occurs annually to ensure the continuity of our business and to provide challenging and rewarding career opportunities for our employees.

Information about our Executive Officers

The name, age, period of service, title and business experience of each of QEP's executive officers as of February 17, 2021, are listed below:

Timothy J. Cutt	60	President and Chief Executive Officer (January 2019 to present). Prior to joining QEP, Mr. Cutt was the Chief Executive Officer of Cobalt International Energy, a development-stage petroleum exploration and production company (2016 to 2018). Cobalt International voluntarily filed a petition for relief under Chapter 11 of the United States Bankruptcy Code on December 14, 2017, and a plan to sell all the assets of the company was approved on April 10, 2018. Prior to joining Cobalt International, Mr. Cutt served as President of the Petroleum Division of BHP Billiton, a global natural resources company (2013 to 2016), and prior to that he also served as President of Production for BHP Billiton's Petroleum Division (2007 to 2011). Prior to joining BHP Billiton, Mr. Cutt served in various roles at ExxonMobil in the prior 25 years, including President of ExxonMobil de Venezuela (2005 to 2007), President ExxonMobil Canada Energy (2004 to 2005), President Hibernia Management & Development Company (2001 to 2004) and Regional Coordinator, North America (2000 to 2001).
Christopher K. Woosley	51	Executive Vice President, General Counsel and Corporate Secretary (January 2020 to present). Senior Vice President and General Counsel (2017 to 2019). Vice President and General Counsel (2012 to 2016).Corporate Secretary (2016 to 2017). Senior Attorney (2010 to 2012). Prior to joining QEP, Mr. Woosley was a partner in the law firm Cooper Newsome & Woosley PLLP (2003 to 2010).
William J. Buese	49	Vice President, Chief Financial Officer and Treasurer (January 2020 to present). Vice President Finance and Treasurer (2014-2019). Director of Finance (2012-2014). Prior to joining QEP, Mr. Buese was Director, Finance at MarkWest Energy Partners, LP, and served in various finance, treasury, accounting and investor relations roles (2005-2012). Prior to joining MarkWest, Mr. Buese was employed in a non-energy-related industry for more than 10 years.
Joseph T. Redman	43	Vice President, Energy (2019 to present). Vice President, Western Region (2017 to 2019). General Manager (2012-2017). Operations and Engineering Manager (2010-2012). Previous titles with Questar Corporation: Staff Petroleum Engineer/Supervisor ((2010). Senior Petroleum Engineer (2008-2010). Reservoir Engineer (2006-2008). Prior to joining Questar, Mr. Redman worked in the pipeline industry.

There is no family relationship between any of the listed officers or between any of them and the Company's Board of Directors. The executive officers serve at the pleasure of the Company's Board of Directors. There is no arrangement or understanding under which any of the officers were selected.

Government Regulation

QEP's business operations are subject to a wide range of local, state, tribal and federal statutes, rules, orders and regulations. The regulatory environment in which the oil and gas industry operates increases the cost of doing business and consequently affects profitability. The following discussion of certain laws and regulations should not be considered an exhaustive review of all regulatory considerations affecting QEP's operations. See additional discussion of regulations under Part I, Item 1A – Risk Factors, in this Annual Report on Form 10-K. Moreover, uncertainty about the future course of regulation exists because of the recent change in the U.S. presidential administration. In January 2021, the current administration issued an executive order directing all federal agencies to review and take action to address any federal regulations, orders, guidance documents, policies and any similar agency actions promulgated during the prior administration that may be inconsistent with the administration’s policies. As a result, it is unclear the degree to which certain recent regulatory developments may be modified or rescinded. The executive order also established an Interagency Working Group on the Social Cost of Greenhouse Gases (Working Group), which is called on to, among other things, develop methodologies for calculating the “social cost of carbon,” “social cost of nitrous oxide” and “social cost of methane." Recommendations from the Working Group are due beginning June 1, 2021, and final recommendations no later than January 2022. Further regulation of air emissions, as well as uncertainty regarding the future course of regulation, could eventually reduce the demand for oil and natural gas. Also in January 2021, the current administration issued an executive order focused on addressing climate change (2021 Climate Change Executive Order). Among other things, the 2021 Climate Change Executive Order directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands or in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs. The 2021 Climate Change Executive Order also directs the federal government to identify "fossil fuel subsidies" to take steps to ensure that, to the extent consistent with applicable law, federal funding is not directly subsidizing fossil fuels. Legal challenges to the suspension have already been filed and are currently pending.

Regulation of Exploration and Production Activities

The regulation of oil and gas E&P activities is a broad and increasingly complex area, notably including laws and regulations governing the potential discharge or release of materials into the environment or otherwise relating to environmental protection. These laws and regulations include, but are not limited to, the following:

Clean Air Act. The federal Clean Air Act and similar state laws regulate the emission of air pollutants from equipment and facilities employed by QEP in its business, including, but not limited to, engines, tanks and dehydrators. In 2012 and 2016, the Environmental Protection Agency (EPA) adopted various regulations specific to oil and gas exploration, production, gathering and processing, which impose air quality controls and work practices, and govern source determination and permitting requirements, and methane emissions. In September 2018, the EPA announced proposed revisions to the various regulations which may reduce compliance burdens on some facilities. In August 2019, the EPA proposed two options for further revising its methane regulations. In August 2020, the EPA adopted deregulatory amendments to the 2016 rule intended to streamline implementation, reduce duplicative EPA and state requirements and decrease the burden of compliance. In particular, the amendments removed the transmission and storage segments from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. Several lawsuits were filed challenging these amendments, and the U.S. Court of Appeals for the D.C. Circuit ordered an administrative stay of these amendments shortly after they were finalized. Although the administrative stay was lifted in October 2020, which brought the amendments into effect, the amendments may still be subject to reversal under the current presidential administration. In January 2021, the administration issued an executive order calling on the EPA to, among other things, consider a proposed rule suspending, revising or rescinding the deregulatory amendments by September 2021. Regulatory uncertainty surrounding the implementation of such revisions and the potential for legal challenges to them pose some complications for QEP's ongoing operations and compliance efforts. Additionally, many states are adopting air permitting and other air quality control regulations specific to oil and gas exploration, production, gathering and processing that are more stringent than existing requirements under federal regulations. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues.

In June 2016, the EPA issued a Federal Implementation Plan (FIP) to implement the Federal Minor New Source Review Program on tribal lands for oil and gas production. The FIP primarily impacts QEP's operations on the Fort Berthold Reservation in the Williston Basin. The FIP creates a permit-by-rule process for minor sources that also incorporates emission limits and other requirements under various federal air quality standards, applying them to a range of equipment and processes used in oil and gas production and gathering.

Greenhouse Gas Regulations and Climate Change Legislation. In recent years, the EPA has adopted and substantially expanded regulations for the measurement and annual reporting of carbon dioxide, methane and other GHG emitted from certain large facilities, including onshore oil and gas production, processing, transmission, storage and distribution facilities. In addition, both houses of Congress have considered legislation to reduce emissions of GHG, and a number of states have taken, or are considering taking, legal measures to reduce emissions of GHG, primarily through the development of GHG inventories, GHG permitting, state or regional GHG cap and trade programs, and/or mandates for the use of renewable energy. Many states and local governments are undertaking efforts to meet climate goals which could restrict development of oil and gas as well as lessen demand depending on the specific initiatives. Foreign governments' pursuit of climate change goals could also impact demand and reduce prices on U.S. oil and natural gas. In January 2021, President Biden issued the 2021 Climate Change Executive Order that, among other things, sets goals of a carbon pollution free power sector by 2035 and a net zero economy by 2050. It also commenced the process for the U.S. reentering the Paris Climate Agreement, although the emissions pledges in connection with that effort have not yet been updated. The 2021 Climate Change Executive Order starts a process of developing a U.S. emissions target as well as a climate finance plan.

Bureau of Land Management Venting and Flaring Regulations. In November 2016, the Department of the Interior's Bureau of Land Management (BLM) finalized a rule to further control the venting, flaring and emission of natural gas on BLM and tribal leases (2016 Waste Prevention Rule). In September 2018, the BLM finalized a rule that revised and replaced the 2016 Waste Prevention Rule, effective November 2018 (2018 Revised Waste Prevention Rule). The Revised Waste Prevention Rule rescinds certain provisions of the 2016 Waste Prevention Rule, revises other provisions of the 2016 Waste Prevention Rule, and adds provisions deeming gas vented or flared in accordance with applicable state or tribal requirements to be royalty free. In July and October 2020, after several years of litigation, federal courts struck down both the BLM’s 2016 Waste Prevention Rule and its 2018 Revised Waste Prevention Rule. The effect of these orders combined is to essentially reinstate the previous rule, Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases: Royalty or Compensation for Oil and Gas Lost (NTL-4A). The 2021 Climate Change Executive Order directs the Secretary of Interior to impose a moratorium on new oil and natural gas leases on public lands, or offshore waters to the extent possible, and launch a rigorous review of all existing leasing and permitting practices related to fossil fuel development on public lands. This moratorium may include restrictions of approving right-of-ways that could help build out midstream infrastructure needed to help reduce flaring.

Other BLM Regulations. In November 2016, the BLM finalized regulations that update and replace Onshore Orders No. 3 (Site Security), No. 4 (Measurement of Oil) and No. 5 (Measurement of Gas). These regulations increase compliance burdens on federal lessees and operators like QEP by requiring such lessees or operators to obtain numbers for all onshore points of federal royalty measurement from the BLM, adjusting recordkeeping requirements, and by imposing new oil and gas measurement equipment standards, among other requirements, for production from federal and Indian leases. Although these regulations took effect in January 2017, the BLM has delayed the requirement to obtain numbers for all onshore points of federal royalty measurement.

Clean Water Act and Safe Drinking Water Act. The federal Clean Water Act and similar state laws regulate discharges of wastewater, oil, fill material, and other pollutants into regulated "Waters of the United States" (or WOTUS). These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil. The scope of what areas constitute jurisdictional WOTUS regulated under the Clean Water Act has been the subject of litigation and related administrative matters since the EPA and the U.S. Army Corps of Engineers (Corps) in 2015 proposed to revise and expand the definition of WOTUS (2015 WOTUS Rule). However, in October 2019, the EPA and the Corps published a final rule repealing the 2015 WOTUS Rule and re-codifying the longstanding and familiar regulatory text that existed prior to the 2015 Rule. In January 2020, a new WOTUS rule (Navigable Waters Protection Rule) was finalized which replaced the 2015 rule. Under the final rule, the following four categories of waters would be defined as WOTUS: traditional navigable waters and territorial seas; perennial and intermittent tributaries to those waters; lakes, ponds and impoundments of jurisdictional waters. A federal district court issued a preliminary injunction preventing the Navigable Waters Protection Rule from taking effect in Colorado, but the rule is otherwise effective in every other state. Additional litigation and administrative proceedings are expected in the future. In addition, in April 2020, the U.S. Supreme Court issued a decision finding that point source discharges to navigable waters through groundwater are subject to regulation under the Clean Water Act. The U.S. Supreme Court specifically held that the Clean Water Act requires a permit if the addition of the pollutants through groundwater is the “functional equivalent” of a direct discharge from the point source into navigable waters. Areas regulated under comparable state laws are generally defined more broadly. The federal Safe Drinking Water Act (SDWA) and comparable state statutes strictly regulate the disposal of wastes via underground injection wells, including the disposal of produced water and other fluids generated during oil and gas production well development, to protect drinking water resources.

In January 2017, the Corps issued revised and renewed streamlined general nationwide permits (NWP) that are available to satisfy permitting requirements for certain work in streams, wetlands and other waters of the United States under Section 404 of the Clear Water Act and Section 10 of the Rivers and Harbors Act. The new NWPs took effect in March 2017, or when certified by each state, whichever was later. The oil and gas industry broadly utilizes NWPs 12, 14, and 39 for the construction, maintenance and repair of pipelines, roads, and drill pads, respectively, and related structures in waters of the United States that impact less than a half-acre of waters of the United States and meet the other criteria of each NWP. Other regional and statewide general permits are available in certain states that also authorize such activities under those statutes. In April 2020, the U.S. District Court for the District of Montana vacated the Corps' 2017 issuance of NWP 12 (the general permit issued by the Corps for pipelines and utility projects). In May 2020, the court narrowed its ruling, vacating and enjoining the use of NWP 12 only as it relates to construction of new oil and gas pipelines. The Corps appealed the decision to the U.S. Court of Appeals for the Ninth Circuit and the litigation is ongoing. In July 2020, the U.S. Supreme Court granted in part and denied in part the Corps' application for stay of the order issued by the district court. The U.S. Supreme Court stayed the lower court order except as it applies to the Keystone XL pipeline. The stay is to remain in place pending disposition of the appeal currently pending before the Ninth Circuit. In January 2021, the Corps released the final version of a rule renewing twelve of its NWPs, including NWP 12. The new rule splits NWP 12 into three parts; NWP 12 will continue to be available for oil and gas pipelines, while new NWP 57 will be available for electric utility line and telecommunications activities, and a new NWP 58 will be available for utility line activities for water and other substances. The new rule also eliminates preconstruction notice requirements for NWP 12 for several conditions that used to require such notice, but also now requires new oil and gas pipeline projects that exceed 250 miles in length to give preconstruction notice and obtain approval before proceeding. We cannot predict at this time how the new rule will be implemented, because permits are issued by the local Corps district offices, or whether it will remain in place following the review required by the Biden executive orders. However, if new oil and gas pipeline projects are unable to utilize NWP 12 or identify an alternate means of Clean Water Act compliance, such projects could be significantly delayed, which could have an adverse impact on our operations.

Oil Pollution Act of 1990. The federal Oil Pollution Act of 1990 (OPA) and regulations issued under the OPA impose strict, joint and several liability on "responsible parties" for removal costs and damages to natural resources resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States.

Comprehensive Environmental Response, Compensation and Liability Act of 1980. The federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA or Superfund) and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. Such responsible persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances released into the environment and for damage to natural resources. Such liability is in addition to claims for personal injury and property damage caused by the release of hazardous substances into the environment, which may also be made by third parties.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act (RCRA) is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements on a person who is either a "generator" or "transporter" of hazardous waste or an "owner" or "operator" of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of oil, gas or geothermal energy." Any repeal or modification of this RCRA oil and gas exploration and production waste exemption would increase the volume of hazardous waste QEP is required to manage and dispose of and would cause QEP, as well as its competitors, to incur increased operating expenses. In December 2016, the U.S. District Court for the District of Columbia approved a consent decree between the EPA and a coalition of ENGOs. The consent decree requires the EPA to review and determine whether it will revise the RCRA regulations for exploration and production waste to treat such waste as hazardous waste. The EPA concluded in 2019 that they did not need to regulate "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of oil, gas or geothermal energy" after they reviewed the RCRA regulations for exploration and production waste. The EPA concluded that states were adequately regulating exploration and production waste under the subsection "D" provision of RCRA. The subsection "D" provision that provides for EPA exemption and provides for state management of said waste is reviewable by the EPA every three years.

Hydraulic Fracturing Regulations. QEP's current and future production and oil and gas reserves are derived from reservoirs that require hydraulic fracture stimulation to be commercially viable. Hydraulic fracture stimulation involves pumping fluid at high pressure into tight sand or shale reservoirs to artificially induce fractures. The artificially induced fractures allow better connection between the wellbore and the surrounding reservoir rock, thereby enhancing the productive capacity and ultimate hydrocarbon recovery of each well. The fracture stimulation fluid is typically composed of over 99% water and sand, with the remaining constituents consisting of chemical additives designed to optimize the fracture stimulation treatment and production from the reservoir. QEP discloses the contents of hydraulic fracturing fluids and submits information regarding its wells and the fluids used in them, to the national online disclosure registry, FracFocus (www.fracfocus.org), and to state registries where required.

QEP obtains water for fracture stimulations from a variety of sources, including industrial water wells and surface water sources. When technically and economically feasible, QEP recycles flow-back and produced water for use in fracture stimulation, which reduces water consumption from surface and groundwater sources and reduces produced water disposal volumes. QEP transports both fresh and produced water by pipeline instead of truck when feasible to avoid truck traffic and emissions. QEP believes that the employment of fracture stimulation technology does not present any significant additional risks other than those associated with the disposal of waste water (see Item 1A - Risk Factors for more information) and those generally associated with oil and gas drilling, completion and production operations, such as the risk of spills, releases, discharges, accidents and injuries to persons and property.

Almost all oil and gas producing states require disclosure of the chemicals used in hydraulic fracturing and some form of reporting after a well is fractured. Some states have adopted additional requirements for hydraulic fracturing, such as notice to the surface owner or others, wellbore testing, ground water sampling, waste handling, and seismic monitoring. Other states rely for this purpose upon their existing regulatory programs for permitting wells, ensuring wellbore integrity, managing waste, and overseeing oil and gas development. A few states have imposed moratoria on hydraulic fracturing, but QEP does not operate in those states.

Federal regulation of hydraulic fracturing is currently limited but evolving. The EPA has regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA, but QEP does not use diesel fuel in any of its hydraulic fracturing fluids. In recent years, the EPA has adopted pretreatment standards under the Clean Water Act for hydraulic fracturing effluent, issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to obtain data on hydraulic fracturing chemicals, and published a multi-year study on potential impacts to drinking water from hydraulic fracturing. Also, in 2016, the Occupational Safety and Health Administration (OSHA) adopted employee-protection requirements regarding silica, which is used in hydraulic fracturing fluids.

Tribal Lands and Minerals. Various federal agencies within the U.S. Department of the Interior, particularly the BLM and the Bureau of Indian Affairs (BIA), along with certain Native American tribes, promulgate and enforce regulations pertaining to oil and gas operations on Native American tribal lands and minerals where QEP operates. These regulations include, but are not limited to, such matters as lease provisions, drilling and production requirements, surface use restrictions, environmental standards, royalty considerations and taxes. In March 2016, the BIA implemented regulations significantly altering the procedure for obtaining rights-of-way on tribal lands. In certain cases, these new regulations have increased the time and cost required to obtain necessary rights-of-ways for operation on tribal lands for QEP and its competitors. The 2021 Climate Change Executive Order creates a moratorium on new oil and natural gas leases on public lands, or offshore waters to the extent possible, and launches a rigorous review of all existing leasing and permitting practices related to fossil fuel development on public lands. The executive order does not restrict energy activities on lands that the U.S. holds in trust for tribes. It is unclear how it impacts allotted lands and whether the executive order exempting tribal lands will continue to be exempt from the 2021 Climate Change Executive Order.

Endangered Species Act and National Environmental Policy Act. To develop federal or Indian leases, QEP must obtain authorizations from federal agencies, such as drilling permits and rights-of-way. Prior to issuing such authorizations, federal agencies must comply with both the Endangered Species Act and National Environmental Policy Act (NEPA). The Endangered Species Act restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal or permanent ban in affected areas. NEPA requires that federal agencies assess the direct, indirect and cumulative environmental impacts of their authorizations. This analysis is done in Environmental Assessments or Environmental Impact Statements prepared for a lead agency under the Council on Environmental Quality (CEQ) and other agency regulations, usually for the BLM in the areas where QEP operates. In January 2020, the CEQ announced a notice of proposed rulemaking to update procedural provisions and modernization of NEPA. The rulemaking was finalized in July 2020.

Emergency Planning and Community Right-to-Know Act and Occupational Safety and Health Act. Pursuant to the Emergency Planning and Community Right-to-Know Act (EPCRA), facilities that store, use or release certain chemicals are subject to various reporting requirements. EPCRA requirements include emergency planning notification, emergency release notification, and emergency and chemical inventory reporting to state and local emergency planning committees and emergency response departments. In January 2017, the EPA proposed to add natural gas processing facilities to the list of industrial facilities that must report under EPCRA's Toxic Release Inventory, but the proposed rule has not been finalized. OSHA establishes workplace standards for the protection of the health and safety of employees, including the implementation of a hazard communication program designed to inform all downstream users, including employees, about hazardous chemicals in the workplace, potential harmful effects of these chemicals, and appropriate control measures.

Transportation Regulations

Regulation of the Transportation and Sale of Natural Gas. The FERC regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 (Natural Gas Act) and the Natural Gas Policy Act of 1978 and regulations issued under those Acts. 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. The gathering of natural gas is exempt from FERC regulation under the Natural Gas Act (referred to as "non-jurisdictional" gatherer and gathering lines/systems). However, there is no bright-line test for determining jurisdictional status. Under FERC's current regulatory regime, transmission services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Our gas gathering system is not currently subject to state public utility regulations.

Regulation of Interstate Crude Oil Pipelines. Some of QEP's crude oil pipelines are subject to regulation by the Texas Railroad Commission (TRRC). The applicable state statutes require that pipeline rates be nondiscriminatory and provide no more than a fair return on the aggregate value of the pipeline property used to render services. QEP's crude oil pipelines (specifically the rates, terms and conditions for shipments) may also be subject to FERC regulation if QEP's crude oil pipelines provide part of the movement in interstate or foreign commerce for shippers (pursuant to the Interstate Commerce Act, as it existed on October 1, 1977, the Energy Policy Act of 1992 and related rules). QEP does not control the entire transportation path of all crude oil shipped on QEP's pipelines. Therefore, FERC regulation could be triggered by QEP's customers' transportation decisions.

Regulation of Pipeline Safety. QEP operates one crude oil pipeline subject to regulation by the Department of Transportation, through the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA), with respect to crude oil. The NGPSA and HLPSA, as amended, govern the design, installation, testing, construction, operation, replacement and management of natural gas as well as crude oil, NGL and condensate pipeline facilities. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 amended the NGPSA in an effort to reform PHMSA and to close potential gaps in federal pipeline safety regulation, as well as to increase the penalties for violations. Following those acts, PHMSA has proposed numerous changes to its regulations under the NGPSA, including expanding the scope of safety regulation of gathering pipelines. Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations. However, we may incur additional compliance costs if PHMSA adopts new pipeline safety regulations in the future. For instance, in October 2019, PHMSA submitted three major rules to the Federal Register, including rules focused on: the safety of gas transmission pipelines (the first of three parts of the so-called PHMSA gas “Mega Rule” which took effect July 1, 2020); the safety of hazardous liquid pipelines; and enhanced emergency order procedures. PHMSA is expected to issue the second and third parts of the gas Mega Rule soon.

Transporting Crude Oil by Rail. QEP sells crude oil to customers that may transport crude oil by rail. In 2015, the U.S. Department of Transportation issued a final rule regarding the safe transportation of flammable liquids by rail. The final rule imposes certain requirements on "offerors" of crude oil, including sampling, testing and certification requirements to improve classification of energy products placed into transport.

Crude Oil Export. The Consolidated Appropriations Act of 2016 (HR 2029) included a provision to end the export ban on domestic crude oil. The Consolidated Appropriations Act of 2016 (HR 2029) passed both houses of Congress and was signed by President Obama in 2015. While QEP does not export crude oil, any restrictions by Congress or the President to limit crude oil exports could reduce domestic prices received by QEP.

State Regulations

The states where QEP operates have promulgated extensive and complex regulations that govern oil and gas development within their respective boundaries. These regulations generally increase the cost of constructing, operating, producing and abandoning wells, and violations may result in civil penalties and affect QEP's ability to operate. The following are examples of these state regulations.

Texas. In 2014, the TRRC adopted new permit rules for injection wells to address seismic activity concerns within the state. Among other things, the rules require companies seeking permits for produced water disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the TRRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Also in 2014, the TRRC adopted additional well integrity, casing, and cementing requirements for hydraulically fractured wells. In 2016, the TRRC conformed its administrative practices and procedures for horizontally drilled and hydraulically fractured well fields to those applicable to other types of oil and gas well development. Natural gas flaring in Texas has increased over the past years and the TRRC may implement regulations or restrictions on flaring of natural gas which could increase production costs to QEP or restrict production of crude oil.

North Dakota. The North Dakota Industrial Commission (NDI Commission), North Dakota's chief energy regulator, issued an order in 2014 to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In connection with that order, the NDI Commission required operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain well operators that cannot meet the capture goals. In addition, pursuant to Commission Order No. 25417, QEP is required to condition crude oil produced in the Bakken Petroleum System to remove lighter, volatile hydrocarbons and reduce the vapor pressure of crude oil prior to rail transport.

ITEM 1A. RISK FACTORS

Described below are certain risks that we believe are applicable to our business and the oil and gas industry in which we operate. Investors should read carefully the following factors as well as the cautionary statements referred to in "Forward-Looking Statements" herein. If any of the risks and uncertainties described below or elsewhere in this Annual Report on Form 10-K actually occur, the Company's business, financial condition or results of operations could be materially adversely affected.

Risk Factor Summary

- The prices for oil, gas and NGL are volatile, and declines in such prices could adversely affect QEP's earnings, cash flows, asset values and stock price.
- The outbreak of COVID-19 and recent oil market developments could adversely impact our financial condition and results of operations.
- Lack of availability of refining, gas processing, storage, gathering or transportation capacity will likely impact results of operations.
- Lower oil, gas and NGL prices or negative adjustments to oil, gas and NGL reserves may result in significant impairment charges.
- Oil and gas reserve estimates are imprecise, may prove to be inaccurate, and are subject to revision. Any significant inaccuracies in QEP's reserve estimates or underlying assumptions may negatively affect the quantities and present value of QEP's reserves.
- QEP may be required to write down its proved undeveloped reserve estimates if it is unable to convert those reserves into proved developed reserves within five years.
- Shortages of qualified personnel and/or oilfield equipment and services as well as QEP's inability to retain or motivate key personnel or transfer knowledge from retiring personnel could negatively impact results of operations.
- Multi-well pad drilling may result in volatility in QEP operating results and delay conversion of PUD reserves.
- Certain of QEP's leaseholds are subject to lease and other agreements that will expire over the next several years unless production in paying quantities is established and maintained on the acreage or on units containing the acreage, certain drilling obligations are satisfied, or the leases are otherwise renewed or extended.
- QEP's identified potential well locations are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, QEP may not be able to raise the substantial amount of capital that would be necessary to drill its potential well locations.
- Because the exchange ratio is fixed and because the market price of Diamondback common stock will fluctuate, QEP stockholders cannot be certain of the precise value of the Merger Consideration they will receive in the Merger.

- The Merger may not be completed and the Merger Agreement may be terminated in accordance with its terms. Failure to complete the Merger could negatively impact the price of shares of our common stock, as well as our future business and financial results.
- Our stockholders will have a reduced ownership and voting interest in the combined company after the Merger compared to their current ownership in QEP and will exercise less influence over the combined company's management.
- If the Merger does not qualify as a "reorganization" under Section 368(a) of the Internal Revenue Code of 1986, as amended (Code), our stockholders may be subject to U.S. federal income tax upon the receipt of Diamondback common stock in the Merger.
- We are subject to business uncertainties while the Merger is pending, which could adversely affect our business.
- The Merger Agreement limits our ability to pursue alternatives to the Merger, which may discourage certain other companies from making favorable alternative transaction proposals and, in specified circumstances, could require us to pay Diamondback a termination fee.
- Our directors and executive officers may have interests in the Merger that are different from, or in addition to, the interests of our stockholders.
- We will incur significant transaction and merger-related costs in connection with the Merger, which may be in excess of those anticipated.
- Completion of the Merger may trigger change in control or other provisions in certain agreements to which we or our subsidiaries are a party.
- We may be targets of securities class action and derivative lawsuits that could result in substantial costs and may delay or prevent the Merger from being completed.
- Shares of Diamondback common stock received by our stockholders as a result of the Merger will have different rights from shares of our common stock.
- QEP's certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if an acquisition or merger may be in QEP shareholders' best interests.
- Substantially all of our producing properties and operations are located in the Permian and Williston basins, making us vulnerable to risks associated with operating in a limited number of basins.
- QEP may be unable to divest assets on financially attractive terms, resulting in reduced cash proceeds.
- QEP is partially dependent on its revolving credit facility and continued access to capital markets to successfully execute its operating strategies.
- A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital.
- QEP's use of derivative instruments to manage exposure to uncertain prices could result in financial losses or reduce its income.
- QEP is involved in legal proceedings that could result in substantial liabilities and materially and adversely impact the Company's financial condition.
- QEP is subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect its cost of doing business and recording of proved reserves.
- Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations.
- QEP may not be able to obtain the permits and approvals necessary to continue and expand its operations.
- Our operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal, state, local and tribal regulations and laws, any of which may increase our costs and have an adverse impact on our ability to effectively conduct our operations.
- Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to oil and gas reserves.
- Legislation or regulatory initiatives intended to address induced seismicity could restrict QEP's drilling and production activities as well as QEP's ability to dispose of produced water gathered from such activities, which could have a material adverse effect on QEP's business.
- Climate change and climate change legislation and regulatory initiatives, including renewable energy mandates could result in increased operating costs and decreased demand for the oil and natural gas that we produce.
- A change in the jurisdictional characterization of some of our assets by federal, state, or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase.
- The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business.
- If we were to experience an "ownership change," we could be limited in our ability to use certain tax attributes arising prior to the ownership change to offset future taxable income.

Risks Related to the Business

The prices for oil, gas and NGL are volatile, and declines in such prices could adversely affect QEP's earnings, cash flows, asset values and stock price. Historically, oil, gas and NGL prices have been volatile and unpredictable, and that volatility is expected to continue. Volatility in oil, gas and NGL prices is due to a variety of factors that are beyond QEP's control, including:

- changes in local, regional, domestic and foreign supply of and demand for oil, gas and NGL;
- the impact of an abundance of oil, gas and NGL from unconventional sources on the global and local energy supply;
- the level of imports and/or exports of, and the price of, foreign oil, gas and NGL;
- localized supply and demand fundamentals, including the proximity, cost and availability of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the availability of refining and storage capacity;
- domestic and global economic and political conditions;
- changes in government energy policies, including imposed price controls or product subsidies or both;
- periods of civil unrest;
- speculative trading in crude oil and natural gas derivative contracts;
- the continued threat of terrorism and the impact of military and other action;
- the activities of the Organization of Petroleum Exporting Countries (OPEC) and other oil producing countries such as Russia and Saudi Arabia, including the ability of members of OPEC and Russia to maintain oil price and production controls;
- events in the Middle East, Africa, South America and Russia;
- the strength of the U.S. dollar relative to other currencies;
- weather conditions, natural disasters and epidemic or pandemic disasters such as the recent outbreak of COVID-19;
- domestic and international laws, regulations and taxes, including regulations, legislation or executive orders relating to climate change, induced seismicity or oil and gas exploration and production activities, including, but not limited to hydraulic fracturing;
- technological advances affecting energy consumption and energy supply;
- conservation efforts;
- the price, availability and acceptance of alternative energy sources, including coal, nuclear energy, renewables and biofuels;
- demand for electricity and natural gas used as fuel for electricity generation;
- pandemic and health events that could reduce demand of petroleum products;
- pandemic events that could impair our employees' and contractors' abilities to drill and produce oil and gas;
- the level of global oil, gas and NGL inventories and exploration and production activity; and
- the quality of oil and gas produced.

Declines in oil, gas and NGL prices would not only reduce revenue, but could also reduce the amount of oil, gas and NGL that we can economically produce and therefore potentially lower our oil and gas reserve quantities. In addition, a decline in oil and gas prices and volatility could negatively impact our ability to execute our operating and development plans and the ability to generate Free Cash Flow.

The long-term effect of factors impacting the prices of oil, gas and NGL is uncertain. Substantial or prolonged declines in these commodity prices may have the following effects on QEP's business:

- adversely affect QEP's financial condition and liquidity and QEP's ability to finance planned capital expenditures, borrow money, repay debt and raise additional capital;
- reduce the amount of oil, gas and NGL that QEP can produce economically;
- reduce the carrying value of QEP's oil and gas properties due to recognizing additional impairments of proved and unproved properties;
- cause QEP to delay, postpone or cancel some of its capital projects;
- cause QEP to divest properties to generate funds to meet cash flow or liquidity requirements;
- reduce QEP's revenues, operating income or cash flows;
- limit QEP's ability to generate Free Cash Flow;
- reduce the amounts of QEP's estimated proved oil, gas and NGL reserves;
- limit QEP's access to, or increasing the cost of, sources of capital such as equity and long-term debt;
- cause additional counterparty credit risk;
- decrease the value of QEP's common stock; and
- increase shareholder activism.

Alternatively, higher oil prices may result in increased volatility in commodity prices, inflation, slower economic growth, a global recession or more international conflicts. Higher oil prices may also result in higher costs for QEP and significant mark-to-market losses being incurred in QEP's commodity derivatives, which may in turn cause us to experience net losses.

QEP's operations are subject to operational hazards and unforeseen interruptions for which QEP may not be adequately insured and that could adversely affect our business, financial condition and results of operations. There are operational risks associated with the exploration, production, gathering, transporting, and storage of oil, gas and NGL, including:

- pandemic health events, injuries and/or deaths of employees, supplier personnel, or other individuals;
- fires, explosions and blowouts;
- earthquakes and other natural disasters;
- aging infrastructure and mechanical problems;
- unexpected drilling conditions, including abnormally pressured formations or loss of drilling fluid circulation;
- pipe, cement or casing failures;
- equipment malfunctions, mechanical failures or accidents;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- adverse weather conditions;
- plant, pipeline, railway and other facility accidents and failures;
- truck and rail loading and unloading problems;
- delays imposed by or resulting from compliance with regulatory requirements;
- delays in or limits on the issuance of drilling permits on our federal leases, including as a result of government shutdowns;
- delays imposed by or resulting from legal proceedings;
- environmental accidents such as oil spills, natural gas leaks, pipeline or tank ruptures, or discharges of air pollutants, brine water or well fluids into the environment;
- security breaches, cyberattacks, piracy, or terrorist acts;
- flaring of natural gas, including, where required, accurate and timely payment of royalty on flared gas;
- pipeline takeaway and refining and processing capacity issues; and
- title problems.

QEP could incur substantial losses as a result of pandemic health events, injury to or loss of life, pollution or other environmental damage, damage to or destruction of property or equipment, regulatory compliance investigations, fines or curtailment of operations, or attorneys' fees and other expenses incurred in the prosecution or defense of litigation. As a working interest owner in wells operated by other companies, QEP may also be exposed to the risks enumerated above from operations that are not within its care, custody or control.

Consistent with industry practice, QEP generally indemnifies drilling contractors and oilfield service companies (collectively, contractors) against certain losses suffered by QEP as the operator and certain third parties resulting from a well blowout or fire or other uncontrolled flow of hydrocarbons, regardless of fault. Therefore, QEP may be liable, regardless of fault, for some or all of the costs of controlling a blowout, drilling a relief and/or replacement well and the cleanup of any pollution or contamination resulting from a blowout in addition to claims for personal injury or death suffered by QEP's employees and certain others. QEP's drilling contracts and oilfield service agreements, however, often provide that the contractor will indemnify QEP for claims related to injury and death of employees of the contractor and its subcontractors and for property damage suffered by the contractor and its subcontractors.

QEP's insurance coverage may not be sufficient to cover 100% of potential losses arising as a result of the foregoing risks. QEP has limited or no coverage for certain other risks, such as political risk, lost reserves, business interruption, cyber risk, earthquakes, war and terrorism. Although QEP believes the coverage and amounts of insurance that it carries are consistent with industry practice, QEP does not have insurance protection against all risks that it faces because QEP chooses not to insure certain risks, insurance is not available at a level that balances the costs of insurance and QEP's desired rates of return, or actual losses may exceed coverage limits. QEP could sustain significant losses and substantial liability for uninsured risks. The occurrence of a significant event against which QEP is not fully insured could have a material adverse effect on its financial condition, results of operations and cash flows.

The outbreak of COVID-19 and recent oil market developments could adversely impact our financial condition and results of operations. On January 30, 2020, the WHO announced a global health emergency because of a new strain of coronavirus known as COVID-19 due to the risks it imposes on the international community as the virus spreads globally. In March 2020, the WHO classified the COVID-19 outbreak as a pandemic, based on the rapid increase in exposure globally. COVID-19 has had and continues to have adverse repercussions across regional and global economies and financial markets which necessarily adversely affects the jurisdictions in which we operate and in turn, our business. The governments of many countries, including the United States, have reacted by instituting lockdowns, business shutdowns, quarantines and restrictions on travel. Businesses have also implemented countermeasures and safety measures to reduce the risk of transmission. Such actions have not only disrupted businesses but have had a material and adverse effect on industries and local, regional and global economies.

The crude oil market experienced a dramatic decline in oil prices in response to concerns about oil demand due to the global economic impacts of COVID-19. In addition, policy disputes in the first quarter 2020 between OPEC and Russia resulted in Saudi Arabia significantly discounting the price of its crude oil, as well as Saudi Arabia and Russia significantly increasing their oil supply. These actions led to significant weakness in oil prices and caused us to reduce our capital and operating budgets as well as slow our development plan. In addition, the potential spread of the virus into our workforce and the workforces of our counterparties could continue to have an adverse impact on our operations.

The total magnitude and duration of potential social, economic and labor instability as a direct result of COVID-19 cannot be estimated at this time. Should any of these potential impacts continue for an extended period of time, it will have a negative impact on the demand for our oil and natural gas products and have an adverse effect on our financial position and results of operations. The COVID-19 pandemic had an adverse effect on our business results in 2020. To the extent the COVID-19 pandemic adversely affects our business and financial results, it may also have the effect of heightening many of the other risks described in this “Risk Factors” section, such as those relating to our indebtedness, our need to generate sufficient cash flows to service our indebtedness and our ability to comply with the covenants contained in the agreements that govern our indebtedness.

Due to safety concerns related to the COVID-19 pandemic, many of our employees are working remotely for an indefinite time period, which may result in increased exposure to cyber and other operational risks.

Lack of availability of refining, gas processing, storage, gathering or transportation capacity will likely impact results of operations. The lack of availability of satisfactory oil, gas and NGL gathering and transportation, including trucks, railways and pipelines, gas processing, storage or refining capacity may hinder QEP's access to oil, gas and NGL markets or delay production from its wells. QEP's ability to market its production depends in substantial part on the availability, proximity and capacity of gathering, transportation, gas processing facilities, storage or refineries owned and operated by third parties. Although QEP has some contractual control over the transportation of its production through firm transportation and gas processing arrangements, third-party systems may be temporarily unavailable due to market conditions, mechanical failures, accidents, lack of contracted capacity on such systems or other reasons such as temporary suspension of service due to legal challenges (such as the pending litigation regarding the Dakota Access Pipeline, a major pipeline running out of the Williston Basin) and/or the pipeline’s failure to comply with applicable laws and regulations. If gathering, transportation, gas processing or storage facilities do not exist near producing wells; if gathering, transportation, gas processing, storage or refining capacity is limited; or if gathering, transportation, gas processing or refining capacity is unexpectedly disrupted, completion activity could be delayed, sales could be reduced, gas flaring and transportation costs could increase, or production could be shut-in, each of which could reduce profitability. The curtailments arising from these circumstances may last from a few days to several months, and in many cases, QEP is provided with limited, if any, notice as to when these circumstances will arise and their duration. Furthermore, if QEP were required to shut-in wells, it might also be obligated to pay certain demand charges for gathering and processing services, as well as shut-in royalties to certain mineral interest owners in order to maintain its leases; or depending on the specific lease provisions, some leases could terminate. In addition, rail accidents involving crude oil carriers have resulted in regulations, and may result in additional regulations, on transportation of oil by railway. QEP might be required to install or contract for additional treating or processing equipment for transport of crude oil by rail, which could increase costs. Federal and state regulation of oil and gas production and transportation, tax and energy policies, changes in supply and demand, transportation pressures, damage to or destruction of transportation facilities and general economic conditions could also adversely affect QEP's ability to transport oil and gas.

Lower oil, gas and NGL prices or negative adjustments to oil, gas and NGL reserves may result in significant impairment charges. Lower commodity prices may not only decrease QEP's revenues, operating income and cash flows but also may reduce the amount of oil, gas and NGL that QEP can produce economically. GAAP requires QEP to write down, as a non-cash charge to earnings, the carrying value of its oil and gas properties in the event QEP has impairments. QEP performs impairment tests on its assets whenever events or changes in circumstances warrant a review of its assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of its assets, the carrying value may not be recoverable, and, therefore, a write-down may be required. During the year ended December 31, 2020, the Company recorded unproved property impairment charges of $8.7 million related to anticipated leasehold expirations. During the year ended December 31, 2019, there were no impairments on its oil and gas related properties. During the year ended December 31, 2018, QEP recorded impairment charges of $1,524.6 million on its proved properties and $36.3 million on its unproved properties. Refer to Part I, Item 8, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for more information.

If forward oil prices decline from December 31, 2020 levels or we experience negative changes to the estimated reserve quantities, we have proved and unproved properties at risk for impairment. The actual amount of impairment incurred, if any, for these properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.

The Company may not be able to economically find and develop new reserves. The Company's liquidity and profitability depends not only on prevailing prices for oil, gas and NGL, but also on its ability to find, develop and acquire oil and gas reserves that are economically recoverable. Producing oil and gas reservoirs are generally characterized by declining production rates that vary depending on reservoir characteristics. Because oil and gas production volumes from unconventional wells typically experience relatively steep declines in the first year of operation and continue to decline over the economic life of the well, QEP must continue to invest significant capital to find, develop and acquire oil and gas reserves to replace those depleted by production. Failure to find or acquire additional reserves would cause reserves and production to decline materially from their current levels.

Oil and gas reserve estimates are imprecise, may prove to be inaccurate, and are subject to revision. Any significant inaccuracies in QEP's reserve estimates or underlying assumptions may negatively affect the quantities and present value of QEP's reserves. QEP's proved oil and gas reserve estimates are prepared annually by independent reservoir engineering consultants. Oil and gas reserve estimates are subject to numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and timing of development expenditures. The accuracy of these estimates depends on the quality of available data and on engineering, geological and geophysical interpretation and judgment. Reserve estimates are imprecise and will change as more information becomes available. Estimates of economically recoverable reserves and future net cash flows prepared by different engineers or by the same engineers at different times may vary significantly. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimation process involves economic assumptions relating to commodity prices, operating costs, severance and other taxes, capital expenditures and remediation costs. Actual results most likely will vary from the estimates. Any significant variance from these assumptions could affect the recoverable quantities of reserves attributable to any particular property, the classifications of reserves, the estimated future net cash flows from proved reserves and the present value of those reserves.

Investors should not assume that QEP's presentation of the Standardized Measure of Discounted Future Net Cash Flows relating to Proved Reserves in this Annual Report on Form 10-K is reflective of the current market value of the estimated oil and gas reserves. In accordance with SEC disclosure rules, the estimated discounted future net cash flows from QEP's proved reserves are based on the first-of-the-month prior 12-month average prices and current costs on the date of the estimate, holding the prices and costs constant throughout the life of the properties and using a discount factor of 10% per year. QEP's cost estimates do not include any future costs related to proposed climate change regulations. Actual future production, prices and costs may differ materially from those used in the current estimate, and future determinations of the Standardized Measure of Discounted Future Net Cash Flows using similarly determined prices and costs may be significantly different from the current estimate. Therefore, reserve quantities may change when actual prices increase or decrease. In addition, the 10% discount factor QEP uses when calculating discounted future net cash flows in accordance with SEC disclosure rules, may not be the most appropriate discount factor that is based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general.

In addition, realization or recognition of proved undeveloped reserves will depend on QEP's development schedule and plans. A change in future development plans for proved undeveloped reserves could cause the discontinuation of the classification of those reserves as proved. See Items 1 and 2. Business and Properties – Proved Reserves in this Annual Report on Form 10-K.

QEP may be required to write down its proved undeveloped reserve estimates if it is unable to convert those reserves into proved developed reserves within five years. SEC rules require that, subject to limited exceptions, proved undeveloped (PUD) reserves may only be classified as proved reserves if they are from locations scheduled to be drilled within five years after the date of booking. Recovery of PUD reserves requires the expenditure of significant capital and successful drilling operations. QEP may be required to write down its PUD reserves if it is not successful in drilling PUD wells within the required five-year time frame. During 2020 and 2019, QEP removed 16.9 MMboe and 25.8 MMboe, respectively, of PUD reserves that were no longer in the 2020 and 2019 forecasted capital expenditure plans, respectively, and would not be drilled and completed within five years of the initial date of booking of the reserves. The majority of the 2020 PUD write-downs were due to the Company's decision to reduce completion activity and suspend the refracturing program in the Williston Basin in 2020 in light of the market conditions and continued focus on Free Cash Flow generation. There is no assurance that we may not change our development plan again in the future, resulting in further write-downs. At December 31, 2020, approximately 55% of QEP's estimated proved reserves were PUD reserves. These reserve estimates reflect the Company's plans to make significant capital expenditures to convert its PUDs into proved developed reserves, requiring an estimated $1.6 billion during the five years ending December 31, 2025. The estimated development costs may not be accurate; timing to incur such costs may change; development may not occur as scheduled; and results may not be as estimated.

Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations. Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether producible hydrocarbons are, in fact, present in those structures in economic quantities. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

QEP faces significant competition and certain of its competitors have resources in excess of QEP's available resources. QEP operates in the highly competitive areas of oil and gas exploration, acquisition and production. QEP faces competition from:

- large multi-national, integrated oil companies;
- U.S. independent oil and gas companies;
- service companies engaging in oil and gas exploration and production activities; and
- private investing in oil and gas assets.

QEP faces competition in a number of areas such as:

- acquiring desirable producing properties or new leases for future exploration;
- acquiring or increasing access to gathering, processing and transportation services and capacity;
- marketing its oil, gas and NGL production;
- obtaining the equipment and expertise necessary to operate and develop properties; and
- attracting and retaining employees with certain critical skills.

Certain of QEP's competitors have financial and other resources in excess of those available to QEP. Such companies may be able to pay more for oil and gas properties and exploratory prospects and to define, evaluate, bid for and purchase a greater number of properties and prospects than QEP's financial or human resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than QEP is able to offer. This highly competitive environment could have an adverse impact on QEP's ability to execute its strategy, QEP's financial condition and its results of operations.

Shortages of qualified personnel and/or oilfield equipment and services as well as QEP's inability to retain or motivate key personnel or transfer knowledge from retiring personnel could negatively impact results of operations. QEP's performance largely depends on the talents and efforts of highly skilled individuals. The oil and gas industry has long suffered a skills shortage, recognized by many to be a threat to future growth. This skills shortage has been exacerbated by depressed oil and gas prices over the past several years and the resulting loss of skilled workers through layoffs in the oil and gas industry during these years. The demand for and availability of qualified and experienced personnel to drill wells and conduct field operations, in addition to geologists, geophysicists, engineers, landmen and other professionals in the oil and gas industry, will create challenges for QEP and its competitors and may cause periodic and problematic personnel shortages. In periods of high commodity prices, there have also been regional shortages of drilling rigs and other equipment. Any cost increases could impact profit margin, cash flow and operating results or restrict QEP's ability to drill wells and conduct operations.

In connection with the successful completion of the Uinta Basin and Haynesville divestitures, as well as its initiative to significantly reduce its general and administrative expense to ensure that it is competitive with industry peers, QEP experienced a reduction in headcount in 2018 and 2019. Additionally, in 2019, QEP's President and Chief Executive Officer, its Executive Vice President of Operations, and its Executive Vice President and Chief Financial Officer, each of whom had long tenure with the Company, departed the Company.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application. Our operations involve utilizing some of the latest drilling and completion techniques. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

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

Risks that we face while completing our wells include, but are not limited to, our inability to:

- fracture stimulate the planned number of stages;
- run tools the entire length of the wellbore during completion operations;
- successfully clean out the wellbore after completion of the final fracture stimulation stage;
- prevent unintentional communication with other wells; and
- design and maintain efficient artificial lift throughout the life of the well.

QEP began testing the restimulation, or refracturing, of wells in the Williston Basin during 2017. Refracturing an existing well is technically more challenging than fracturing a new well and may result in the loss of the existing producing well.

If our drilling and completion activities do not meet our anticipated results or we are unable to execute our drilling and completion program because of capital constraints, lease expirations, limited access to gathering systems, limited takeaway capacity and/or declines in crude oil and natural gas prices or unconventional wells are not achieving production expectations, the return on our investment for certain projects may not be as attractive as we anticipate. Further, as a result of any of these developments, we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Multi-well pad drilling may result in volatility in QEP operating results and delay conversion of PUD reserves. QEP utilizes multi-well pad drilling where practical. For example, in the Permian Basin, QEP utilizes "tank-style" development, in which we drill and complete all wells in a given "tank" before any individual well is turned to production. In the Williston Basin, QEP drills multiple wells from a single pad. Wells drilled on a pad are not brought into production until all wells on the pad are drilled and cased and the drilling rig is moved from the location. In addition, existing wells that offset newly drilled wells may be temporarily shut-in during the drilling and completion process. As a result, multi-well pad drilling delays the completion of wells, the commencement of production from new wells, and may negatively affect the production from existing offset wells, all of which may cause volatility in QEP's operating results from period to period. This may lead to additional volatility in QEP's operating results. Finally, delays in completion of wells may impact planned conversion of PUD reserves to proved developed.

Certain of QEP's leaseholds are subject to lease and other agreements that will expire over the next several years unless production in paying quantities is established and maintained on the acreage or on units containing the acreage, certain drilling obligations are satisfied, or the leases are otherwise renewed or extended. Leases on oil and gas properties typically have a primary term of three to five years after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established or the lease is renewed or extended. Other agreements relating to leasehold may obligate QEP to meet certain drilling obligations to maintain leases in effect. If a lease expires or is not renewed before expiration, or if QEP does not meet contractual drilling obligations, QEP will lose its right to develop the related reserves. While QEP seeks to actively manage its leasehold inventory by drilling sufficient wells and otherwise meeting drilling obligations necessary to hold the leases that it believes are material to its operations, QEP's drilling plans are subject to change based upon various factors, including drilling results, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Under the terms of certain of our leases and the laws in the states in which we operate, production from our wells must be maintained in paying quantities. If we fail to maintain certain levels of production or otherwise fail to comply with the terms of our leases (e.g. paying royalties in a timely and correct manner), it is possible for us to lose our leases.

QEP's identified potential well locations are scheduled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, QEP may not be able to raise the substantial amount of capital that would be necessary to drill its potential well locations. QEP has identified and scheduled well locations to build its multi-year development plan for its existing leaseholds. These well locations represent a significant part of QEP's future development strategy. QEP's ability to drill and develop these locations is impacted by a number of uncertainties, including the ongoing review and analysis of geologic and engineering data, oil and gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, potential interference between infill and existing wells, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water and water disposal and recycling facilities, regulatory approvals and other factors. Because of these factors, QEP does not know if the potential well locations it has identified will be drilled or if QEP will be able to produce oil and gas from these or any other potential well locations. In addition, any drilling activities QEP is able to conduct on these potential locations may not be successful or result in QEP's ability to add additional proved reserves to its overall proved reserves or may result in a downward revision of its estimated proved reserves, which could have a material adverse effect on QEP's future business and results of operations.

Renegotiation of gathering, processing and transportation agreements may result in higher costs and/or delays in selling production. Substantially all of QEP's production depends on the availability of gathering, transportation, gas processing, or storage facilities owned and operated by midstream service providers under agreements which expire periodically. If QEP agrees to renew or extend its midstream agreements, the costs QEP pays for midstream services may increase. If QEP and any of its midstream service providers cannot agree on revised terms to these agreements, the midstream service providers may assert that continued performance of their obligations under these contracts is uneconomic and attempt to terminate or alter the agreements, which could hinder QEP's access to oil, gas and NGL markets, increase costs and/or delay completion of or production from its wells. Disputes over termination or changes to such agreements could result in arbitration or litigation, causing uncertainty about the status of the agreements and further delays.

QEP has limited control over the activities on properties it does not operate, which could adversely affect our production, revenues and returns on capital. As of December 31, 2020, QEP operates 97% of its net productive oil and natural gas wells. Other companies operate some of the properties in which QEP has an interest. QEP has limited ability to influence or control the operation or future development of these non-operated properties, including compliance with environmental, safety and other regulations, or the amount or timing of capital expenditures that QEP is required to fund with respect to them. The failure of an operator of QEP's wells to adequately perform operations, an operator's breach of the applicable agreements with QEP or an operator's failure to act in ways that are in QEP's best interest could reduce QEP's production and revenues. QEP's dependence on the operator and other working interest owners to complete these projects and QEP's limited ability to influence or control the operation and future development of these properties could adversely affect the realization of QEP's targeted returns on capital in drilling or acquisition activities, lead to unexpected future costs, or adversely affect the timing of activities. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's decisions with respect to the timing and amount of capital expenditures, the period of time over which the operator seeks to generate a return on capital expenditures, inclusion of other participants in drilling wells, and the use of technology, as well as the operator's expertise and financial resources and the operator's relative interest in the field. Operators may also opt to decrease operational activities following a significant decline in, or a sustained period of low, oil or natural gas prices. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance. Accordingly, while we use reasonable efforts to cause the operator to act in a prudent manner, we are limited in our ability to do so.

QEP faces various risks associated with the trend toward increased opposition to oil and gas exploration and development activities. Opposition to oil and gas drilling and development activity has been growing globally and is particularly pronounced in the United States. Companies in the oil and gas industry, such as QEP, are often the target of activist efforts from both individuals and environmental nongovernmental organizations (ENGOs) regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to federal and state government lands and delay or cancel certain projects such as the development of oil or gas shale plays. For example, ENGOs and other environmental activists continue to advocate for increased regulation of shale drilling in the U.S., even in jurisdictions that are among the most stringent in their regulation of the industry. Future activist efforts could result in the following:

- delay or denial of drilling and other necessary permits;
- shortening of lease terms or reduction in lease size;
- bans on hydraulic fracturing;
- bans on crude oil and natural gas exports;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- restrictions on flaring of natural gas;
- more stringent setback requirements from houses, schools, businesses and other improvements and landscape features;
- towns, cities, states and counties imposing bans on certain activities, including hydraulic fracturing;
- restrictions on the use of certain operating practices, such as hydraulic fracturing, or the disposition of related waste materials, such as hydraulic fracturing fluids and produced water;
- reduced access to water supplies or restrictions on produced water disposal;
- increased severance and/or other taxes;
- cyberattacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- disinvestment and other targeted activist shareholder campaigns;
- increased costs of doing business;
- reduction in demand for QEP's production;
- other adverse effects on QEP's ability to develop its properties and increase production;
- increased regulation of rail transportation of crude oil;
- opposition to the construction of new oil and gas pipelines;
- postponement of state and federal oil and gas lease sales; and
- delays in or challenges to issuance of federal and tribal oil and gas leases.

QEP may incur substantial costs associated with responding to these initiatives or complying with any resulting additional legal or regulatory requirements that are not adequately provided for, which could have a material adverse effect on its business, financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest. The existence of a material title deficiency can render a lease worthless. In the course of acquiring the rights to develop oil or natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment, subject to title verification. There is no certainty, however, that a lessor has valid title to their lease's oil and gas interests. In those cases, such leases are generally voided, and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Accordingly, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Failure to fund continued capital expenditures could adversely affect QEP's properties. QEP's exploration, development and acquisition activities require capital expenditures to achieve production and cash flows. Historically, QEP has funded its capital expenditures through a combination of cash flows from operations, its revolving credit facility, debt issuances, equity offerings and sales of assets. Future cash flows from operations are subject to a number of variables, such as the level of production from existing wells, prices of oil, gas and NGL, and QEP's success in finding, developing and producing new reserves. Our failure to fund capital expenditures may delay or prevent the development of our properties, which may adversely impact our ability to retain leaseholds that are held by production, increase lease expirations, and decrease production and reserves from our properties.

Our business could be negatively affected as a result of actions of activist shareholders, and such activism could impact the strategic direction of QEP and the trading value of our securities. Shareholders may from time to time attempt to effect changes, engage in proxy solicitations or advance shareholder proposals. Activist shareholders may make strategic proposals, suggestions or requested changes concerning our operations, strategy, management, assets or other matters. For example, in response to a January 2019 proposal from Elliott Management Corporation to acquire all shares of our common stock, our Board of Directors engaged in a comprehensive review of strategic alternatives and concluded that the best alternative for QEP's shareholders was to move forward as an independent company. Responding to additional actions by activist shareholders could be costly and time-consuming, disrupting our operations and diverting the attention of our management and employees. Such activities could interfere with our ability to execute our strategic plan or realize long-term value from our assets.

Risks Related to the Merger

Because the exchange ratio is fixed and because the market price of Diamondback common stock will fluctuate, QEP stockholders cannot be certain of the precise value of the Merger consideration they will receive in the Merger. If the Merger is completed, at the effective time of the Merger, each issued and outstanding eligible share of QEP common stock will be converted into the right to receive the Merger Consideration. The exchange ratio for the Merger Consideration is fixed at 0.050 of a share of Diamondback common stock for each share of QEP common stock and there will be no adjustment to the Merger Consideration for changes in the market price of Diamondback common stock or QEP common stock prior to the completion of the Merger.

If the Merger is completed, there will be a time lapse between the date of signing the Merger Agreement, the date on which our stockholders vote to approve the Merger and the date on which our stockholders entitled to receive the Merger Consideration actually receive the Merger Consideration. The market value of shares of Diamondback common stock will fluctuate, possibly materially, during and after these periods as a result of a variety of factors, including general market and economic conditions, changes in Diamondback's businesses, operations and prospects and regulatory considerations and any impact of the ongoing COVID-19 pandemic. Such factors are difficult to predict and in many cases may be beyond the control of Diamondback and us. The actual value of any Merger Consideration received by our stockholders at the completion of the Merger will depend on the market value of the shares of Diamondback common stock at that time. Consequently, at the time our stockholders decide whether to approve the Merger proposal, they will not know the actual market value of any Merger Consideration they will receive when the Merger is completed.

The Merger may not be completed and the Merger Agreement may be terminated in accordance with its terms. Failure to complete the Merger could negatively impact the price of shares of our common stock, as well as our future business and financial results. The Merger is subject to a number of conditions that must be satisfied, including the approval by our stockholders of the Merger Agreement, or, to the extent permitted by applicable law, waived, in each case prior to the completion of the Merger. These conditions to the completion of the Merger, some of which are beyond our control and the control of Diamondback, may not be satisfied or waived in a timely manner or at all, and, accordingly, the Merger may be delayed or may not be completed.

In addition, if the Merger is not completed by June 30, 2021, or, in certain instances, on or before September 30, 2021, either we or Diamondback may choose not to proceed with the Merger by terminating the Merger Agreement, and the parties can mutually decide to terminate the Merger Agreement at any time, before or after stockholder approval. Further, either we or Diamondback may elect to terminate the Merger agreement in certain other circumstances.

If the transactions contemplated by the Merger Agreement are not completed for any reason, our ongoing business, financial condition and financial results may be adversely affected. Without realizing any of the benefits of having completed the Merger, we will be subject to a number of risks, including the following:

- we will be required to pay our costs relating to the Merger, which are substantial, such as legal, accounting, financial advisory and printing fees, whether or not the Merger is completed;
- we may owe a termination fee of $17 million to Diamondback, as further described below;
- time and resources committed by our management to matters relating to the Merger could otherwise have been devoted to pursuing other beneficial opportunities;
- we may experience negative reactions from financial markets, including negative impacts on the price of our common stock, including to the extent that the current market price reflects a market assumption that the Merger will be completed;
- we may experience negative reactions from employees, customers or vendors; and
- since the Merger Agreement restricts the conduct of our business prior to completion of the Merger, we may not have been able to take certain actions during the pendency of the Merger that would have benefitted us as an independent company and the opportunity to take such actions may no longer be available.

If the Merger Agreement is terminated and our board seeks another Merger or business combination, we may not be able to find a party willing to offer equivalent or more attractive consideration than the consideration Diamondback has agreed to provide in the Merger. If the Merger Agreement is terminated under specified circumstances, we may be required to pay Diamondback a termination fee of $17 million. If the Merger Agreement is terminated because of a failure of our stockholders to approve the proposals required to complete the Merger, we may be required to reimburse Diamondback for any reasonable, documented, out-of-pocket expenses paid or incurred by Diamondback in connection with the Merger, in an amount not to exceed $7.5 million.

Our stockholders will have a reduced ownership and voting interest in the combined company after the Merger compared to their current ownership in QEP and will exercise less influence over the combined company's management. Currently, our stockholders have the right to vote in the election of our board and the power to approve or reject any matters requiring stockholder approval under Delaware law and our organizational documents. Upon completion of the Merger, each of our stockholders who receives shares of Diamondback common stock in the Merger will become a stockholder of Diamondback with a percentage ownership of Diamondback that is smaller than such stockholder's current percentage ownership of QEP. Even if all former QEP stockholders voted together on all matters presented to Diamondback stockholders from time to time, the former QEP stockholders would exercise significantly less influence over on the management and policies of Diamondback post-Merger than they now have on the management and policies of QEP.

If the Merger does not qualify as a "reorganization" under Section 368(a) of the Internal Revenue Code of 1986, as amended (Code), our stockholders may be subject to U.S. federal income tax upon the receipt of Diamondback common stock in the Merger. We and Diamondback intend for the Merger to be treated as a "reorganization" within the meaning of Section 368(a) of the Code for U.S. federal income tax purposes. However, it is not a condition to our obligation or Diamondback's obligation to complete the Merger that the Merger qualifies as a "reorganization." Moreover, neither we nor Diamondback intend to request any ruling from the Internal Revenue Service (the "IRS") regarding any matters relating to the Merger, and, consequently, there can be no assurance that the IRS will not assert, or that a court would not sustain, a position to the contrary to our and Diamondback's intended tax treatment. If the IRS were to challenge the "reorganization" status of the Merger successfully or the form or structure of the Merger was changed in a manner such that it did not qualify as a "reorganization," the tax consequences would differ from those currently intended, and holders of QEP common stock could be subject to U.S. federal income tax upon the receipt of Diamondback common stock in the merger.

We are subject to business uncertainties while the Merger is pending, which could adversely affect our business. Uncertainty about the effect of the Merger on employees, industry contacts and business partners may have an adverse effect on our business. These uncertainties may impair our ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter and could cause industry contacts, business partners and others that deal with us to seek to change their existing business relationships with us. Employee retention may be particularly challenging during the pendency of the Merger, as employees may experience uncertainty about their roles with Diamondback following the Merger. In addition, the Merger Agreement restricts us from entering into certain corporate transactions and taking other specified actions without the consent of Diamondback. These restrictions may prevent us from pursuing attractive business opportunities that may arise prior to the completion of the Merger.

The Merger Agreement limits our ability to pursue alternatives to the Merger, which may discourage certain other companies from making favorable alternative transaction proposals and, in specified circumstances, could require us to pay Diamondback a termination fee. The Merger Agreement contains provisions that may discourage a third party from submitting a competing proposal to us that might result in greater value to our stockholders than the Merger or, in the event that a third party competing proposal is made, a third party may propose to pay a lower per share price to acquire us than it might otherwise have proposed to pay. These provisions include generally prohibit us from soliciting or, subject to certain exceptions relating to the exercise of fiduciary duties by our board, entering into discussions with any third party regarding any competing proposal. Further, even if our board withholds, withdraws, qualifies or modifies its recommendation with respect to the Merger, unless the Merger Agreement has been terminated in accordance with its terms, we will still have an obligation to submit the Merger proposal to a vote of our stockholders. The Merger Agreement further provides that under specified circumstances, including after a change of recommendation by our board and a subsequent termination of the Merger agreement by Diamondback in accordance with its terms, we may be required to pay Diamondback a cash termination fee in the amount of $17 million.

Our directors and executive officers may have interests in the Merger that are different from, or in addition to, the interests of our stockholders. Our directors and executive officers may have interests in the Merger that are different from, or in addition to, the interests of our stockholders generally. These interests include, among others, the treatment of outstanding equity and equity-based awards pursuant to the Merger Agreement, potential severance and other benefits upon a qualifying termination in connection with the Merger, and rights to ongoing indemnification and insurance coverage.

We will incur significant transaction and merger-related costs in connection with the Merger, which may be in excess of those anticipated. We have incurred and expect to continue to incur a number of non-recurring costs associated with negotiating and completing the Merger, combining the operations of the two companies and achieving desired synergies. These fees and costs have been, and will continue to be, substantial. The substantial majority of non-recurring expenses will consist of transaction costs related to the Merger and include, among others, employee retention costs, fees paid to financial, legal and accounting advisors, severance and benefit costs, and filing fees.

We will also incur transaction fees and costs related to the integration of the companies, which may be substantial. Moreover, we may incur additional unanticipated expenses in connection with the Merger and the integration, including costs associated with any stockholder litigation related to the Merger. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow Diamondback and QEP to offset integration-related costs over time, this net benefit may not be achieved in the near term, or at all.

Completion of the Merger may trigger change in control or other provisions in certain agreements to which we or our subsidiaries are a party. The completion of the Merger may trigger change in control or other provisions in certain agreements to which we or our subsidiaries are a party. If we are unable to negotiate waivers of those provisions, the counterparties may exercise their rights and remedies under such agreements, potentially terminating the agreement or seeking monetary damages. Additionally, even if we are able to negotiate waivers, the counterparties may require a fee for such waivers or seek to renegotiate the agreements on terms less favorable to the combined company.

We may be targets of securities class action and derivative lawsuits that could result in substantial costs and may delay or prevent the Merger from being completed. Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into Merger Agreements. Even if the lawsuits are 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. Any such lawsuit could also seek, among other things, injunctive relief or other equitable relief, including a request to rescind parts of the Merger Agreement already implemented or to otherwise enjoin us and Diamondback from consummating the Merger. If a plaintiff is successful in obtaining an injunction prohibiting completion of the Merger, then that injunction may delay or prevent the Merger from being completed, which may adversely affect our business, financial position and results of operation.

One of the conditions to the closing of the Merger is that no injunction by any court or other tribunal of competent jurisdiction has been entered and continues to be in effect and no law has been adopted or is effective, in either case, that prohibits or makes illegal the consummation of the Merger. Consequently, if a lawsuit is filed and a plaintiff is successful in obtaining an injunction prohibiting consummation of the Merger, then that injunction may delay or prevent the Merger from being completed within the expected timeframe or at all, which may adversely affect our business, financial position, and results of operations.

Shares of Diamondback common stock received by our stockholders as a result of the Merger will have different rights from shares of our common stock. Upon completion of the Merger, our stockholders will no longer be stockholders of QEP, and our stockholders who receive the Merger consideration will become Diamondback stockholders, and their rights as Diamondback stockholders will be governed by the terms of Diamondback's charter and bylaws. There will be important differences between the current rights of our stockholders and the rights to which such stockholders will be entitled as Diamondback stockholders.

Risks Related to the Company

QEP's certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if an acquisition or merger may be in QEP shareholders' best interests. QEP's certificate of incorporation authorizes its Board of Directors to issue preferred stock without shareholder approval. If QEP's Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire QEP. In addition, some provisions of QEP's certificate of incorporation and bylaws could make it more difficult for a third party to acquire control of QEP, even if the transaction would be beneficial to QEP shareholders, including:

- authorization for the issuance of "blank check" preferred stock that our board of directors could issue to increase the number of outstanding shares to discourage a takeover attempt;
- advance notice requirements for shareholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of shareholders;
- the inability of QEP shareholders who own less than 25% or more of outstanding shares of QEP's common stock to call special meetings; and
- the inability of QEP shareholders to act by written consent.

In addition, Delaware law imposes restrictions on mergers and other business combinations between QEP and any holder of 15% or more of QEP's outstanding common stock.

Any provision of our certificate of incorporation or bylaws or Delaware law that has the effect of delaying or deterring a change in control could limit the opportunity for our stockholders to receive a premium for their shares of our common stock and could also affect the price that some investors are willing to pay for our common stock.

If we cannot meet the continued listing requirements of the NYSE, the NYSE may delist our common stock. The New York Stock Exchange (NYSE) has several listing requirements set forth in the NYSE Listed Company Manual. For example, Section 802.01C of the NYSE Listed Company Manual requires that a company's common stock trade at a minimum average closing price of $1.00 per share over a consecutive 30-trading day period. Pursuant to the rules of the NYSE, companies who fail to maintain this listing requirement have a six month period in which to regain compliance or be delisted. In addition, our common stock could also be delisted if (i) our average market capitalization over a consecutive 30 trading-day period is less than $15 million, or (ii) our common stock trades at an "abnormally low" price, which the NYSE has historically viewed to be $0.16 per share. If either event were to occur, we would not have an opportunity to cure the deficiency, and, as a result, our common stock would be suspended from trading on the NYSE immediately, and the NYSE would begin the process to delist our common stock, subject to our right to appeal under NYSE rules. There is no assurance that any appeal we undertake in these or other circumstances would be successful, nor is there any assurance that we will continue to comply with the other NYSE continued listing standards.

Failure to maintain our NYSE listing could negatively impact us and our stockholders by reducing the willingness of investors to hold our common stock because of the resulting decreased price, liquidity and trading of our common stock, limited availability of price quotations, and reduced news and analyst coverage. These developments may also require brokers trading in our common stock to adhere to more stringent rules and may limit our ability to raise capital by issuing additional shares in the future. Delisting may adversely impact the perception of our financial condition and cause reputational harm with investors and parties conducting business with us. In addition, the perceived decreased value of employee equity incentive awards may reduce their effectiveness in encouraging performance and retention.

There may be future dilution of QEP's common stock, which could adversely affect the market price of QEP's common stock. QEP is not restricted from issuing additional shares of its common stock. In the future, QEP may issue shares of its common stock to raise cash for future capital expenditures, acquisitions or for general corporate purposes. QEP may also acquire interests in other companies by using a combination of cash and its common stock or just its common stock. QEP may also issue securities convertible into, exchangeable for or that represent the right to receive its common stock. Lastly, QEP currently issues restricted share awards, restricted share units and performance share units to its employees and directors as part of their compensation. Any of these events will dilute QEP shareholders' ownership interest in QEP and may reduce QEP's earnings per share and have an adverse effect on the price of QEP's common stock. In addition, sales of a substantial amount of QEP's common stock in the public market, or the perception that these sales may occur, could reduce the market price of QEP's common stock.

Substantially all of our producing properties and operations are located in the Permian and Williston basins, making us vulnerable to risks associated with operating in a limited number of basins. As a result of our lack of diversification in asset type and our limited geographic diversification, any delays or interruptions of production caused by such factors as governmental regulation; density and proration requirements of state regulators; transportation capacity constraints; curtailment of production or interruption of transportation; price fluctuations; natural disasters; or shutdowns of the pipelines connecting our production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian and Williston basins, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of 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. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

QEP may be unable to make acquisitions, successfully integrate acquired businesses and/or assets, or adjust to the effects of divestitures, causing a disruption to its business. One aspect of QEP's business strategy calls for acquisitions of businesses and assets that complement or expand QEP's operations. QEP cannot provide assurance that it will be able to identify additional acquisition opportunities. Even if QEP does identify additional acquisition opportunities, it may not be able to complete the acquisitions due to capital constraints. Any acquisition of a business or assets involves potential risks, including, among others:

- incorrect estimates or assumptions about reserves, exploration potential or potential drilling locations;
- incorrect assumptions regarding future revenues, including future commodity prices and differentials, or regarding future development and operating costs;
- difficulty integrating the operations, systems, management and other personnel and technology of the acquired business or assets with QEP's own;
- the assumption of unidentified or unforeseeable liabilities, resulting in a loss of value;
- the inability to hire, train or retain qualified personnel to manage and operate QEP's growing business and assets; or
- a decrease in QEP's liquidity to the extent it uses a significant portion of its available cash or borrowing capacity to finance acquisitions or operations of the acquired properties.

Organizational modifications due to acquisitions, divestitures or other strategic changes can alter the risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; harm QEP's strategy; and adversely affect results of operations. Even if these challenges can be dealt with successfully, the anticipated benefits of any acquisition, divestiture or other strategic change may not be realized.

In addition, QEP's credit agreement and the indentures governing QEP's senior notes impose certain limitations on QEP's ability to enter into mergers, business combinations and divestiture transactions. QEP's credit agreement also limits QEP's ability to incur certain indebtedness, which could limit QEP's ability to engage in acquisitions.

QEP may be unable to divest assets on financially attractive terms, resulting in reduced cash proceeds. Over the past several years, QEP has relied on proceeds from asset divestitures to help fund acquisitions, make capital expenditures and to repay debt. QEP's success in divesting assets depends, in part, upon QEP's ability to identify suitable buyers or joint venture partners; assess potential transaction terms; negotiate agreements; and, if applicable, obtain required approvals. Various factors could materially affect QEP's ability to dispose of assets on terms acceptable to QEP. Such factors include, but are not limited to: current and forecasted commodity prices; current laws, regulations and permitting processes impacting oil and gas operations in the areas where the assets are located; covenants under QEP's credit agreement; tax impacts; willingness of the purchaser to assume certain liabilities such as asset retirement obligations and firm transportation contracts; QEP's willingness to indemnify buyers for certain matters; and other factors.

In addition, QEP's credit agreement contains limitations on the amount of assets that it is permitted to divest each year. If QEP seeks to sell more assets than is permitted under the credit agreement and is unable to receive waivers of such restrictions, then it may be unable to divest these assets.

QEP is required to pay fees to some of its midstream service providers based on minimum volumes regardless of actual volume throughput. QEP has contracts with some third-party service providers for gathering, processing and transportation services with minimum volume delivery commitments under which QEP is obligated to pay certain fees on minimum volumes regardless of actual volume throughput. As of December 31, 2020, QEP's aggregate long-term contractual obligation under these agreements was $70.9 million. These fees could be significant and may have a material adverse effect on QEP's results of operations.

QEP is partially dependent on its revolving credit facility and continued access to capital markets to successfully execute its operating strategies. If QEP is unable to make capital expenditures or acquisitions because it is unable to obtain capital or financing on satisfactory terms, QEP may experience a decline in its oil and gas production rates and reserves. QEP is partially dependent on external capital sources to provide financing for certain projects. The availability and cost of these capital sources is cyclical, and these capital sources may not remain available, or QEP may not be able to obtain financing at a reasonable cost in the future. QEP is largely dependent on its credit facility to successfully execute its commodity price and interest rate risk mitigation strategies. If QEP is unable to successfully extend the maturity date or amend the terms of its credit facility, it may not be able to obtain adequate access to the necessary credit from its lending group to enter into its preferred amount of derivative contracts with respect to its forecasted annual production. Over the last few years, conditions in the global capital markets have been volatile, making terms for certain types of financing difficult to predict, and in certain cases, resulting in certain types of financing being unavailable. If QEP's revenues decline as a result of lower oil, gas or NGL prices, operating difficulties, declines in production or for any other reason, QEP may have limited ability to obtain the capital necessary to sustain its operations at current levels. In the past, QEP has utilized cash and its revolving credit facility to meet short-term funding needs. At year end 2020, QEP had no outstanding borrowings under its revolving credit facility. QEP's failure to obtain additional financing could result in a curtailment of its operations relating to exploration and development of its prospects, which in turn could lead to a possible reduction in QEP's oil or gas production, reserves and revenues, not having sufficient liquidity to meet future financial obligations and could negatively impact QEP's results of operations.

QEP's debt and other financial commitments may limit its financial and operating flexibility. QEP's total debt was approximately $1.6 billion at December 31, 2020. QEP also has various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services, products and properties. QEP's financial commitments could have important consequences to its business, including, but not limited to, limiting QEP's ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, to pay dividends, to repurchase shares of its common stock, or to otherwise realize the value of its assets and opportunities fully because of the need to dedicate a substantial portion of its cash flows from operations and proceeds from the divestiture of its assets to payments on its debt or to comply with any restrictive terms of its debt. QEP may be at a competitive disadvantage as compared to similar companies that have less debt. Higher levels of debt may make QEP more vulnerable to general adverse economic and industry conditions. Additionally, the agreement governing QEP's revolving credit facility and the indentures governing QEP's senior notes contain a number of covenants that impose constraints on the Company, including requirements to comply with certain financial covenants and restrictions on QEP's ability to dispose of assets, make certain investments, incur liens and additional debt, and engage in transactions with affiliates. If commodity prices decline and QEP reduces its level of capital spending and production declines or QEP incurs additional impairment expense or the value of the Company's proved reserves declines, the Company may not be able to incur additional indebtedness, may need to repay outstanding indebtedness and may not be in compliance with the financial covenants in its credit agreement in the future. Refer to Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II of this Annual Report on Form 10-K and Note 9 – Debt, in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding the financial covenants and our revolving credit agreement.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital. Downgrades of QEP's credit rating may make it more difficult or expensive for QEP to raise capital from financial institutions or other sources and could require QEP to provide financial assurance of its performance under certain contractual arrangements and derivative agreements. Refer to Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations in Part II of this Annual Report on Form 10-K and Note 9 – Debt, in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding the financial covenants and our revolving credit agreement.

QEP's use of derivative instruments to manage exposure to uncertain prices could result in financial losses or reduce its income. QEP uses commodity price derivative arrangements to reduce exposure to the volatility of oil, gas and NGL prices, and to protect cash flow and returns on capital from downward commodity price movements. QEP's derivative transactions are limited in duration, usually for periods of one to two years. QEP's derivatives portfolio may be inadequate to protect it from prolonged declines in the price of oil or natural gas. To the extent the Company enters into commodity derivative transactions, it may forgo some or all of the benefits of commodity price increases. Furthermore, QEP's use of derivative instruments through which it attempts to reduce the economic risk of its participation in commodity markets could result in increased volatility of QEP's reported results. Changes in the fair values (gains and losses) of derivatives are recorded in QEP's income, which creates the risk of volatility in earnings even if no economic impact to QEP has occurred during the applicable period. QEP has incurred significant unrealized and realized gains and losses in prior periods and may continue to incur these types of gains and losses in the future.

QEP is exposed to counterparty credit risk as a result of QEP's receivables and commodity derivative transactions. QEP has significant credit exposure to outstanding accounts receivable from purchasers of its production and joint working interest owners. This counterparty credit risk is heightened during times of economic uncertainty, tight credit markets and low commodity prices. Because QEP is the operator of a majority of its production and major development projects, QEP pays joint venture expenses and in some cases makes cash calls on its non-operating partners for their respective shares of joint venture costs. These projects are capital intensive, and, in some cases, a non-operating partner may experience a delay in obtaining financing for its share of the joint venture costs. Counterparty liquidity problems could result in a delay or collection issues in QEP receiving proceeds from commodity sales or reimbursement of joint venture costs. Credit enhancements, such as parental guarantees, letters of credit or prepayments, have been obtained from some but not all counterparties. Nonperformance by a trade creditor or joint venture partner could result in financial losses. In addition, QEP's commodity derivative transactions expose it to risk of financial loss if the counterparty fails to perform under a contract. During periods of falling commodity prices, QEP's commodity derivative receivable positions increase, which increases its counterparty credit exposure. QEP monitors creditworthiness of its trade creditors, joint venture partners, derivative counterparties and financial institutions on an ongoing basis. However, if one of them were to experience a sudden change in liquidity, it could impair such a party's ability to perform under the terms of QEP's contracts. QEP is unable to predict sudden changes in creditworthiness or ability of these parties to perform and could incur significant financial losses.

QEP is involved in legal proceedings that could result in substantial liabilities and materially and adversely impact the Company's financial condition. Like many oil and gas companies, the Company is involved in various legal proceedings, including threatened claims, such as title, royalty, and contractual disputes. The cost to settle legal proceedings (pending or threatened) or satisfy any resulting judgment against the Company in such proceedings could result in a substantial liability or the loss of interests, which could materially and adversely impact the Company's cash flows, operating results and financial condition. Judgments and estimates to determine accruals or the range of reasonably possible loss related to legal proceedings could change from one period to the next, and such changes could be material. Current accruals may be insufficient. Legal proceedings could result in negative publicity about the Company. In addition, legal proceedings distract management and other personnel from their primary responsibilities.

The Company's ability to declare and pay dividends is subject to certain considerations. Dividends are authorized and determined by the Company's Board of Directors in its sole discretion. Decisions regarding the payment of dividends are subject to a number of considerations, including:

- cash available for distribution;
- the Company's results of operations and anticipated future results of operations;
- the Company's financial condition, especially in relation to the anticipated future capital needs;
- the level of cash reserves the Company may establish to fund future capital expenditures;
- the Company's stock price; and
- other factors the board of directors deems relevant.

The Company can provide no assurance that it will pay dividends in the future.

Regulatory Risks

QEP is subject to complex federal, state, tribal, local and other laws and regulations that could adversely affect its cost of doing business and recording of proved reserves. QEP's operations are subject to extensive federal, state, tribal and local tax, energy, environmental, health and safety laws and regulations. The failure to comply with applicable laws and regulations can result in substantial penalties and may threaten the Company's authorization to operate.

Environmental laws and regulations are complex, change frequently and have tended to become more onerous over time. This regulatory burden on the Company's operations increases its cost of doing business and, consequently, affects its profitability. In addition to the costs of compliance, substantial costs may be incurred to take corrective actions at both owned and previously owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of QEP's business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time, but now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, other damages, or injunctions that could limit the scope of QEP's planned operations.

Moreover, uncertainty about the future course of regulation exists because of the recent change in the U.S. presidential administration. In January 2021, the current administration issued an executive order directing all federal agencies to review and take action to address any federal regulations, orders, guidance documents, policies and any similar agency actions promulgated during the prior administration that may be inconsistent with the administration’s policies. As a result, it is unclear the degree to which certain recent regulatory developments may be modified or rescinded. The executive order also established an Interagency Working Group on the Social Cost of Greenhouse Gases (Working Group), which is called on to, among other things, develop methodologies for calculating the “social cost of carbon,” “social cost of nitrous oxide” and “social cost of methane.” Recommendations from the Working Group are due beginning June 1, 2021, and final recommendations no later than January 2022. Further regulation of air emissions, as well as uncertainty regarding the future course of regulation, could eventually reduce the demand for oil and natural gas. Also in January 2021, the current administration issued the 2021 Climate Change Executive Order. Among other things, the 2021 Climate Change Executive Order directed the Secretary of the Interior to pause new oil and natural gas leasing on public lands or in offshore waters pending completion of a comprehensive review of the federal permitting and leasing practices, consider whether to adjust royalties associated with coal, oil, and gas resources extracted from public lands and offshore waters, or take other appropriate action, to account for corresponding climate costs. The 2021 Climate Change Executive Order also directs the federal government to identify "fossil fuel subsidies" to take steps to ensure that, to the extent consistent with applicable law, federal funding is not directly subsidizing fossil fuels. Legal challenges to the suspension have already been filed and are currently pending.

QEP complies with numerous environmental regulations. Refer to Items 1 & 2 of Part I Government Regulations of this Annual Report on Form 10-K for additional detail on these regulations.

Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations. Wells in the Williston Basin of North Dakota and the Permian Basin of Texas, where QEP has significant operations, produce natural gas as well as crude oil. Constraints in third party gas gathering and processing systems in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In 2014, the NDI Commission, North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Williston Basin. The NDI Commission requires operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties may be imposed on certain wells that cannot meet the capture goals. It is possible that other states in which QEP operates, including Texas, will require gas capture plans or otherwise institute new regulatory requirements in the future to reduce flaring.

In July and October 2020, after several years of litigation, federal courts struck down both the BLM’s 2016 Waste Prevention Rule and its 2018 Revised Waste Prevention Rule. The effect of these orders combined is to essentially reinstate the previous rule, Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases: Royalty or Compensation for Oil and Gas Lost (NTL-4A). However, future gas capture requirements and other regulatory requirements, in North Dakota or our other locations, could increase our operational costs and restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows. If our interpretation of the applicable regulations is incorrect, or if we receive a non-appealable order to pay royalty on past and future flared volumes in North Dakota, such royalty payments could materially and adversely affect our financial condition and cash flows.

The 2021 Climate Change Executive Order directs the Secretary of Interior to impose a moratorium on new oil and natural gas leases on public lands, or offshore waters to the extent possible, and launch a rigorous review of all existing leasing and permitting practices related to fossil fuel development on public lands. This moratorium may include restrictions of approving right-of-ways that could help build out midstream infrastructure needed to help reduce flaring. Any restrictions to building out pipelines or necessary infrastructure by federal, state and tribal governments could make flaring worse.

Rules regarding crude oil shipments by rail may pose unique hazards that may have an adverse effect on our operations. The NDI Commission requires that crude oil produced in the Bakken Petroleum System be conditioned to remove lighter, volatile hydrocarbons and improve the marketability and safe transportation of the crude oil by rail. The U.S. Department of Transportation rule regarding the safe transportation of flammable liquids by rail imposes certain requirements on "offerors" of crude oil, including sampling, testing, and certification requirements. These conditioning requirements, and any similar future obligations imposed at the state or federal level, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate. Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various species and wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened and endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species as threatened or endangered in areas where we operate 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 a material adverse effect on our ability to develop and produce our reserves.

Environmental laws are complex and potentially burdensome for QEP's operations. QEP must comply with numerous and complex federal, state and tribal environmental regulations governing activities on federal, state and tribal lands, notably including the federal Clean Air Act, Clean Water Act, SDWA, OPA, CERCLA, RCRA, NEPA, the Endangered Species Act, the National Historic Preservation Act and similar state laws and tribal codes. Federal, state and tribal regulatory agencies frequently impose conditions on the Company's activities under these laws. These restrictions have become more stringent over time and can limit or prevent exploration and production on significant portions of the Company's leasehold. These laws also allow certain ENGOs to oppose drilling on some of QEP's federal and state leases. These organizations sometimes sue federal and state regulatory agencies and/or the Company under these laws alleging procedural violations in an attempt to stop, limit or delay oil and gas development on public and other lands.

QEP may not be able to obtain the permits and approvals necessary to continue and expand its operations. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. It may be costly and time consuming to comply with requirements imposed by these authorities, and compliance may result in delays in the commencement or continuation of the Company's exploration and production. Further, the public may comment on and otherwise seek to influence the permitting process, including through intervention in the courts. Accordingly, necessary permits may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict QEP's ability to conduct its operations or to do so profitably. In addition, the BIA implemented final regulations in March 2016, which significantly altered the procedure for obtaining rights-of-way on tribal lands. These new regulations may increase the time and cost required to obtain necessary rights-of-way for QEP's operations on tribal lands, and rights-of-way issued under these new regulations expressly make QEP subject to a tribe's regulatory and judicial jurisdiction.

In April 2020, the U.S. District Court for the District of Montana vacated the Corps' 2017 issuance of NWP 12 (the general permit issued by the Corps for pipelines and utility projects). In May 2020, the court narrowed its ruling, vacating and enjoining the use of NWP 12 only as it relates to construction of new oil and gas pipelines. The Corps appealed the decision to the U.S. Court of Appeals for the Ninth Circuit and the litigation is ongoing. In July 2020, the U.S. Supreme Court granted in part and denied in part the Corps' application for stay of the order issued by the district court. The U.S. Supreme Court stayed the lower court order except as it applies to the Keystone XL pipeline. The stay is to remain in place pending disposition of the appeal currently pending before the Ninth Circuit. In January 2021, the Corps released the final version of a rule renewing twelve of its NWPs, including NWP 12. The new rule splits NWP 12 into three parts; NWP 12 will continue to be available for oil and gas pipelines, while new NWP 57 will be available for electric utility line and telecommunications activities, and a new NWP 58 will be available for utility line activities for water and other substances. The new rule also eliminates preconstruction notice requirements for NWP 12 for several conditions that used to require such notice, but also now requires new oil and gas pipeline projects that exceed 250 miles in length to give preconstruction notice and obtain approval before proceeding. We cannot predict at this time how the new rule will be implemented, because permits are issued by the local Corps district offices, or whether it will remain in place following the review required by the Biden executive orders. However, if new oil and gas pipeline projects are unable to utilize NWP 12 or identify an alternate means of Clean Water Act compliance, such projects could be significantly delayed, which could have an adverse impact on our operations.

Our operations on the Fort Berthold Indian Reservation of the Three Affiliated Tribes in North Dakota are subject to various federal, state, local and tribal regulations and laws, any of which may increase our costs and have an adverse impact on our ability to effectively conduct our operations. Various federal agencies within the U.S. Department of the Interior, particularly the BIA and the Office of Natural Resource Revenue, along with the Three Affiliated Tribes of the Fort Berthold Indian Reservation (TAT), promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation. In addition, the TAT is a sovereign nation having the right to enforce laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, approvals and other conditions that apply to lessees, operators and contractors conducting operations on the Fort Berthold Indian Reservation. Lessees and operators conducting operations on tribal lands may be subject to the TAT's court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

Federal and state hydraulic fracturing legislation or regulatory initiatives could increase QEP's costs and restrict its access to oil and gas reserves. Currently, well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve oil and gas well design and operation. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and issued guidance related to this asserted regulatory authority. The EPA may consider seeking to further regulate hydraulic fracturing fluids and/or the components of those fluids. At the state and local level, some states and local governments have adopted, and other states and local governments have considered adopting regulations and moratoria that could restrict or prohibit hydraulic fracturing in certain circumstances. If new or more stringent federal, state, tribal or local regulations, restrictions or moratoria are adopted in areas where QEP operates, QEP 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 drilling or stimulating wells in some areas.

In December 2016, the EPA released its final report on the potential for impacts to drinking water resources from hydraulic fracturing. The study concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances. Many other recent studies and reports have examined the potential impacts of hydraulic fracturing on the public and the environment. These and future studies could form a basis for additional regulations, which could lead to operational burdens similar to those described above.

QEP's ability to produce oil and gas economically and in commercial quantities could be impaired if it is unable to acquire adequate supplies of water for its drilling and completion operations or is unable to dispose of or recycle the water or other waste at a reasonable cost and in accordance with applicable environmental rules. Water is an essential component of QEP’s drilling and hydraulic fracture stimulation processes. The hydraulic fracture stimulation process on which QEP depends to produce commercial quantities of oil and gas requires the use and disposal of significant quantities of water. The availability of disposal wells with sufficient capacity to receive all of the water produced from QEP's wells may affect QEP's production. In some cases, QEP may need to obtain water from new sources and transport it to drilling sites, resulting in increased costs. In recent years, West Texas has experienced a severe drought. Accordingly, QEP may experience difficulty in securing the necessary volumes of water for its operations. QEP's inability to timely secure sufficient amounts of water, or to dispose of or recycle the water used in its operations, could adversely impact its operations. Moreover, the imposition of new environmental regulations could include restrictions on QEP's ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase QEP's operating costs or may cause QEP to delay, curtail or discontinue its exploration and development plans, which could have a material adverse effect on its business, financial condition, results of operations and cash flows.

Legislation or regulatory initiatives intended to address induced seismicity could restrict QEP's drilling and production activities as well as QEP's ability to dispose of produced water gathered from such activities, which could have a material adverse effect on QEP's business. State and federal regulatory agencies have focused on a possible connection between the disposal of wastewater in underground injection wells, or to a lesser extent the hydraulic fracturing of oil and gas wells, and the increased occurrence of seismic activity in certain areas, and regulatory agencies at all levels are continuing to study the possible linkage between oil and natural gas activity and induced seismicity. For example, in 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of seismic activity that may be attributable to fluid injection or oil and natural gas extraction activities. In addition, a number of lawsuits have been filed, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in 2014, the TRRC published a new rule governing permitting or re-permitting of disposal wells that requires, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or applicant fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicate the well is likely or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

QEP operates injection wells and utilizes injection wells owned by third parties to dispose of large volumes of waste water associated with its drilling, completion and production operations. QEP disposes of these volumes of produced water pursuant to permits issued to QEP by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements or prohibitions on operating certain facilities, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations or the issuance of any orders or imposition of any requirements that restrict QEP's ability to use hydraulic fracturing or dispose of produced water gathered from its drilling and production activities by limiting volumes, injection pressures or rates, or restricting producing or disposal well locations, or requiring QEP to shut down disposal wells, could have a material adverse effect on QEP's business, financial condition and results of operations.

C***limate change and climate change legislation and regulatory initiatives, including renewable energy mandates could result in increased operating costs and decreased demand for the oil and natural gas that we produce***. Climate change, the costs that may be associated with its effects, the required use of renewable energy, and the regulation of GHG emissions have the potential to affect our business in many ways, including increasing the costs to provide our products, reducing the demand for and consumption of our products (due to changes in both costs and weather patterns) and negatively impacting the economic health of the regions in which we operate, all of which can create financial risks. In addition, if restrictions on GHG emissions and mandates for use of renewable energy significantly increase our costs to produce oil and gas, or significantly decrease demand for our products, the value of our oil and gas reserves may decrease. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. In addition, legislative and regulatory responses related to GHG emissions, climate change and renewable energy use may result in increased operating costs, delays in obtaining air emissions and other necessary permits for new or modified facilities and reduced demand for the oil, gas and NGL that QEP produces. Federal and state courts and administrative agencies are considering the scope and scale of potential climate-change-related regulation under various existing laws pertaining to the environment, energy use and energy resource development. Federal, state and local governments may also pass laws specifically aimed at GHG regulation, and mandating the use of renewable energy sources, such as wind power and solar energy, or restricting or banning the use of gasoline or diesel powered vehicles, which may reduce demand for oil and natural gas. Although Congress previously considered but did not adopt proposed legislation aimed at reducing GHG emissions, recent Congressional resolutions and the new Democratic majority in both the Senate and House of Representatives make it likely Congress will soon consider new legislation requiring decarbonization or use of renewable energy in much higher proportions. Recently, several states and local jurisdictions have pledged to remove internal combustion engines from their roads as early as 2035. Further, state and local governments may pursue additional litigation against oil and gas producers for damages allegedly resulting from climate change. QEP's ability to access and develop new oil and gas reserves may also be restricted by climate change regulations, including GHG reporting and regulation.

The EPA has adopted final regulations under the Clean Air Act for the measurement and reporting of GHG emitted from certain large facilities and, as discussed above, has adopted additional regulations, intended to include additional requirements to reduce methane and volatile organic compound emissions from oil and natural gas facilities. The status of those regulations is uncertain given the ongoing litigation, administrative reconsideration, final revisions to those rules announced in August 2020, and the prospects for legal challenges to such revisions. In addition, in January 2021, the administration issued an executive order calling on the EPA to, among other things, consider a proposed rule suspending, revising or rescinding the deregulatory amendments by September 2021. Additionally, in 2014, the United States Supreme Court upheld a portion of EPA's GHG stationary source permitting program in Utility Air Regulatory Group v. EPA, but also invalidated a portion of it. The Court's holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations to which QEP's operations are subject, including certain existing GHG permitting requirements.

In 2015, over 190 countries, including the U.S., met in Paris (COP 21) and agreed to reduce global emissions of GHG by entering into the Paris Climate Agreement. The Paris Climate Agreement provides for the cutting of carbon emissions every five years, beginning in 2023, and sets a goal of keeping global warming to a maximum limit of two degrees Celsius and a target limit of 1.5 degrees Celsius greater than pre-industrial levels. However, in November 2019, President Trump initiated the formal process to withdraw the United States from the Paris Climate Agreement with an effective withdrawal date of November 2020. The 2021 Climate Change Executive Order commenced the process for the U.S. reentering the Paris Climate Agreement, although the emissions pledges in connection with that effort have not yet been updated. State and local climate regulatory efforts are expected to increase. In several of the states in which QEP operates the regulatory authorities are considering various GHG registration and reduction programs, including methane leak detection monitoring and repair requirements specific to oil and gas facilities. In addition, the failure of the federal government to address climate change concerns, including, for example, a protracted delay by President Trump's administration in determining its own carbon-cost estimate (i.e., the estimate of how much carbon pollution costs society via climate damages) after rejecting the $40 per ton of carbon dioxide equivalent estimate of the Obama administration, could afford ENGOs additional opportunities to pursue further legal challenges to oil and gas drilling and pipeline projects.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events. In addition, warmer winters in some regions as a result of climate change could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are realized due to climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable. In January 2021, President Biden issued the 2021 Climate Change Executive Order. It sets goals of a carbon pollution free power sector by 2035 and a net zero economy by 2050.

A change in the jurisdictional characterization of some of our assets by federal, state, or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase. We believe that our gas gathering systems meet the traditional tests FERC has used to determine if a pipeline is a gas gathering pipeline and is, therefore, not subject to FERC jurisdiction. FERC, however, has not made any determinations with respect to the jurisdictional status of any of these gas gathering systems. The distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of ongoing litigation and, over time, FERC policy concerning which activities it regulates and which activities are excluded from its regulation has changed. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation.

In addition, QEP's crude oil pipelines (specifically the rates, terms and conditions for shipments) may also be subject to FERC regulation if QEP's crude oil pipelines provide part of the movement in interstate or foreign commerce for shippers (pursuant to the Interstate Commerce Act, as it existed on October 1, 1977, the Energy Policy Act of 1992 and related rules). QEP does not control the entire transportation path of all crude oil shipped on QEP's pipelines. Therefore, FERC regulation could be triggered by QEP's customers' transportation decisions.

FERC makes jurisdictional determinations for both natural gas gathering and crude oil lines on a case-by-case basis. The classification and regulation of our pipelines are subject to change based on future determinations by FERC, the courts, or Congress. A change in the jurisdictional characterization of some of our assets by federal, state, or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets, which could cause our revenues to decline and operating expenses to increase.

The taxation of independent producers is subject to change, and changes in tax law could increase our cost of doing business. We are subject to taxation by various taxing authorities at the federal, tribal, state and local levels where we do business. Legislation has been proposed in the past, and could be proposed and enacted in the future, that could increase the taxes or fees imposed on oil and natural gas extraction and properties, corporate and state tax rates, deductibility of expense items or impact the refundability of U.S. alternative minimum tax credits we currently expect to receive. Any such legislation could also impact our liquidity and result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil and natural gas. The 2021 Climate Change Executive Order directs federal agencies to eliminate "fossil fuel subsidies" as consistent with applicable law, which may implicate the treatment of oil and gas assets and production under the Code.

If we were to experience an "ownership change," we could be limited in our ability to use certain tax attributes arising prior to the ownership change to offset future taxable income. If we were to experience an "ownership change," as determined under section 382 of the Internal Revenue Code of 1986, as amended, our ability to offset taxable income arising after the ownership change by utilizing NOL's arising prior to the ownership change could be limited, possibly substantially. Additionally, the deductibility of disallowed interest expense carryforward, pursuant to the tax legislation enacted in December 2017 (Tax Cuts and Jobs Act), could also be limited post-ownership change. An ownership change would establish an annual limitation on the amount of our pre-ownership change losses, including NOL's, tax credits, and disallowed interest expense carryforward, that we could utilize in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate.

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse impact on QEP's ability to use derivative instruments to reduce the effect of commodity price volatility and other risks associated with its business. The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation, including, among other items, a requirement that certain transactions be cleared on exchanges as well as collateral or "margin" requirements for certain uncleared swaps. The Dodd-Frank Act provides for an exception from these clearing requirements for commercial end-users, such as QEP. The Dodd-Frank Act and the rules promulgated thereunder could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks QEP encounters, reduce QEP's ability to monetize or restructure QEP's existing derivative contracts, increase the administrative burden and regulatory risk associated with entering into certain derivative contracts, and increase QEP's exposure to less creditworthy counterparties. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and gas. QEP revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and its regulations is to lower commodity prices. Any of these consequences could affect the pricing of derivatives and make it more difficult for us to enter into derivative transactions, which could have a material and adverse effect on QEP's business, financial condition and results of operations. The rulemaking and implementation process are ongoing and the ultimate effect of the adopted rules and regulations and any future rules and regulations on QEP's business remains uncertain.

General Risks

Events of force majeure may limit our ability to operate our business and could adversely affect our operating results.
The weather, unforeseen events, or other events of force majeure in the areas in which we operate could cause disruptions and, in some cases, suspension of our operations. This suspension could result from a direct impact to our properties or result from an indirect impact by a disruption or suspension of the operations of those upon whom we rely for gathering, processing and transportation. If disruption or suspension were to persist for a long period, our results of operations would be materially impacted.

Changes in LIBOR reporting practices or the method in which LIBOR is determined may adversely affect the market value of QEP’s current or future debt obligations, including QEP’s revolving credit facility. The interest rate in QEP's revolving credit facility is indexed to the London Interbank Offered Rate (LIBOR). On July 27, 2017, the Financial Conduct Authority (the FCA) announced its intention to phase out LIBOR rates by the end of 2021. It is unclear whether LIBOR will cease to exist or if new methods of calculating LIBOR will be established such that it continues to exist after 2021, or whether any alternative reference rate will attain market acceptance as a replacement for LIBOR. It is not possible to predict the further effect of the rules of the FCA, any changes in the methods by which LIBOR is determined or any other reforms to LIBOR that may be enacted in the United Kingdom, the European Union or elsewhere. Any such developments may cause LIBOR to perform differently than in the past, or cease to exist. In addition, any other legal or regulatory changes made by the FCA, the European Commission or any other successor governance or oversight body, or future changes adopted by such body, in the method by which LIBOR is determined or the change from LIBOR to a successor benchmark may result in, among other things, a sudden or prolonged increase or decrease in LIBOR, a delay in the publication of LIBOR, and changes in the rules or methodologies in LIBOR, which may discourage market participants from continuing to administer or to participate in LIBOR’s determination, and, in certain situations, could result in LIBOR no longer being determined and published. If a published U.S. dollar LIBOR rate is unavailable after 2021, the interest rates on our debt which are indexed to LIBOR will be determined using a benchmark replacement as defined in the Eighth Amendment of the credit facility, which may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on such debt if U.S. dollar LIBOR was available in its current form. Further, the same costs and risks that may lead to the discontinuation or unavailability of U.S. dollar LIBOR may make one or more of the benchmark replacement methods impossible or impracticable to determine. Any of these proposals or consequences could have a material adverse effect on our financing costs. As of February 17, 2021, we had no outstanding borrowings under our revolving credit facility.

Failure of the Company's controls and procedures to detect errors or fraud could seriously harm its business and results of operations. QEP's management, including its chief executive officer and chief financial officer, does not expect that the Company's internal controls and disclosure controls will prevent all possible errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are being met. In addition, the design of a control system must reflect the fact that there are resource constraints, and the benefit of controls are evaluated relative to their costs. Because of the inherent limitations in all control systems, no evaluation of QEP's controls can provide absolute assurance that all control issues and instances of fraud, if any, in the Company have been detected. The design of any system of controls is based in part upon the likelihood of future events, and there can be no assurance that any design will succeed in achieving its intended goals under all potential future conditions. Over time, a control may become inadequate because of changes in conditions, or the degree of compliance with its policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur without detection. Violations of any laws or regulations caused by either failure of our internal controls related to regulatory compliance or failure of our employees to comply with our internal policies could result in substantial civil or criminal fines. In addition, legal enforcement may be impacted by significant incentives for whistleblowers.

QEP is exposed to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss. The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, QEP depends on digital technologies to interpret seismic data; manage drilling rigs, production equipment and gathering systems; conduct reservoir modeling and reserves estimation; and process and record financial and operating data. Pipelines, refineries, power stations and distribution points for both fuels and electricity are becoming more interconnected by computer systems. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. QEP's technologies, systems and networks, and those of its vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. QEP does not maintain specialized insurance for possible losses resulting from a cyberattack on its assets that may shut down all or part of QEP's business. QEP's systems for protecting against cyber security risks may not be sufficient.

While QEP and its vendors have experienced cyberattacks, QEP is not aware of any material losses relating to cyberattacks; however, there is no assurance that QEP will not suffer such losses in the future. In addition, as cybersecurity threats continue to evolve, QEP may expend additional resources to continue to modify or enhance its protective measures or to investigate or remediate any cybersecurity vulnerabilities.

We may be unable to quickly adapt to changes in market/investor priorities. Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With the continued downturn and volatility in oil and natural gas prices, and the possibility that interest rates will rise in the near term, increasing the cost of borrowing, the market and investor emphasis has elevated capital efficiency and free cash flow from earnings as potentially the key drivers for energy companies, especially those primarily focused in the shale play arena. Shifts in focus such as these sometimes require changes in planning and resource management, which cannot necessarily occur instantaneously. Any delay in responding to such changes in market sentiment or perception can result in the investment community in general having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed “efficient,” which can have a negative impact on the price of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. Item 103 of the SEC's Regulation S-K requires disclosure of material pending legal proceedings, other than ordinary routine litigation incidental to the business, to which QEP or any of its subsidiaries is a party or of which any of their property is the subject. Item 103 also requires disclosure of certain environmental matters when a governmental authority is a party to the proceedings and the proceedings involve potential monetary sanctions that the Company reasonably believes could exceed $300,000.

Refer to Note 10 – Commitments and Contingencies in Item 8 of Part II of this Annual Report on Form 10-K for more information regarding our legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

QEP's common stock is listed and traded on the New York Stock Exchange (NYSE:QEP). As of January 31, 2021, QEP had 4,697 shareholders of record.

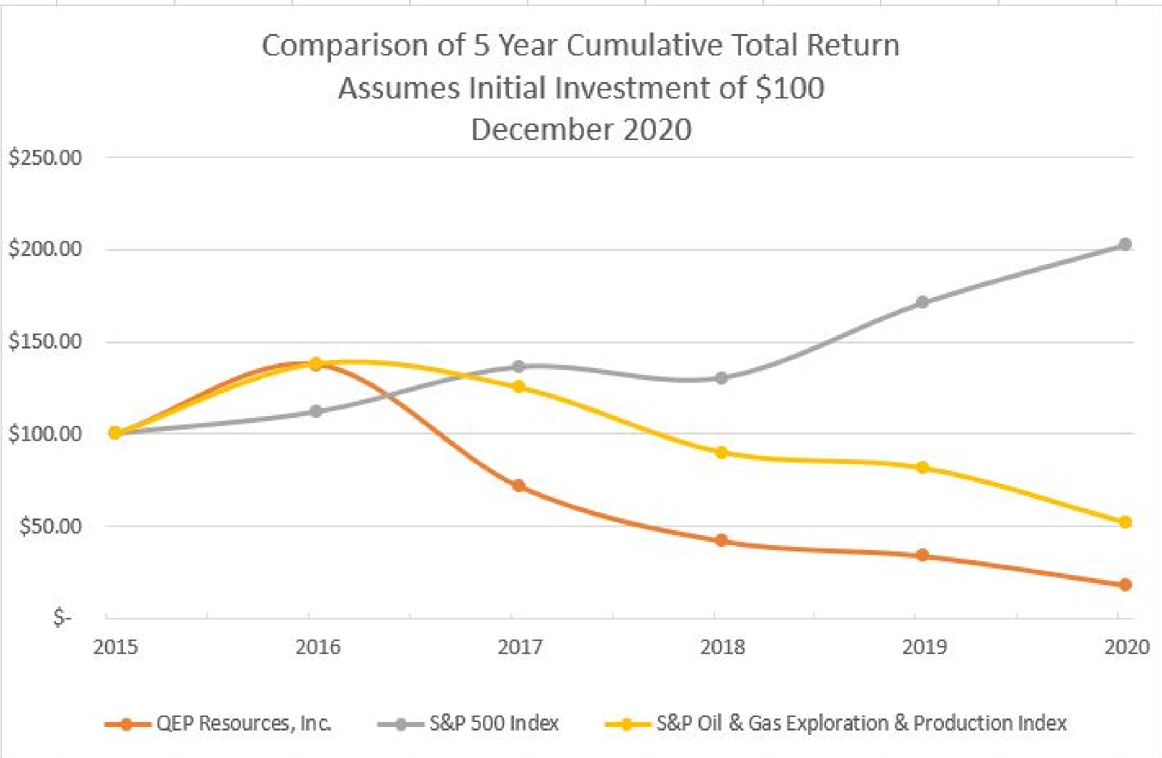
Stock Performance Graph

The following stock performance information is not deemed to be "soliciting material" or to be "filed" with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934 or to the liabilities of Section 18 of the Securities Exchange Act of 1934, and will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent QEP specifically incorporates it by reference into such a filing.

QEP's peer group consists of the companies included in the S&P Oil & Gas Exploration & Production Index.

The performance presentation shown below is being furnished as required by applicable rules of the SEC and was prepared using the following assumptions:

- A $100 investment was made in QEP's common stock, the S&P 500 Index and the S&P Oil & Gas Exploration & Production Index as of December 31, 2015, and its relative performance is tracked through December 31, 2020;
- Investment in the Company's peer group was weighted based on the stock market capitalization of each individual company within the peer group at the beginning of each period for which a return is indicated; and
- Dividends, if any, were reinvested on the relevant payment dates. QEP suspended the payment of dividends in February 2016, reinstated its quarterly dividend in August 2019 and suspended the payment of dividends again in March 2020.



	2015	2016	2017	2018	2019	2020
QEP Resources, Inc.	$ 100.00	$ 137.39	$ 71.42	$ 42.02	$ 33.95	$ 18.22
S&P 500 Index – Total Returns	$ 100.00	$ 111.95	$ 136.38	$ 130.39	$ 171.44	$ 202.96
S&P Oil & Gas Exploration & Production Index	$ 100.00	$ 138.28	$ 125.19	$ 90.02	$ 81.52	$ 51.92

Recent Sales of Unregistered Securities; Purchases of Equity Securities by QEP and Affiliated Purchasers

On February 28, 2018, QEP announced the authorization by its Board of Directors to repurchase up to $1.25 billion of the Company's outstanding shares of common stock. On July 28, 2020, the Board suspended the repurchase program.

The repurchases of shares during the three months ended December 31, 2020, were in connection with the settlement of income tax and related benefit withholding obligations arising from the vesting of restricted share grants.

ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2020, is provided in the table below. Refer to Items 7 and 8 in Part II of this Annual Report on Form 10-K for further discussion of the factors affecting the comparability of the Company's financial data.

	Year Ended December 31,				
	2020[(1)]	2019[(1)]	2018[(1)]	2017[(1)]	2016[(1)]
Statement of Operations Data	(in millions, except per share amounts)				
Revenues[(2)]	**$ 724.4**	$ 1,206.2	$ 1,932.6	$ 1,622.9	$ 1,377.1
Operating income (loss)	**$ (223.7)**	$ 157.5	$ (1,260.4)	$ 101.5	$ (1,600.7)
Net income (loss)[(3)(4)]	**$ 3.2**	$ (97.3)	$ (1,011.6)	$ 269.3	$ (1,245.0)
Earnings (loss) per common share					
Basic	**$ 0.01**	$ (0.41)	$ (4.25)	$ 1.12	$ (5.62)
Diluted	**0.01**	(0.41)	(4.25)	1.12	(5.62)
Weighted-average common shares outstanding					
Used in basic calculation	**241.6**	237.7	237.9	240.6	221.7
Used in diluted calculation	**241.6**	237.7	237.9	240.6	221.7
Cash dividends declared per common share	**$ 0.02**	$ 0.04	$ —	$ —	$ —
Balance Sheet Data					
Total Assets at December 31,[(5)]	**$ 5,114.2**	$ 5,477.8	$ 6,117.8	$ 7,394.8	$ 7,245.4
Capitalization at December 31,					
Long-term debt	**$ 1,591.3**	$ 2,015.6	$ 2,507.1	$ 2,160.8	$ 2,020.9
Total Common Shareholders' Equity	**2,670.2**	2,660.6	2,750.9	3,797.9	3,502.7
Total Capitalization	**$ 4,261.5**	$ 4,676.2	$ 5,258.0	$ 5,958.7	$ 5,523.6
Statement of Cash Flows Data					
Net cash provided by (used in) operating activities	**$ 673.2**	$ 566.9	$ 816.2	$ 600.2	$ 667.2
Expenditures for property, plant and equipment	**$ (357.6)**	$ (566.2)	$ (1,299.7)	$ (1,974.8)	$ (1,208.1)
Net cash provided by (used in) investing activities	**$ (343.8)**	$ 112.7	$ (1,056.1)	$ (1,168.0)	$ (1,179.1)
Net cash provided by (used in) financing activities	**$ (433.5)**	$ (511.3)	$ 244.6	$ 125.8	$ 583.1
Non-GAAP Measures					
Adjusted EBITDA[(6)]	**$ 649.9**	$ 663.6	$ 974.8	$ 736.1	$ 628.1
Free Cash Flow[(7)]	**$ 225.4**	$ (9.8)	$ (314.9)	$ (588.4)	$ (12.8)

(1) The results are impacted by various acquisitions and divestitures. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information on these transactions.

(2) In the first quarter of 2018, QEP adopted ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*, using the modified retrospective approach. During the years ended December 31, 2020, 2019 and 2018, the revenues are impacted by the adoption of this ASU. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(3) Net income for 2017 was positively impacted by a $307.9 million tax benefit, primarily due to a revaluation of our net deferred tax liability to reflect the federal rate change resulting from 35% to 21% under the Tax Cuts and Jobs Act.

(4) Net income for 2020 was positively impacted by a $79.9 million tax benefit, primarily due to the remeasurement of deferred taxes from NOL carrybacks under the CARES Act to a year with a higher federal tax rate.

(5) On January 1, 2019, QEP adopted ASU No. 2016-02, *Leases (Topic 842)*, using the modified retrospective approach. As of December 31, 2020 and 2019, total assets are impacted by the adoption of this ASU. Refer to Note 7 – Leases in Item 8 of Part II of this Annual Report on Form 10-K for more information

(6) Adjusted EBITDA is a non-GAAP financial measure. See Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report on Form 10-K for additional disclosures related to Adjusted EBITDA.

(7) Free Cash Flow is a non-GAAP financial measure. See Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, in this Annual Report on Form 10-K for additional disclosures related to Free Cash Flow.

The following table reconciles QEP's Net Income (Loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Year Ended December 31,				
	2020	2019	2018	2017	2016
	(in millions)				
Net income (loss)	**$ 3.2**	$ (97.3)	$ (1,011.6)	$ 269.3	$ (1,245.0)
Interest expense	**113.7**	128.1	149.4	137.8	143.2
Interest and other (income) expense	**(9.8)**	(4.7)	9.6	(1.6)	(23.7)
Income tax provision (benefit)	**(79.9)**	(43.0)	(317.4)	(312.2)	(708.2)
Depreciation, depletion and amortization	**574.0**	540.0	857.1	754.5	871.1
Unrealized (gains) losses on derivative contracts	**59.2**	138.3	(248.5)	(40.0)	367.0
Exploration expenses	**0.2**	0.1	0.3	22.0	1.7
Net (gain) loss from asset sales, inclusive of restructuring costs	**(1.2)**	(3.9)	(25.0)	(213.5)	(5.0)
Impairment	**8.7**	5.0	1,560.9	78.9	1,194.3
(Gain) loss from early extinguishment of debt	**(18.2)**	1.0	—	32.7	—
Other[1]	**—**	—	—	8.2	32.7
Adjusted EBITDA	**$ 649.9**	$ 663.6	$ 974.8	$ 736.1	$ 628.1

(1) Reflects legal expenses and loss contingencies incurred during the years ended December 31, 2017 and 2016. The Company believes that these amounts do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded these amounts from the calculation of Adjusted EBITDA.

The following table reconciles QEP's Net Cash Provided by (Used in) Operating Activities (a GAAP measure) to Free Cash Flow. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Year Ended December 31,				
	2020	2019	2018	2017	2016
	(in millions)				
Net Cash Provided by (Used in) Operating Activities	**$ 673.2**	$ 566.9	$ 816.2	$ 600.2	$ 667.2
Exploration expense	**0.2**	0.1	0.3	22.0	1.7
Amortization of debt issuance costs and discounts	**(4.7)**	(5.4)	(5.4)	(6.2)	(6.4)
Interest expense	**113.7**	128.1	149.4	137.8	143.2
Unrealized (gains) losses on marketable securities	**3.2**	3.9	(1.2)	2.9	1.4
Interest and other (income) expense	**(9.8)**	(4.7)	9.6	(1.6)	(23.7)
Deferred income (taxes) benefit	**(110.6)**	(4.3)	247.6	314.8	651.3
Income tax provision (benefit)	**(79.9)**	(43.0)	(317.4)	(312.2)	(708.2)
Non-cash share-based compensation	**(12.4)**	(20.8)	(30.9)	(26.9)	(26.0)
Dry hole exploratory well expense	**—**	—	—	(21.3)	—
Other EBITDA adjustments[1]	**—**	—	—	8.2	32.7
Bargain purchase gain from acquisitions	**—**	—	—	(0.4)	22.6
Other non-cash activity	**—**	—	—	9.4	—
Changes in operating assets and liabilities	**77.0**	42.8	106.6	9.4	(127.7)
Adjusted EBITDA	**$ 649.9**	$ 663.6	$ 974.8	$ 736.1	$ 628.1
Non-cash share-based compensation	**12.4**	20.8	30.9	26.9	26.0
Interest expense, excluding amortization of debt issuance costs and discounts	**(109.0)**	(122.7)	(144.0)	(131.6)	(136.8)
Accrued property, plant and equipment capital expenditures	**(327.9)**	(571.5)	(1,176.6)	(1,219.8)	(530.1)
Free Cash Flow	**$ 225.4**	$ (9.8)	$ (314.9)	$ (588.4)	$ (12.8)

[1] Reflects legal expenses and loss contingencies incurred during the years ended December 31, 2017 and 2016. The Company believes that these amounts do not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded these amounts from the calculation of Adjusted EBITDA.

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

Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company's operating results. MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes included in Item 8 of Part II of this Annual Report on Form 10-K and also with "Risk Factors" in Item 1A of this report.

The following information updates the discussion of QEP's financial condition provided in its 2019 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2020 and 2019. Refer to Item 7 of Part II of the 2019 Annual Report on Form 10-K filing for discussion and analysis of the changes in results of operations between the years ended December 31, 2019 and 2018.

OVERVIEW

QEP is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

As a result of the reduction of the Company's operational footprint in 2019, QEP reassessed its organizational needs and significantly reduced its general and administrative expense to ensure its cost structure is competitive with industry peers.

As a part of the strategic initiatives and reduction in general and administrative expense, QEP incurred costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 3 – Acquisitions and Divestitures and Note 8 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

The Company continues to focus on reducing its operating costs, per well drilling costs, general and administrative costs and managing its liquidity. We believe our plan to generate Free Cash Flow (a non-GAAP financial measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) on an annual basis will allow us to further strengthen our balance sheet and ultimately return capital to shareholders.

Merger

On December 20, 2020, the Company entered into an Agreement and Plan of Merger (Merger Agreement) with Diamondback Energy, Inc. (Diamondback) and Bohemia Merger Sub, Inc., a wholly owned subsidiary of Diamondback (Merger Sub), which provides that, among other things, and subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into QEP, with QEP surviving as a direct, wholly owned subsidiary of Diamondback (Merger). Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of the Company (other than any Excluded Shares, any Converted Shares and Company Restricted Stock Awards (each as defined in the Merger Agreement)) will be converted into the right to receive 0.05 shares, par value $0.01 per share, of common stock of Diamondback (Merger Consideration). The Merger Agreement also addresses the treatment of QEP equity awards in the Merger. Diamondback’s common stock is listed and traded on the NASDAQ Global Select Market under the symbol "FANG". The transaction was unanimously approved by the Boards of Directors of both companies. The Merger is expected to close late in the first quarter of 2021, and is subject to the approval of the Company's stockholders and other customary closing conditions. During the year ended December 31, 2020, the Company incurred $4.5 million of merger costs recognized in "General and administrative" expense on the Consolidated Statements of Operations and $5.0 million of additional merger costs were recognized in "Prepaid expenses" on the Consolidated Balance Sheets as of December 31, 2020.

For additional information regarding the Merger and QEP’s Board’s process and rationale for the Merger, please see the proxy statement and other documents filed with the SEC as they become available.

Acquisitions and Divestitures

QEP's strategy is to generate Free Cash Flow, and it believes its inventory of identified drilling locations provides a solid base to achieve its strategy, but it will continue to evaluate and potentially acquire properties in its operating areas to add additional development opportunities and facilitate the drilling of long lateral wells.

Acquisitions

During the years ended December 31, 2020 and 2019, QEP acquired various oil and gas properties, which primarily included proved leasehold acreage in the Permian Basin, for an aggregate purchase price of $4.1 million and $3.5 million, respectively, subject to post-closing purchase price adjustments.

Divestitures

During the year ended December 31, 2020, QEP received net cash proceeds of $13.8 million and recorded a pre-tax gain on sale of $1.2 million, primarily related to the divestiture of properties outside its main operating areas.

In January 2019, QEP sold its Haynesville/Cotton Valley assets (Haynesville Divestiture) and during the year ended December 31, 2019, reached final settlement on asserted environmental and title defects and received aggregate net cash proceeds of $633.9 million. QEP recorded a total net pre-tax loss on sale, including restructuring costs, of $4.0 million. During the years ended December 31, 2019 and 2018, QEP recorded a pre-tax loss on sale, including restructuring costs, of $1.0 million and $3.0 million, respectively, which was recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

In addition to the Haynesville Divestiture, during the year ended December 31, 2019, QEP received net cash proceeds of $45.0 million and recorded a net pre-tax gain on sale of $4.9 million primarily related to the divestiture of properties outside our main operating areas.

In November 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a purchase and sale agreement for its assets in the Williston Basin for a purchase price of $1,725.0 million, subject to purchase price adjustments. The purchase price was comprised of $1,650.0 million in cash and contractual rights to receive $75.0 million of the buyer's common stock if certain conditions were met. The transaction was subject to certain conditions, including, but not limited to, approval by the buyer's shareholders and regulatory approvals. As a result of signing the purchase and sale agreement, the Company recorded impairments of proved and unproved properties of $1,560.9 million during the year ended December 31, 2018. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement (Terminated Williston Basin Divestiture). Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

In September 2018, QEP sold its natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for net cash proceeds of $153.0 million (Uinta Basin Divestiture). In addition, during the years ended December 31, 2019 and 2018, QEP recorded a pre-tax loss of $0.2 million and $12.6 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. In conjunction with the Uinta Basin Divestiture, QEP recorded $402.8 million of proved and unproved properties impairment during the year ended December 31, 2018. Refer to Note 1 – Summary of Significant Accounting Policies and Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

As a part of the strategic initiatives and the associated divestitures, QEP has incurred costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 8 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Financial and Operating Highlights

During the year ended December 31, 2020, QEP:

- Generated net income of $3.2 million, or $0.01 per diluted share;
- Reported $649.9 million of Adjusted EBITDA (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K), a 2% decrease from 2019;
- Reported net cash provided by operating activities of $673.2 million;
- Reported Free Cash Flow (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) of $225.4 million in 2020 compared to Free Cash Flow outspend of $9.8 million in 2019;
- Reduced general and administrative expenses by 40% compared to 2019;
- Received $170.7 million in AMT credits refunds due to changes enacted by the CARES Act, inclusive of $5.6 million in interest income;
- Reduced principal amount of outstanding debt by $430.5 million;
- Recorded an additional income tax receivable of $61.6 million for AMT credit refunds related to NOL carrybacks due to changes enacted by the CARES Act;
- Reported year-end total proved reserves of 363.4 MMboe, including proved crude oil and condensate reserves of 237.9 MMbbls;
- Delivered oil and condensate production of 12.6 MMbbls in the Permian Basin;
- Delivered oil equivalent production of 30.3 MMboe;
- Incurred capital expenditures (excluding property acquisitions) of $327.9 million, a 43% decrease from 2019; and
- Entered into the Merger Agreement on December 20, 2020, with Diamondback and Merger Sub, pursuant to which QEP will become a direct, wholly owned subsidiary of Diamondback.

Outlook

The novel Coronavirus disease (COVID-19) has created unprecedented challenges for our industry, customers and employees. Throughout the global pandemic, the Company has continued to take actions suggested by the Centers for Disease Control and Prevention as well as state and local governments in the areas in which the Company operates to protect the core of its business and to ensure the health and safety of its employees, business partners and communities. Starting in March 2020, the Company instituted various measures, including remote working and business travel restrictions, and we remain engaged with our business and community partners on how we can assist them during this time. The Company continues to evaluate safeguards and has implemented procedures and policies to help protect the health and safety of the portion of the workforce whose jobs cannot be completed remotely, including those who run our field operations. We continue to monitor the guidelines and recommendations provided by the relevant authorities, and we will continue to ensure we are implementing the suggested protocols to help reduce the spread of the virus.

In light of market conditions, during the year ended December 31, 2020, the Company took significant steps to proactively manage its cash flow and preserve liquidity by suspending completion operations in the Permian Basin in March 2020 until the fourth quarter of 2020. In the Williston Basin, operated completion activity was reduced and the refracturing program was suspended in the second quarter of 2020 through the end of 2020. While these decisions resulted in lower oil production during the year, the Company has started to see the market recover to pre-pandemic levels, and has added a second drilling rig to the Permian Basin to increase production in the area. The Company believes that it will be able to maintain positive cash flow and protect its balance sheet, with the ultimate goal of protecting shareholder returns over the long term. In the event future market conditions return to near historic lows, we are prepared to reduce activity further for an extended period and continue to reduce expenses and per well costs to the lowest and most efficient structure possible.

Due to the Company’s derivative positions and the continued initiative in reducing drilling and completion costs, the Company expects to generate Free Cash Flow in 2021. In addition to generating Free Cash Flow, changes enacted under the CARES Act have created significant income tax refunds for the Company. During the year ended December 31, 2020, the Company received $170.7 million in AMT credit refunds, inclusive of $5.6 million in interest income, and as of December 31, 2020 the Company has recorded an additional $61.6 million income tax receivable for AMT credit refunds, of which $30.7 million is expected to be received in the next 12 months. The Company expects that the generation of Free Cash Flow, cash on hand, the AMT credit refunds and, as needed, borrowings made under its revolving credit facility will be sufficient to meet its liquidity needs for the next 12 months.

The Company believes that the overall reduction of global spending on new development projects, especially in the U.S., will cause a reduction in the global oil supply, and that the eventual full recovery from the COVID-19 pandemic will cause demand to be more in line with previously anticipated levels and, consequently, continue to cause oil prices to improve. As a result of the actions taken, and continuing to be taken, and the expected stabilization of the global economy, the Company expects to emerge in a stronger position.

Based on current commodity prices, we expect to be able to fund our planned capital program for 2021 with cash on hand, cash flow from operating activities and, as needed, borrowings under our revolving credit facility. We continuously evaluate our level of drilling and completion activity in light of commodity prices, drilling results and changes in our operating and development costs and will adjust our capital investment program based on such evaluations. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures.

Factors Affecting Results of Operations

Strategic Initiatives

During the years ended December 31, 2020 and 2019, we continued to pursue several strategic initiatives to maximize shareholder value. Organizational modifications due to these strategic initiatives can alter risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; and impact corporate strategy – all of which could adversely affect our results of operations. For example, during 2019, we incurred significant general and administrative expense, including transaction costs, retention bonuses and severance payments, in connection with the strategic initiatives. Refer to Note 8 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Supply, Demand, Market Risk and their Impact on Oil and Gas Prices

Crude oil prices were negatively impacted by a variety of factors affecting current and expected supply and demand dynamics, including: the COVID-19 pandemic and related shut-down of various sectors of the global economy, which has resulted in a significant reduction in global demand for crude oil; resilient U.S. supply driven by advances in drilling and completion technologies; and the delay of an agreement in early 2020 among members of the Organization of Petroleum Exporting Countries (OPEC) and other oil producing countries regarding production levels, resulting in an increased supply in the global market. Other factors impacting the supply and demand of our products include weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors, the majority of which are outside our control. While OPEC and other oil producing countries have reduced production levels, and U.S. production has declined, a significant crude oil price recovery is not expected until global supply matches current lower levels of demand caused by the factors mentioned above, including the COVID-19 pandemic. The Company cannot predict if or when commodity prices will stabilize or at what levels.

Changes in the market prices for oil, gas and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling and completion activity and related capital expenditures, our proved undeveloped (PUD) reserves conversion rate, liquidity, rate of growth, costs of goods and services required to drill, complete and operate wells, and the carrying value of its oil and gas properties. The decline in price of crude oil negatively impacted our oil revenue during the year ended December 31, 2020, but the value of our realized oil derivatives portfolio increased significantly, helping to offset the negative impact. Additionally, the volatility in commodity prices has impacted the Company's stock price and the fair value of the Company's debt securities, all of which impact our financial and operating results. Due to the changes in our drilling plans, our 2020 PUD conversions were 30.1 MMboe, or 21% lower than originally anticipated. Our future drilling plans, including our level of expenditures for the development of our oil and condensate reserves, total PUD reserves, operations and financial condition may be materially and adversely affected by declines in future oil prices.

QEP's producing properties are primarily located in the Permian and Williston basins. As a result of our lack of diversification in asset type and limited geographic diversification, any delays or interruptions of production caused by factors such as governmental regulation, transportation capacity constraints, curtailment of production or interruption of transportation, price fluctuations, natural disasters or shutdowns of the pipelines connecting our production to refineries would have a significantly greater impact on our results of operations than if we possessed more diverse assets and locations.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including global economic issues impacted by COVID-19; political and civil unrest; oil producing countries' oil production and policies regarding production quotas; actions taken by the United States Congress and the President of the United States; the U.S. federal budget deficit; changes in regulatory oversight policy; the impact of regulations and public and financial market sentiment regarding environmental, social and governance matters; commodity price volatility; tariffs on goods we use in our operations or on the products we sell; the impact of a potential increase in interest rates; volatility in various global currencies; and other factors. A dramatic decline in regional or global economic conditions, a major recession or depression, regional political instability, economic sanctions, war, or other factors beyond the control of QEP have had, and could have, a significant impact on short-term and long-term oil and condensate, gas and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs and which could materially impact the Company's financial position, results of operations and cash flow from operations. Disruption to the global oil supply system, political and/or economic instability, fluctuations in currency values, and/or other factors could trigger additional volatility in oil prices.

Due to continued global economic uncertainty and the corresponding volatility of commodity prices, QEP continues to focus on maintaining a sufficient liquidity position to ensure financial flexibility. QEP uses commodity derivatives to reduce the volatility of the prices QEP receives for a portion of its production and to partially protect cash flow and returns on invested capital from a drop in commodity prices. Generally, QEP intends to enter into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. Gains on settled derivatives offset a large portion of the impact of the recent decline in oil prices and our oil revenues. See Item 7A – "Quantitative and Qualitative Disclosures about Market Risk – Commodity Price Risk Management", of Part II of this Annual Report on Form 10-K for further details concerning QEP's commodity derivatives transactions.

Potential for Future Asset Impairments
The carrying values of the Company's properties are sensitive to declines in oil, gas and NGL prices as well as increases in various development and operating costs and expenses and, therefore, are at risk of impairment. When an indicator of impairment is identified the Company uses a cash flow model to assess its proved properties and operating lease right-of-use (ROU) assets for impairment. The cash flow model includes numerous assumptions, including estimates of future oil and condensate, gas and NGL production, estimates of future prices for production that are based on the price forecast that management uses to make investment decisions, including estimates of basis differentials, future operating costs, transportation expenses, production taxes, and development costs that management believes are consistent with its price forecast, and discount rates. Management also considers a number of other factors, including the forward curve for future oil and gas prices and developments in regional transportation infrastructure, as well as merger agreements and purchase and sale agreements, if applicable, when developing its estimate of future prices for production. All inputs for the cash flow model are evaluated at each date of estimate.

We base our estimates on projected financial information that we believe to be reasonably likely to occur. An assessment of the sensitivity of our capitalized costs to changes in the assumptions in our cash flow calculations is not practicable, given the numerous assumptions (e.g., future oil, gas and NGL prices; production and reserves; pace and timing of development plans; timing of capital expenditures; operating costs; drilling and development costs; and inflation and discount rates) that can materially affect our estimates. Unfavorable adjustments to some of the above listed assumptions would likely be offset by favorable adjustments in other assumptions. For example, the impact of sustained reduced oil, gas and NGL prices on future undiscounted cash flows would likely be offset by lower drilling and development costs and lower operating costs. The signing of a merger or purchase and sale agreement could also cause the Company to recognize an impairment of proved properties. For assets subject to a merger or purchase and sale agreement, the evaluation of terms of the merger or purchase and sale agreement are used as an indicator of fair value.

During the year ended December 31, 2020, the Company recorded an unproved property impairment of $8.7 million related to anticipated leasehold expirations. During the year ended December 31, 2019, impairments were $5.0 million related to an office building lease. During the year ended December 31, 2018, impairments were $1,560.9 million primarily due to impairments of proved and unproved properties as a result of signing purchase and sale agreements for the Terminated Williston Basin Divestiture and the Uinta Basin Divestiture. For more information see Item 1A – Risk Factors in Part I and Note 1 – Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K.

We could be at risk for proved and unproved property and operating lease ROU asset impairments if current market conditions persist for an extended period of time, we experience negative changes in estimated reserve quantities, or the forward oil and gas prices decline from December 31, 2020 levels. The actual amount of impairment incurred, if any, for oil and gas properties will depend on a variety of factors including, but not limited to, subsequent forward price curve changes, the additional risk-adjusted value of probable and possible reserves associated with the properties, weighted-average cost of capital, operating cost estimates and future capital expenditure estimates.

Income Tax
The Tax Cuts and Jobs Act enacted in December 2017 changed several aspects of corporate taxation, including decreasing our federal corporate tax rate from 35% to 21%, limiting the amount of interest the Company could potentially deduct and eliminating the corporate AMT. The elimination of the corporate AMT allowed the Company to claim AMT refunds for AMT credits carried forward from prior tax years. The CARES Act enacted in March 2020 permitted the Company to carry back its NOL generated in 2018 and 2019, creating additional AMT credits, and accelerate all of its AMT refunds. The Company received $170.7 million of AMT credit refunds in 2020, inclusive of $5.6 million in interest income, during the year ended December 31, 2020, and $73.9 million of AMT credit refunds during the year ended December 31, 2019. As of December 31, 2020, the Company expects to receive an additional $61.6 million in AMT credit refunds due to additional NOL carrybacks relating to the 2018 and 2019 tax years. The NOL's that were generated are primarily due to the issuance of final regulations by the U.S. Department of Treasury in July 2020 that relate to the deductibility of interest expense. Of the $61.6 million in AMT credit refunds to be received, $30.7 million is shown in "Income tax receivable" and $30.9 million included in "Other noncurrent assets" on the Consolidated Balance Sheet as of December 31, 2020.

Multi-Well Pad Drilling and Completion
To reduce the costs of well location construction and rig mobilization and demobilization and to obtain other efficiencies, QEP utilizes multi-well pad drilling, where practical. For example, in the Permian Basin, QEP utilizes "tank-style" development, in which we simultaneously develop multiple subsurface targets by drilling and completing all wells in a given "tank" before any individual well is turned to production. We believe this approach maximizes the economic recovery of oil and condensate through the simultaneous development of multiple subsurface targets, while improving capital efficiency through shared surface facilities, which we believe will reduce per-unit operating costs and result in expanded operating margins and improve our returns on invested capital. Because wells drilled on a pad are not completed and brought into production until all wells on the pad are drilled and the drilling rig is moved from the location, multi-well pad drilling delays the completion of wells, the commencement of production from new wells, and may negatively affect production from existing offset wells. In addition, existing wells that offset new wells being completed by QEP or offset operators may need to be temporarily shut-in during the completion process. Such delays and well shut-ins have caused and may continue to cause volatility in QEP's quarterly operating results. In addition, delays in completion of wells may impact the timing of planned conversion of PUD reserves to proved developed reserves.

Uncertainties Related to Claims
QEP is currently subject to claims that could adversely impact QEP's liquidity, operating results and capital expenditures for a particular reporting period, including, but not limited to those described in Note 10 – Commitments and Contingencies, in Item 8 of Part II of this Annual Report on Form 10-K. Given the uncertainties involved in these matters, QEP is unable to predict the ultimate outcomes.

RESULTS OF OPERATIONS

Net Income

QEP generated net income during the year ended December 31, 2020 of $3.2 million, or $0.01 per diluted share, compared to a net loss of $97.3 million, or $0.41 per diluted share, in 2019. The increase in net income for the year ended December 31, 2020, compared to the year ended December 31, 2019, was primarily due to a $79.1 million decrease in unrealized derivative losses and a $36.9 million increase in income tax benefit.

See below for additional discussion regarding the components of net income (loss) for the years ended December 31, 2020 and 2019.

Adjusted EBITDA (Non-GAAP)

Management defines Adjusted EBITDA (a non-GAAP measure) as earnings before interest, income taxes, depreciation, depletion and amortization (EBITDA), adjusted to exclude changes in fair value of derivative contracts, exploration expenses, gains and losses from asset sales, impairment, gains or losses from early extinguishment of debt and certain other items. Management uses Adjusted EBITDA to evaluate QEP's financial performance and trends, make operating decisions and allocate resources. Management believes the measure is useful supplemental information for investors because it eliminates the impact of certain nonrecurring, non-cash and/or other items that management does not consider as indicative of QEP's performance from period to period. QEP's Adjusted EBITDA may be determined or calculated differently than similarly titled measures of other companies in our industry, which could reduce the usefulness of this non-GAAP financial measure when comparing our performance to that of other companies.

Below is a reconciliation of net income (loss) (a GAAP measure) to Adjusted EBITDA. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Net income (loss)	**$ 3.2**	$ (97.3)	$ (1,011.6)
Interest expense	**113.7**	128.1	149.4
Interest and other (income) expense	**(9.8)**	(4.7)	9.6
Income tax provision (benefit)	**(79.9)**	(43.0)	(317.4)
Depreciation, depletion and amortization	**574.0**	540.0	857.1
Unrealized (gains) losses on derivative contracts	**59.2**	138.3	(248.5)
Exploration expenses	**0.2**	0.1	0.3
Net (gain) loss from asset sales, inclusive of restructuring costs	**(1.2)**	(3.9)	(25.0)
Impairment	**8.7**	5.0	1,560.9
(Gain) loss from early extinguishment of debt	**(18.2)**	1.0	—
Adjusted EBITDA	**$ 649.9**	$ 663.6	$ 974.8

Adjusted EBITDA decreased to $649.9 million during the year ended December 31, 2020, compared to $663.6 million in 2019, primarily due to a $472.8 million decrease in oil and condensate, gas and NGL sales due to a 33% decrease in average field-level oil prices, and a 6% decrease in total oil equivalent production volumes, partially offset by a $327.0 million increase in realized derivative gains, a $62.8 million reduction in general and administrative expenses, a $41.3 million reduction in lease operating expenses and a $38.0 million reduction in production and property taxes.

Free Cash Flow (Non-GAAP)

Management defines Free Cash Flow as Adjusted EBITDA plus certain non-cash items that are included in Net Cash Provided by (Used in) Operating activities but excluded from Adjusted EBITDA less interest expense, excluding amortization of debt issuance costs and discounts, and accrued property, plant and equipment capital expenditures. Management believes that this measure is useful to management and investors for analysis of the Company's ability to repay debt, fund acquisitions or repurchase stock.

Free Cash Flow is not a measurement of our liquidity under GAAP and should not be considered as an alternative to Net Cash Provided by (Used in) Operating Activities as a measure of QEP’s liquidity. Free Cash Flow has limitations as an analytical tool and you should not consider it in isolation or as a substitute for analysis of QEP’s results as reported under GAAP, but rather as supplemental information to QEP’s business results. Free Cash Flow may not be comparable to similarly titled measures of other companies due to potential differences in methods of calculation and items or events being adjusted. In addition, other companies may use different measures to evaluate their performance, all of which could reduce the usefulness of Free Cash Flow as a tool for comparison.

Below is a reconciliation of Net Cash Provided by (Used in) Operating Activities (the most comparable GAAP measure) to Free Cash Flow. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP.

	Year Ended December 31,		
	2020	2019	2018
		(in millions)	
Net Cash Provided by (Used in) Operating Activities	**$ 673.2**	$ 566.9	$ 816.2
Exploration expense	**0.2**	0.1	0.3
Amortization of debt issuance costs and discounts	**(4.7)**	(5.4)	(5.4)
Interest expense	**113.7**	128.1	149.4
Unrealized (gains) losses on marketable securities	**3.2**	3.9	(1.2)
Interest and other (income) expense	**(9.8)**	(4.7)	9.6
Deferred income (taxes) benefit	**(110.6)**	(4.3)	247.6
Income tax provision (benefit)	**(79.9)**	(43.0)	(317.4)
Non-cash share-based compensation	**(12.4)**	(20.8)	(30.9)
Changes in operating assets and liabilities	**77.0**	42.8	106.6
Adjusted EBITDA	**649.9**	663.6	974.8
Non-cash share-based compensation	**12.4**	20.8	30.9
Interest expense, excluding amortization of debt issuance costs and discounts	**(109.0)**	(122.7)	(144.0)
Accrued property, plant and equipment capital expenditures	**(327.9)**	(571.5)	(1,176.6)
Free Cash Flow	**$ 225.4**	$ (9.8)	$ (314.9)

QEP generated Free Cash Flow of $225.4 million during the year ended December 31, 2020, compared to an outspend of $9.8 million during 2019. The increase in the Company's cash flow generation is primarily due to a $243.6 million decrease in accrued property, plant and equipment capital expenditures, primarily driven by suspending completion activity in March 2020 until the fourth quarter of 2020 and by peer leading drilling and completion costs in the Permian Basin. See above for additional discussion regarding the components of the change in Adjusted EBITDA in 2020 compared to 2019.

Revenue

The following table presents our revenues disaggregated by revenue source.

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
			(in millions)		
Oil and condensate, gas and NGL sales	**$ 714.6**	$ 1,187.4	$ 1,871.3	**$ (472.8)**	$ (683.9)
Transportation and processing costs in revenue[1]	**62.5**	54.9	55.0	**7.6**	(0.1)
Oil and condensate, gas and NGL sales, as adjusted[2]	**$ 777.1**	$ 1,242.3	$ 1,926.3	**$ (465.2)**	(684.0)
Oil and condensate sales	**$ 691.8**	$ 1,132.6	$ 1,422.4	**$ (440.8)**	$ (289.8)
Gas sales	**39.6**	52.4	393.0	**(12.8)**	(340.6)
NGL sales	**45.7**	57.3	110.9	**(11.6)**	(53.6)
Oil and condensate, gas and NGL sales, as adjusted[2]	**$ 777.1**	$ 1,242.3	$ 1,926.3	**$ (465.2)**	(684.0)

(1) Transportation and processing costs in the table above are not representative of total transportation and processing costs incurred for the years ended December 31, 2020, 2019 and 2018. Refer to the Operating Expenses section below for a reconciliation of total transportation and processing costs.

(2) Above is a reconciliation of Oil and condensate, gas and NGL sales (a GAAP measure) as presented on the Consolidated Statements of Operations to Oil and condensate, gas and NGL sales, as adjusted (a non-GAAP measure). Oil and condensate, gas and NGL sales, as adjusted excludes transportation and processing costs that are included as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Management removes these costs from "Oil and condensate, gas and NGL sales" included on the Consolidated Statements of Operations to reflect total revenue associated with its production prior to deducting any expenses. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total revenue generated from its wells for the period. This non-GAAP measure should be considered by the reader in addition to but not instead of, the financial measure prepared in accordance with GAAP. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Revenue, Volume and Price Variance Analysis

The following table shows volume and price related changes for each of QEP's adjusted production-related revenue categories for the year ended December 31, 2020 compared to the years ended December 31, 2019 and 2018:

	Oil and condensate	**Gas**	**NGL**	**Total**
Oil and condensate, gas and NGL sales, as adjusted		(in millions)		
Year ended December 31, 2018	$ 1,422.4	$ 393.0	$ 110.9	$ 1,926.3
Changes associated with volumes[1]	(141.0)	(300.3)	11.4	(429.9)
Changes associated with prices[2]	(148.8)	(40.3)	(65.0)	(254.1)
Year ended December 31, 2019	$ 1,132.6	$ 52.4	$ 57.3	$ 1,242.3
Changes associated with volumes[1]	**(96.5)**	**(1.1)**	**0.5**	**(97.1)**
Changes associated with prices[2]	**(344.3)**	**(11.7)**	**(12.1)**	**(368.1)**
Year ended December 31, 2020	**$ 691.8**	**$ 39.6**	**$ 45.7**	**$ 777.1**

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2020 and 2019, as compared to the years ended December 31, 2019 and 2018, by the average field-level price for the years ended December 31, 2019 and 2018, respectively.

(2) The revenue variance attributed to the change in price is calculated by multiplying the change in field-level prices from the years ended December 31, 2020 and 2019, as compared to the years ended December 31, 2019 and 2018, by the respective volumes for the years ended December 31, 2020 and 2019, respectively. Pricing changes are driven by changes in commodity field-level prices, excluding the impact from commodity derivatives.

A comparison of net realized average oil, gas and NGL prices, including the realized gains and losses on commodity derivative contracts, but excluding transportation and processing costs reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations, is provided in the following table:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
Oil (per bbl)					
Average field-level price	**$ 35.08**	$ 52.54	$ 59.43	**$ (17.46)**	$ (6.89)
Commodity derivative impact	**15.03**	(1.50)	(6.41)	**16.53**	4.91
Net realized price	**$ 50.11**	$ 51.04	$ 53.02	**$ (0.93)**	$ (1.98)
Gas (per Mcf)					
Average field-level price	**$ 1.22**	$ 1.58	$ 2.82	**$ (0.36)**	$ (1.24)
Commodity derivative impact	**(0.14)**	(0.08)	(0.04)	**(0.06)**	(0.04)
Net realized price	**$ 1.08**	$ 1.50	$ 2.78	**$ (0.42)**	$ (1.28)
NGL (per bbl)					
Average field-level price	**$ 8.82**	$ 11.15	$ 23.79	**$ (2.33)**	$ (12.64)
Commodity derivative impact	**—**	—	—	**—**	—
Net realized price	**$ 8.82**	$ 11.15	$ 23.79	**$ (2.33)**	$ (12.64)
Average net equivalent price (per Boe)					
Average field-level price	**$ 25.63**	$ 38.57	$ 37.15	**$ (12.94)**	$ 1.42
Commodity derivative impact	**9.63**	(1.09)	(3.06)	**10.72**	1.97
Net realized price	**$ 35.26**	$ 37.48	$ 34.09	**$ (2.22)**	$ 3.39

Oil and condensate sales. Oil and condensate sales were $691.8 million for the year ended December 31, 2020, a decrease of $440.8 million, or 39%, compared to 2019. This decrease was a result of a 33% decrease in average field-level prices and a 9% decrease in aggregate oil and condensate production volumes. The decrease in average field-level oil prices was driven by a decrease in average NYMEX WTI oil prices, partially offset by a $0.37 per bbl, or 8%, decrease in the basis differential relative to the average NYMEX WTI oil price in 2020 compared to 2019. The net realized price for 2020 was $50.11 per barrel, which included a $15.03 per barrel positive impact from our settled derivative contracts. The net realized price was 2% lower than the $51.04 per barrel net realized price in 2019 primarily due to the significant decline in the average field-level price, partially offset by the impact from our settled derivative contracts. The 9% decrease in oil and condensate production volumes was primarily driven by a decrease in production in the Permian and Williston basins due to reduced drilling and temporary suspension of completion activity in 2020 in response to market conditions.

Gas sales. Gas sales were $39.6 million for the year ended December 31, 2020, a decrease of $12.8 million, or 24%, compared to 2019 due to lower average field-level prices and lower gas production volumes. Average field-level prices decreased 23% compared to 2019, primarily driven by a decrease in average NYMEX-HH gas spot prices, partially offset by a $0.17 per Mcf, or 17%, decrease in regional basis differentials relative to the average NYMEX-HH gas price in comparable periods. Production volumes decreased 2% compared to 2019 primarily due to the reduction in completion activity in the Williston Basin in response to market conditions and the Haynesville Divestiture. These production decreases were partially offset by increased production in the Permian Basin.

NGL sales. NGL sales were $45.7 million for the year ended December 31, 2020, a decrease of $11.6 million, or 20%, compared to 2019, due to lower average field-level prices, partially offset by higher NGL production volumes. The 21% decrease in NGL prices in 2020 compared to 2019 was primarily driven by a decrease in propane, ethane and other NGL component prices. The 1% increase in NGL production volumes was primarily driven by increased production in the Williston basin, partially offset by decreased NGL recoveries in the Permian Basin.

Operating Expenses

The following table presents QEP's production costs on a unit of production basis:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
			(in millions)		
Lease operating expense	**$ 141.6**	$ 182.9	$ 263.1	**$ (41.3)**	$ (80.2)
Adjusted transportation and processing costs[1]	**116.9**	103.6	172.6	**13.3**	(69.0)
Production and property taxes	**57.9**	95.9	130.8	**(38.0)**	(34.9)
Total production costs	**$ 316.4**	$ 382.4	$ 566.5	**$ (66.0)**	$ (184.1)
			(per Boe)		
Lease operating expense	**$ 4.67**	$ 5.68	$ 5.07	**$ (1.01)**	$ 0.61
Adjusted transportation and processing costs[1]	**3.85**	3.22	3.33	**0.63**	(0.11)
Production and property taxes	**1.91**	2.98	2.52	**(1.07)**	0.46
Total production costs	**$ 10.43**	$ 11.88	$ 10.92	**$ (1.45)**	$ 0.96

(1) Below are reconciliations of transportation and processing costs (a GAAP measure) as presented on the Consolidated Statements of Operations and on a unit of production basis to adjusted transportation and processing costs (a non-GAAP measure). Adjusted transportation and processing costs includes transportation and processing costs that are reflected as part of "Oil and condensate, gas and NGL sales" on the Consolidated Statements of Operations. Management adds these costs together with transportation and processing costs reflected on the Consolidated Statements of Operations to reflect the total operating costs associated with its production. Management believes that this non-GAAP measure is useful supplemental information for investors as it is reflective of the total production costs required to operate the wells for the period. This non-GAAP measure should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
	(in millions)				
Transportation and processing costs, as presented	**$ 54.4**	$ 48.7	$ 117.6	**$ 5.7**	$ (68.9)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	**62.5**	54.9	55.0	**7.6**	(0.1)
Adjusted transportation and processing costs	**$ 116.9**	$ 103.6	$ 172.6	**$ 13.3**	$ (69.0)
	(per Boe)				
Transportation and processing costs, as presented	**$ 1.79**	$ 1.51	$ 2.27	**$ 0.28**	$ (0.76)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	**2.06**	1.70	1.06	**0.36**	0.64
Adjusted transportation and processing costs	**$ 3.85**	$ 3.21	$ 3.33	**$ 0.64**	$ (0.12)

Lease operating expense (LOE). QEP's LOE decreased $41.3 million during the year ended December 31, 2020 compared to 2019. The decrease in expense was driven by a decrease in workover activity in the Williston Basin and a decrease in maintenance and repairs expenses, power and fuel expenses, water disposal costs and chemical expenses in the Williston and Permian basins as a result of continuing efforts to reduce operating expenses.

During the year ended December 31, 2020, LOE decreased $1.01 per Boe, or 18%, compared to the year ended December 31, 2019, primarily due to continuing efforts to reduce operating expenses, despite decreased production in the Permian and Williston basins.

Adjusted transportation and processing costs. QEP's adjusted transportation and processing costs increased $13.3 million during the year ended December 31, 2020 compared to 2019. The increase in expense during 2020 was primarily attributable to increased gathering and processing rates in the Williston and Permian basins, partially offset by the recognition of $7.7 million of firm transportation expense during the year ended December 31, 2019 related to future obligations in an area in which the Company no longer has production obligations, the Haynesville Divestiture and decreased production in the Williston and Permian basins.

During the year ended December 31, 2020, adjusted transportation and processing costs increased $0.64 per Boe, or 20%, compared to the year ended December 31, 2019. The increase was primarily due to increased gathering and processing rates in the Williston and Permian basins, partially offset by the recognition of $7.7 million of firm transportation expense during the year ended December 31, 2019 related to future obligations in an area in which the Company no longer has production obligations.

Production and property taxes. QEP pays production taxes based on a percentage of field-level revenue. Production and property taxes decreased $38.0 million during 2020, primarily due to decreased revenues and the related production taxes in the Permian and Williston basins and decreased property tax expense in the Permian Basin.

During the year ended December 31, 2020, production and property taxes decreased $1.07 per Boe, or 36%, compared to the year ended December 31, 2019, primarily due to a decrease in revenues and the associated production taxes in the Permian and Williston basins and lower property tax expense in the Permian Basin.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $34.0 million during the year ended December 31, 2020, compared to 2019, primarily due to higher DD&A rates in the Williston and Permian basins, partially offset by a decrease in production in the Williston and Permian basins.

Impairment expense. During the year ended December 31, 2020, QEP recorded unproved property impairment charges of $8.7 million related to anticipated leasehold expirations. During the year ended December 31, 2019, QEP recorded impairment charges of $5.0 million which related to the impairment of an office building lease.

General and administrative (G&A) expense.

The following table presents detail about QEP's share-based compensation and deferred compensation components of QEP's total general and administrative expense, including the cash and non-cash components, for the years ended December 31, 2020 and 2019:

	Year Ended December 31,		
	2020	2019	Change
	(in millions)		
General and administrative (excluding merger costs and share-based and deferred compensation)	**$ 72.7**	$ 128.1	$ (55.4)
General and administrative merger costs[1]	**4.1**	—	4.1
General and administrative (share-based and deferred compensation):			
Cash share-based compensation[2]	**2.8**	4.6	(1.8)
Non-cash share-based compensation[1] [2]	**12.4**	20.8	(8.4)
Deferred compensation mark-to-market adjustments[3]	**1.0**	2.3	(1.3)
Total General and administrative	**$ 93.0**	$ 155.8	$ (62.8)
	(per Boe)		
General and administrative (excluding merger costs and share-based and deferred compensation)	**$ 2.40**	$ 3.98	$ (1.58)
General and administrative merger costs[1]	**0.14**	—	0.14
General and administrative (share-based and deferred compensation):			
Cash share-based compensation[2]	**0.09**	0.14	(0.05)
Non-cash share-based compensation[1] [2]	**0.41**	0.65	(0.24)
Deferred compensation mark-to-market adjustments[3]	**0.03**	0.07	(0.04)
Total General and administrative	**$ 3.07**	$ 4.84	$ (1.77)

(1) Total merger costs recognized in "General and administrative" expense during the year ended December 31, 2020 were $4.5 million, of which $4.1 million is presented as "General and administrative merger costs" and $0.4 million is presented as "Non-cash share-based compensation" as these costs relate to restricted share awards in which vesting was accelerated in accordance with the Merger Agreement.

(2) Cash share-based compensation represents restricted cash awards, performance share units and restricted share units recorded under the Company's Long-Term Incentive Plan (LTIP) and Cash Incentive Plan. Non-cash share-based compensation represents stock options and restricted share awards recorded under the Company's LTIP. Refer to Note 11 – Share-Based and Long-Term Compensation in Item 8 of Part II of this Annual Report on Form 10-K for more information on share-based compensation.

(3) Deferred compensation mark-to-market adjustments represent mark-to-market adjustments of the Company's non-qualified, unfunded deferred compensation wrap plan (Wrap Plan). Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information on the Wrap Plan.

During 2020, G&A expense decreased $62.8 million, or 40%, compared to 2019. During the years ended December 31, 2020 and 2019, QEP incurred $2.0 million and $50.1 million, respectively, in costs associated with the implementation of our strategic initiatives, of which $1.9 million and $43.4 million, respectively, was related to restructuring costs. Refer to Note 8 – Restructuring in Item 8 of Part II of this Annual Report on Form 10-K for more information on restructuring costs**.** Excluding these costs, QEP G&A expense decreased by $14.7 million, or 14%, primarily due to $19.6 million lower labor, benefits and other associated costs as a result of the reduction in our workforce, partially offset by $4.5 million of merger related costs associated with legal, financial advisory and accelerated restricted share awards costs.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the year ended December 31, 2020, QEP recognized a gain on sale of assets of $1.2 million, compared to a gain on sale of $3.9 million during the year ended December 31, 2019. The gain on sale of assets recognized in 2020 was primarily related to a net pre-tax gain on sale of $1.2 million from the divestiture of properties outside our main operating areas. The gain on sale of assets recognized in 2019 was primarily related to a net pre-tax gain on sale of $7.6 million from the divestiture of properties outside our main operating areas, partially offset by a $2.7 million pre-tax loss on the sale of the corporate aircraft and a pre-tax loss on sale, including restructuring costs, of $1.0 million related to the Haynesville Divestiture. Refer to Note 8 – Restructuring in Item 8, Part II of this Annual Report on Form 10-K for more information.

Non-Operating Expenses

Realized and unrealized gains (losses) on derivative contracts. Gains and losses on derivative contracts are comprised of both realized and unrealized gains and losses on QEP's commodity derivative contracts, which are marked-to-market each period. During the year ended December 31, 2020, gains on commodity derivative instruments were $232.7 million, of which $59.2 million were unrealized losses related to our production contracts and $291.9 million were realized gains. During 2019, losses on commodity derivative instruments were $173.4 million, of which $140.1 million were unrealized losses and $35.1 million were realized losses, partially offset by $1.8 million of unrealized gains related to the Haynesville Divestiture. Refer to Note 6 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Gain (loss) on early extinguishment of debt. Gain on early extinguishment of debt increased by $19.2 million during the year ended December 31, 2020, compared to 2019. The increase during the year ended December 31, 2020 was primarily due to a $27.1 million gain as a result of senior note repurchases, partially offset by a $7.4 million loss from the redemption of the 2021 Senior Notes and a $1.5 million loss associated with the write-off of non-cash deferred financing costs as part of amending the credit facility in June 2020 (Refer to Note 9 – Debt in Item 8 of Part II of this Annual Report on Form 10-K for more information).

Interest and other income (expense). Interest and other income (expense) increased by $5.1 million, or 109%, during the year ended December 31, 2020 compared to the year ended December 31, 2019. The increase in other income was primarily related to the receipt of $5.6 million of interest income associated with the receipt of the AMT credit refunds.

Interest expense. Interest expense decreased $14.4 million, or 11%, during the year ended December 31, 2020, compared to 2019. The decrease during the year ended December 31, 2020 was primarily related to decreased interest expense on senior notes due to debt repurchases and redemptions and decreased borrowings under the credit facility, partially offset by a reversal of accrued interest on the Company's uncertain tax position that expired in the fourth quarter of 2019.

Income tax (provision) benefit. Income tax benefit increased $36.9 million during the year ended December 31, 2020 compared to year ended December 31, 2019. The combined effective federal and state income tax rate was 104.2% during the year ended December 31, 2020, compared to 30.6% for the year ended December 31, 2019. The 2020 tax rate was driven higher than the statutory tax rate by the remeasurement of deferred taxes due to NOL carrybacks under the CARES Act to a year with a higher federal tax rate and a change in the Company's blended state rate. The 2019 tax rate was driven higher than the statutory tax rate by the re-measurement of QEP's deferred tax assets and liabilities at a lower blended state tax rate due to exiting the state of Louisiana and reversal of our uncertain tax position, partially offset by permanent difference items recognized in 2019 and an increase in the valuation allowance.

LIQUIDITY AND CAPITAL RESOURCES

QEP strives to maintain sufficient liquidity to ensure financial flexibility, withstand commodity price volatility, fund its development projects, operations and capital expenditures and return capital to shareholders. The Company utilizes derivative contracts to reduce the financial impact of commodity price volatility and provide a level of certainty to the Company's cash flows. QEP generally funds its operations and planned capital expenditures with cash flow from its operating activities, cash on hand and borrowings under its revolving credit facility, as needed. QEP also periodically accesses debt and equity markets and sells properties to enhance its liquidity. The Company expects that the annual generation of Free Cash Flow, cash on hand, AMT credit refund and, as needed, borrowings under its revolving credit facility, will be sufficient to fund its operations, capital expenditures, interest expense, and debt maturities, during the next 12 months. To the extent that the Company sells additional assets, the Company plans to use the proceeds to fund on-going operations, reduce debt and for general corporate purposes.

During the year ended December 31, 2020, QEP generated $225.4 million in Free Cash Flow, received cash proceeds of $170.7 million from the AMT credit refunds and received $13.8 million from the disposition of assets related to the divestiture of assets outside our main operating areas. The Company used the proceeds, as well as cash on hand, to repay $430.5 million in principal amount of outstanding debt and for general corporate purposes.

During the year ended December 31, 2020, QEP's Board approved a cash dividend of $0.02 per share of common stock in the first quarter of 2020 and paid $4.8 million in cash dividends in 2020. In an effort to preserve our liquidity, in March 2020, the Board subsequently suspended the payment of quarterly dividends indefinitely.

During the year ended December 31, 2019, QEP received cash proceeds from the disposition of assets of $678.9 million, of which $633.9 million related to the Haynesville Divestiture and $45.0 million related to the divestiture of other assets outside our main operating areas. The net cash proceeds were used to pay down long-term debt outstanding under QEP's revolving credit facility, redeem senior notes and for general corporate purposes.

During the year ended December 31, 2019, QEP's Board approved the reinstatement of a quarterly cash dividend of $0.02 per share of common stock and paid a total of $9.6 million in cash dividends in 2019.

As of December 31, 2020, the Company had $60.4 million in cash and cash equivalents, no borrowings outstanding and $14.1 million in letters of credit outstanding under the credit facility. The Company estimates, that as of December 31, 2020, it could incur additional indebtedness of approximately $750.0 million and incur up to $500.0 million of junior guaranteed indebtedness and remain in compliance with its financial covenants (as defined in the credit agreement). To the extent actual operating results, realized commodity prices or uses of cash differ from the Company's assumptions, QEP's liquidity could be adversely affected. Further, we may from time to time seek to retire, amend or restructure some or all of our outstanding debt or debt agreements through the use of cash purchases, exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Facility
In June 2020, QEP entered into the Eighth Amendment to its credit agreement, which, among other things, reduced the aggregate principal amount of commitments to $850.0 million, requires the Company's material subsidiaries to guarantee the obligations under the credit agreement, including certain swap obligations and modified the leverage ratio and present value financial covenants, such that they only pertain to net priority guaranteed debt (primarily consisting of borrowings under the credit facility and letters of credit). The amended credit agreement also provides the ability to use up to $500.0 million of loan proceeds to repurchase outstanding senior notes, provides the ability to issue subsidiary guarantees of up to $500.0 million of unsecured debt, with such guarantees being subordinated to the obligations under the credit agreement, and may limit the Company’s ability to make certain restricted payments, including dividends. The amended credit agreement, which matures on September 1, 2022, provides for borrowings at short-term interest rates and contains customary covenants and restrictions and contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a minimum liquidity amount of at least $100.0 million (ii) a net priority guaranteed leverage ratio under which net priority guaranteed debt may not exceed 2.50 times consolidated EBITDAX (as defined in the credit agreement), and (iii) a present value coverage ratio under which the present value of the Company's proved reserves must exceed net priority guaranteed debt by at least 1.50 times. As of December 31, 2020 and 2019, QEP was in compliance with the covenants under the credit agreement. During the year ended December 31, 2020, the Company recorded a $1.5 million loss associated with the write-off of non-cash deferred financing costs as part of amending the credit facility and recorded the loss within "Gain (loss) from early extinguishment of debt" on the statements of operations.

During the year ended December 31, 2020, QEP's weighted-average interest rate on borrowings from its credit facility was 2.60%. As of December 31, 2020, QEP had no borrowings outstanding and $14.1 million in letters of credit outstanding under the credit facility. As of December 31, 2019, QEP had no borrowings outstanding and $2.9 million in letters of credit outstanding under the credit facility. As of February 17, 2021, QEP had no borrowings outstanding and had $14.1 million of letters of credit outstanding under the credit facility.

Senior Notes
The Company's senior notes outstanding as of December 31, 2020, totaled $1,601.9 million principal amount and are comprised of three issuances as follows:

- $465.1 million 5.375% Senior Notes due October 2022;
- $636.8 million 5.25% Senior Notes due May 2023; and
- $500.0 million 5.625% Senior Notes due March 2026.

During the year ended December 31, 2020, QEP repurchased, at a discount, $107.1 million in principal amount of its 6.875% Senior Notes due March 1, 2021, $34.9 million in principal amount of its 5.375% Senior Notes due October 1, 2022, and $13.2 million in principal amount of its 5.25% Senior Notes due May 1, 2023, resulting in a $27.1 million gain from early extinguishment of debt. In addition, QEP redeemed the remaining $275.3 million in principal amount of its 6.875% Senior Notes due March 1, 2021, resulting in a loss on early extinguishment of debt of $7.4 million. In total, during the year ended December 31, 2020, the Company recorded a $19.7 million gain in "Gain (loss) from early extinguishment of debt" in the statements of operations related to the redemption and repurchase of senior notes.

Cash Flow from Operating Activities

Cash flows from operating activities are primarily affected by oil and condensate, gas and NGL production volumes and commodity prices (including the effects of settlements of the Company's derivative contracts), cash related operating expenses and by changes in working capital. QEP typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated future oil and condensate and gas production for the next 12 to 24 months.

Net cash provided by (used in) operating activities is presented below:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
			(in millions)		
Net income (loss)	**$ 3.2**	(97.3)	$ (1,011.6)	**$ 100.5**	$ 914.3
Non-cash adjustments to net income (loss)	**747.0**	707.0	1,934.4	**40.0**	(1,227.4)
Changes in operating assets and liabilities	**(77.0)**	(42.8)	(106.6)	**(34.2)**	63.8
Net cash provided by (used in) operating activities	**$ 673.2**	$ 566.9	$ 816.2	**$ 106.3**	$ (249.3)

Net cash provided by operating activities during the year ended December 31, 2020, increased $106.3 million compared to 2019, which was due to a $100.5 million increase in net income and a $40.0 million increase in non-cash adjustments to net income, partially offset by a $34.2 million increase in cash from operating assets and liabilities. During the year ended December 31, 2020, non-cash adjustments to net income primarily included DD&A expense of $574.0 million, deferred income taxes of $110.6 million and unrealized losses on derivative contracts of $59.2 million. The change in operating assets and liabilities of $77.0 million was primarily due to a decrease in accounts payable and accrued expenses of $42.4 million and an increase in other asset balances of $27.9 million.

Net cash provided by operating activities during the year ended December 31, 2019, decreased $249.3 million compared to 2018, which was due to a $1,227.4 million decrease in non-cash adjustments to the net loss, partially offset by a $914.3 million decrease in the net loss and a $63.8 million increase in cash from operating assets and liabilities. During the year ended December 31, 2019, non-cash adjustments to the net loss primarily included DD&A expense of $540.0 million, unrealized losses on derivative contracts of $138.3 million, share-based compensation expense of $20.8 million and deferred income taxes of $4.3 million. The change in operating assets and liabilities of $42.8 million was primarily due to a decrease in long-term tax payables and post-retirement benefit obligations of $45.2 million and a decrease in accounts payable and accrued expenses of $40.4 million, partially offset by a decrease in accrued income taxes receivable of $38.4 million.

Cash Flow from Investing Activities

A comparison of capital expenditures for the years ended December 31, 2020, 2019 and 2018, are presented in the table below:

	Year Ended December 31,			Change	
	2020	2019	2018	**2020 vs 2019**	2019 vs 2018
			(in millions)		
Property acquisitions	**$ 4.1**	$ 3.5	$ 65.6	**$ 0.6**	$ (62.1)
Property, plant and equipment capital expenditures	**327.9**	571.5	1,176.6	**(243.6)**	(605.1)
Total accrued capital expenditures	**332.0**	575.0	1,242.2	**(243.0)**	(667.2)
Change in accruals and other non-cash adjustments	**25.6**	(8.8)	57.5	**34.4**	(66.3)
Total cash capital expenditures	**$ 357.6**	$ 566.2	$ 1,299.7	**$ (208.6)**	$ (733.5)

During the year ended December 31, 2020, on an accrual basis, the Company invested $327.9 million on property, plant and equipment capital expenditures (which excludes property acquisitions), a decrease of $243.6 million compared to 2019. In 2020, QEP's primary capital expenditures included $249.1 million in the Permian Basin (including midstream infrastructure of $10.3 million, primarily related to oil and gas gathering and water handling) and $71.5 million in the Williston Basin. The 43% reduction in capital expenditures in 2020 compared to 2019 is primarily a result of the Company's decision to suspend completion activity until the fourth quarter of 2020 in the Permian Basin in order to proactively manage cash flow and preserve liquidity as a result of the COVID-19 pandemic and market conditions.

During the year ended December 31, 2019, on an accrual basis, the Company invested $571.5 million on property, plant and equipment expenditures, excluding property acquisitions, a decrease of $605.1 million compared to 2018. In 2019, QEP's primary capital expenditures included $477.1 million in the Permian Basin (including midstream infrastructure of $41.8 million, primarily related to oil and gas gathering and water handling), and $94.2 million in the Williston Basin. The reduction in capital expenditures from 2019 to 2018 is a result of the Company's focus on capital efficiency and its desire to generate Free Cash Flow, causing a 45% reduction in Permian and Williston basin capital expenditures, and the Haynesville and Uinta basin divestitures.

QEP intends to fund capital expenditures (excluding property acquisitions) with cash on hand, cash flow from operating activities and, as needed, borrowings under our revolving credit facility. The aggregate levels of capital expenditures for 2021 and the allocation of those expenditures are dependent on a variety of factors, including the continued impact on the market due to the COVID-19 pandemic and OPEC actions, oil, gas and NGL prices, industry conditions, changes in management's business assessments as to where QEP's capital can be most profitably deployed, drilling results, the extent to which properties or working interests are acquired or divested and the availability of capital resources to fund the expenditures. Accordingly, the actual levels of capital expenditures and the allocation of those expenditures may vary materially from QEP's estimates.

Cash Flow from Financing Activities

During the year ended December 31, 2020, net cash used in financing activities was $433.5 million compared to net cash used in financing activities of $511.3 million during the year ended December 31, 2019. During the year ended December 31, 2020, QEP used $410.3 million of cash to repurchase and redeem senior notes, which were due in 2021, 2022 and 2023, decreased checks outstanding in excess of cash by $16.1 million and paid $4.8 million in dividends. In addition, QEP had treasury stock repurchases of $1.7 million related to the settlement of employment tax and related benefit withholding obligations arising from the vesting of restricted share grants. As of December 31, 2020, long-term debt consisted of $1,591.3 million total debt, of which $1,601.9 million was senior notes and $10.6 million of net original issue discount and unamortized debt issuance costs.

During the year ended December 31, 2019, net cash used in financing activities was $511.3 million compared to net cash provided by financing activities of $244.6 million during the year ended December 31, 2018. During the year ended December 31, 2019, QEP made repayments under its credit facility of $486.0 million, repaid an aggregate $66.9 million of its senior notes, which were due in 2020 and 2021, and paid $9.6 million in dividends. These cash outflows were offset by borrowings under its credit facility of $56.1 million. In addition, QEP had treasury stock repurchases of $7.6 million related to the settlement of employment tax and related benefit withholding obligations arising from the vesting of restricted share grants. During 2019, QEP had a decrease in checks outstanding in excess of cash balances of $3.7 million. As of December 31, 2019, long-term debt consisted of $2,015.6 million total debt, of which $2,032.4 million was senior notes and $16.8 million of net original issue discount and unamortized debt issuance costs.

Off-Balance Sheet Arrangements

QEP may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. At December 31, 2020, the Company's material off-balance sheet arrangements included drilling, gathering, processing and firm transportation and undrawn letters of credit. The Company expects to enter into similar contractual arrangements in the future in order to support the Company's business plans. There are no other off-balance sheet arrangements that have or are reasonably likely to have a current or future material effect on QEP's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources. See "Contractual Obligations" below for more information regarding QEP's off-balance sheet arrangements.

Contractual Obligations

In the course of ordinary business activities, QEP enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual obligations and other commitments as of December 31, 2020:

	Payments Due by Year[1]						
	Total	2021	2022	2023	2024	2025	After 2025
	(in millions)						
Long-term debt	$ 1,601.9	$ —	$ 465.1	$ 636.8	$ —	$ —	$ 500.0
Interest on fixed-rate, long-term debt[2]	271.9	89.1	82.4	39.5	28.1	28.1	4.7
Drilling contracts	1.6	1.6	—	—	—	—	—
Gathering, processing, firm transportation and other	74.9	26.4	22.4	12.2	6.9	4.9	2.1
Asset retirement obligations[3]	102.7	8.4	2.3	1.7	2.1	2.3	85.9
Building, compressor, generator and equipment operating leases	59.7	24.9	17.2	11.5	2.4	0.8	2.9
Total	$ 2,112.7	$ 150.4	$ 589.4	$ 701.7	$ 39.5	$ 36.1	$ 595.6

(1) This table excludes the Company's benefit plan liabilities as future payment dates are unknown. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.
(2) Excludes variable rate debt interest payments and commitment fees related to the Company's revolving credit facility.
(3) These future obligations are discounted estimates of future expenditures based on expected settlement dates. Refer to Note 4 – Asset Retirement Obligations in Item 8 of Part II in this Annual Report on Form 10-K for more information.

Impact of Inflation/Deflation and Pricing

All of QEP's transactions are denominated in U.S. dollars. Typically, as prices for oil and gas increase, associated costs rise. Conversely, as oil and gas prices decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to declining commodity prices. Historically, field-level prices received for QEP's oil and gas production have been volatile. During the year ended December 31, 2020, commodity prices decreased from the previous year and were negatively impacted by a variety of factors, including the COVID-19 pandemic and related shut-down of various sectors of the global economy, as well as the delay of an agreement in early 2020 on production levels by members of the OPEC and other oil producing countries. During the year ended December 31, 2019, commodity prices decreased from the previous year. During the year ended December 31, 2018, commodity prices increased from the previous year. Changes in commodity prices impact QEP's revenues, estimates of reserves, assessments of any impairment of oil and gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect QEP's ability to raise capital, borrow money, and retain personnel.

Critical Accounting Estimates

QEP's significant accounting policies are described in Note 1 – Summary of Significant Accounting Policies, in Item 8 of Part II of this Annual Report on Form 10-K. The Company's Consolidated Financial Statements are prepared in accordance with GAAP. The preparation of consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. The following is a discussion of the accounting policies, estimates and judgments that management believes are most significant in the application of GAAP used in the preparation of the Company's consolidated financial statements. These accounting policies, among others, may involve a high degree of complexity and judgment on the part of management. Further, these estimates and other factors, including those outside of the Company's control, such as the impact of sustained lower commodity prices, could have significant adverse impact to the Company's financial condition, results of operations and cash flows.

Oil and condensate, gas and NGL Reserves
One of the most significant estimates the Company makes is the estimate of proved oil and condensate, gas and NGL reserves. Oil and condensate, gas and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, timing to initiate production for proved undeveloped reserves due to sequence of drilling, completing and/or recompleting wells and constraints set by regulatory bodies. Additionally, data for a given field could change substantially due to development activity, production history, projected future production, changes in reservoir performance, pipeline capacity and/or operating conditions, market demand, capital expenditures and remediation costs. The subjective judgments and variances in data for various fields make these estimates less precise than other estimates included in the consolidated financial statements and related disclosures.

Estimates of proved oil and condensate, gas and NGL reserves significantly affect the Company's DD&A expense. For example, if estimates of proved reserves decline, the Company's DD&A rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause QEP to perform an impairment analysis to determine if the carrying value of our oil and gas properties exceeds fair value, which could result in an impairment charge that would reduce earnings. See "Impairment of Long-Lived Assets" below.

QEP engages independent reservoir engineering consultants to prepare estimates of the proved oil and condensate, gas and NGL reserves. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development drilling information becomes available. Refer to Note 15 – Supplemental Oil and Gas Information (unaudited) in Item 8 of Part II of this Annual Report on Form 10-K.

Successful Efforts Accounting for Oil and Gas Operations
The Company follows the successful efforts method of accounting for oil and gas property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, delay rentals and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production DD&A rate would be significantly affected. Capitalized costs of unproved properties are reclassified to proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Impairment of Long-Lived Assets
Proved oil and gas properties are evaluated on a field-by-field basis for impairment. Other property, plant and equipment are evaluated on a specific asset basis or in groups of similar assets, as applicable. When an indicator of impairment, or a "triggering event," is identified, the Company uses a cash flow model to assess its proved properties and operating lease ROU assets for impairment. Triggering events could include, but are not limited to, a reduction of oil and condensate, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues, potential disposition of assets, merger transactions and declines in oil, gas and NGL prices. When a triggering event is identified, the undiscounted future net cash flows of an evaluated asset are compared to the asset's carrying value. Cash flow estimates require forecasts and significant estimates and assumptions for many years into the future for a variety of factors, including estimates of future production, future oil and gas prices, future operating costs, future development costs and our five-year development plan. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. If the asset's carrying value exceeds the related undiscounted net cash flows, fair value of the evaluated asset is estimated using a discounted cash flow approach. The signing of a merger or purchase and sale agreement could cause the Company to evaluate for, or recognize, an impairment of proved properties. For assets subject to a merger or purchase and sale agreement, the evaluation of terms of the merger or purchase and sale agreement are used as an indicator of fair value. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach whereas the likelihood of possible outcomes is taken into consideration. As of March 31, 2020, December 31, 2020 and December 31, 2019, the Company performed an assessment of recoverability and determined that the carrying value of proved properties was less than the respective future undiscounted cash flows, therefore recording no impairment. In our evaluation of recoverability as of December 31, 2020 we considered the estimated future pricing used by management in evaluating and entering into the Merger Agreement. During the year ended December 31, 2018, QEP recorded impairment expense of $1,524.6 million related to proved properties, which was primarily the result of signing purchase and sale agreements related to the Terminated Williston Basin Divestiture and the Uinta Basin Divestiture.

During the year ended December 31, 2019, the Company recorded impairments of $5.0 million related to an office building lease.

Unproved properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term. During the year ended December 31, 2020, QEP recorded unproved property impairment charges of $8.7 million related to anticipated leasehold expirations. During the year ended December 31, 2019, the Company recorded no impairment of unproved properties. During the year ended December 31, 2018, QEP recorded $36.3 million related to its unproved properties, which primarily resulted from unproved leasehold acreage in the Williston and Uinta basins.

Income Taxes

The amount of income taxes recorded by QEP requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. QEP has recognized deferred tax assets and liabilities for temporary differences, operating losses and tax credit carryforwards. QEP routinely assesses the realizability of its deferred tax assets and reduces such assets by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. QEP routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts. The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future, based on the impact of tax audits, changes in legislation and resolution of pending or future tax matters. Refer to Note 13 – Income Taxes in Item 8 of Part II of this Annual Report on Form 10-K for more information.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

QEP's primary market risks arise from changes in the market price for oil, gas and NGL and volatility in interest rates. These risks can affect revenues and cash flows from operating, investing and financing activities. Commodity prices have historically been volatile and are subject to wide fluctuations in response to relatively minor changes in supply and demand. If commodity prices fluctuate significantly, revenues and cash flow may significantly decrease or increase. QEP has long-term contracts for pipeline capacity and is obligated to pay for transportation services with no guarantee that it will be able to fully utilize the contractual capacity of these transportation commitments. In addition, additional non-cash impairment expense of the Company's oil and gas properties may be required if future oil and gas commodity prices experience a significant decline. Furthermore, the Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. To partially manage the Company's exposure to these risks, QEP enters into commodity derivative contracts in the form of fixed-price and basis swaps and collars to manage commodity price risk.

Commodity Price Risk Management

QEP uses commodity derivative instruments in the normal course of business to reduce the risk of adverse commodity price movements. However, these arrangements typically limit future gains from favorable price movements. The types of commodity derivative instruments currently utilized by the Company are fixed-price and basis swaps and collars. The volume of commodity derivative instruments utilized by the Company may vary from year to year based on QEP's forecasted production. The Company's current derivative instruments do not have margin requirements or collateral provisions that would require payments prior to the scheduled cash settlement dates. As of December 31, 2020, QEP held commodity price derivative contracts, excluding basis swaps, totaling 14.9 million barrels of oil and 27.4 MMbtu of gas. As of December 31, 2019, QEP held commodity price derivative contracts, excluding basis swaps, totaling 17.5 million barrels of oil and had no gas commodity price derivative contracts.

The following table presents QEP's volumes and average prices for its derivative positions as of February 17, 2021. Refer to Note 6 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for open derivative positions as of December 31, 2020.

Production Commodity Derivative Swaps

Year	Index	Total Volumes		Average Swap Price per Unit
		(in millions)		
Oil sales		(bbls)		($/bbl)
2021 (February - June)	NYMEX WTI	6.1	$	44.53
2021 (July - December)	NYMEX WTI	6.3	$	42.64
2022 (January - June)	NYMEX WTI	0.2	$	45.00
Gas sales		(MMbtu)		($/MMbtu)
2021	IF WAHA	16.7	$	1.92
2021	NYMEX HH	8.4	$	2.44

Production Commodity Derivative Basis Swaps

Year	Index	Basis	Total Volumes		Weighted-Average Differential
			(in millions)		
Oil sales			(bbls)		($/bbl)
2021	NYMEX WTI	Argus WTI Midland	5.3	$	0.88
2021	NYMEX CMA	Argus WTI	1.4	$	0.00
2021	NYMEX WTI	NYMEX Roll	1.7	$	(0.05)

Production Commodity Costless Oil Collars

Year	Index	Total Volumes		Average Price Floor		Average Price Ceiling
		(in millions)				
		(bbls)		($/bbl)		($/bbl)
2021 (February - June)	NYMEX WTI	0.6	$	42.80	$	51.49
2021 (July - December)	NYMEX WTI	0.8	$	40.68	$	50.21

Changes in the fair value of derivative contracts from December 31, 2019 to December 31, 2020, are presented below:

		Commodity derivative contracts
		(in millions)
Net fair value of oil and gas derivative contracts outstanding at December 31, 2019	$	(17.5)
Contracts settled		**(291.9)**
Change in oil and gas prices on futures markets		**323.6**
Contracts added		**(90.9)**
Net fair value of oil and gas derivative contracts outstanding at December 31, 2020	**$**	**(76.7)**

The following table shows the sensitivity of the fair value of oil and gas derivative contracts to changes in the market price of oil, gas and basis differentials:

		December 31, 2020
		(in millions)
Net fair value – asset (liability)	**$**	**(76.7)**
Fair value if market prices of oil, gas and basis differentials decline by 10%	**$**	**(69.1)**
Fair value if market prices of oil, gas and basis differentials increase by 10%	**$**	**(84.4)**

Utilizing the actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these instruments by $7.7 million, while a 10% decrease in underlying commodity prices would increase the fair value of these instruments by $7.6 million as of December 31, 2020. However, a gain or loss eventually would be offset by the actual sales value of the physical production covered by the derivative instruments. For more information regarding the Company's commodity derivative transactions, refer to Note 6 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K.

Interest Rate Risk Management

The Company's ability to borrow and the rates offered by lenders can be adversely affected by illiquid credit markets and the Company's credit rating, as described in the Risk Factors, in Item 1A of Part I of this Annual Report on Form 10-K. The Company's revolving credit facility has a floating interest rate, which exposes QEP to interest rate risk if QEP has borrowings outstanding. As of December 31, 2020 and 2019, QEP had no borrowings outstanding under its revolving credit facility. If interest rates were to increase or decrease 10% during the year ended December 31, 2020, at our average level of borrowing for those same periods, the Company's interest expense would increase or decrease by approximately $1.1 million, or less than 1% of total interest expense. The Company's total outstanding debt of $1,601.9 million is senior notes with fixed interest rates; therefore, it is not affected by interest rate movements. For more information regarding the Company's debt instruments, refer to Note 9 – Debt in Item 8 of Part II of this Annual Report on Form 10-K.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of QEP Resources, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of QEP Resources, Inc. and subsidiaries (the "Company") as of December 31, 2020, the related consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the year ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020, and the results of its operations and its cash flows for the year ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2021, expressed an unqualified opinion on the Company's internal control over financial reporting.

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 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 the financial statements are free of material misstatement, whether due to error or fraud. Our audit 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 audit 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 audit provides 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 a critical audit matter does not alter in any way our opinion on the 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.

Proved Oil and Gas Properties — Oil and Gas Reserve Quantities and Related Future Cash Flow Estimates — Refer to Notes 1 and 5 to the consolidated financial statements

Critical Audit Matter Description

The Company's proved oil and gas properties are depleted on a field-by-field basis using units-of-production method, and when an indication of impairment is identified, are evaluated for impairment by comparison of the evaluated asset's carrying value to the estimated undiscounted future net cash flows derived in part from the underlying oil and gas reserves. As of March 31, 2020 and December 31, 2020, the Company performed an assessment of recoverability of its proved oil and gas properties. In each instance, the evaluated assets' carrying value was less than the respective future undiscounted net cash flows; therefore, the Company recorded no impairment. The development of the Company's oil and gas reserve quantities and the related future net cash flows used to evaluate proved oil and gas properties for impairment requires management to make significant estimates and assumptions, including those related to management's five-year development plan and future oil and gas prices. As of December 31, 2020, 55% of the estimated proved oil and gas reserves were attributable to proved undeveloped reserves.

The Company engages an independent oil and gas reserve engineer to estimate oil and natural gas quantities in accordance with the SEC's Regulation S-X and ASC 932 as amended. Changes in these assumptions or engineering data could have a significant impact on the amount of depletion and any proved oil and gas property impairment. The proved oil and natural gas properties balance was $4,213.2 million as of December 31, 2020, net of accumulated depreciation, depletion and impairment.

Given the significant judgments made by management, performing audit procedures to evaluate the Company's oil and gas reserve quantities and the related net cash flows, including management's estimates and assumptions related to its five-year development plan and future oil and gas prices, required a high degree of auditor judgment and an increased extent of effort, including the need to involve our fair value specialists.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to management’s significant judgments and assumptions related to oil and gas reserves quantities and estimates of future net cash flows included the following, among others:

- We tested the operating effectiveness of controls related to the Company’s estimation of oil and gas reserves quantities and the related future net cash flows, including controls relating to management’s five-year development plan, and forecasted future oil and gas prices.
- We evaluated the reasonableness of management’s five-year development plan by considering:
  - Historical conversions of proved undeveloped oil and gas reserves into proved developed oil and gas reserves.
  - Working capital and future cash flows to support development of proved undeveloped reserves into proved developed oil and gas reserves.
  - Historical and projected development pace and rig utilization.
  - Dates that current proved undeveloped locations were originally identified as proved undeveloped locations.
  - Internal communications to management and the Board of Directors.
  - Permits and approval for expenditures.
  - Forecasted information by the Northern and Southern Regions included in Company press releases as well as in analyst and industry reports for the Company and certain of its peer companies.
- With the assistance of our fair value specialists, we assessed management’s estimated future oil and gas prices by:
  - Understanding the methodology used by management for development of the future oil and gas prices and comparing the estimated prices to an independently determined range of future prices, including published forward pricing indices and third-party industry sources.
  - Evaluating the forecasted realized price differentials incorporated in the future oil and natural gas prices against those historically realized.
  - Considering pricing data utilized by management in contemplated transactions with third parties.
- We evaluated the experience, qualifications and objectivity of management’s expert, an independent oil and gas reserve engineer, including the methodologies used to estimate oil and gas reserves quantities, and the related future net cash flows.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 24, 2021

We have served as the Company's auditor since 2020.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of QEP Resources, Inc.

Opinion on the Financial Statements

We have audited the consolidated balance sheets of QEP Resources, Inc. and its subsidiaries (the “Company”) as of December 31, 2019, and the related consolidated statements of operations, comprehensive income (loss), equity, and cash flows for each of the two years in the period ended December 31, 2019, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 of these consolidated financial statements 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 26, 2020

We served as the Company's auditor from 2012 to 2020.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2020	2019	2018
REVENUES	(in millions, except per share amounts)		
Oil and condensate, gas and NGL sales	**$ 714.6**	$ 1,187.4	$ 1,871.3
Other revenues	**2.4**	7.9	12.5
Purchased oil and gas sales	**7.4**	10.9	48.8
Total Revenues	**724.4**	1,206.2	1,932.6
OPERATING EXPENSES			
Purchased oil and gas expense	**8.7**	11.0	51.0
Lease operating expense	**141.6**	182.9	263.1
Transportation and processing costs	**54.4**	48.7	117.6
Gathering and other expense	**10.8**	13.2	15.5
General and administrative	**93.0**	155.8	221.7
Production and property taxes	**57.9**	95.9	130.8
Depreciation, depletion and amortization	**574.0**	540.0	857.1
Exploration expenses	**0.2**	0.1	0.3
Impairment	**8.7**	5.0	1,560.9
Total Operating Expenses	**949.3**	1,052.6	3,218.0
Net gain (loss) from asset sales, inclusive of restructuring costs	**1.2**	3.9	25.0
OPERATING INCOME (LOSS)	**(223.7)**	157.5	(1,260.4)
Realized and unrealized gains (losses) on derivative contracts (Note 6)	**232.7**	(173.4)	90.4
Interest and other income (expense)	**9.8**	4.7	(9.6)
Gain (loss) from early extinguishment of debt	**18.2**	(1.0)	—
Interest expense	**(113.7)**	(128.1)	(149.4)
INCOME (LOSS) BEFORE INCOME TAXES	**(76.7)**	(140.3)	(1,329.0)
Income tax (provision) benefit	**79.9**	43.0	317.4
NET INCOME (LOSS)	**$ 3.2**	$ (97.3)	$ (1,011.6)
Earnings (loss) per common share			
Basic	**$ 0.01**	$ (0.41)	$ (4.25)
Diluted	**$ 0.01**	$ (0.41)	$ (4.25)
Weighted-average common shares outstanding			
Used in basic calculation	**241.6**	237.7	237.9
Used in diluted calculation	**241.6**	237.7	237.9

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Net income (loss)	**$ 3.2**	$ (97.3)	$ (1,011.6)
Other comprehensive income, net of tax:			
Pension and other postretirement plans adjustments:			
Current period prior service cost[(1)]	**—**	—	(0.1)
Current period net actuarial gain (loss)[(2)]	**(1.8)**	1.1	(4.2)
Amortization of prior service cost[(3)]	**—**	(0.3)	0.4
Amortization of net actuarial (gain) loss[(4)]	**0.7**	0.4	0.6
Net curtailment and settlement cost incurred[(5)]	**0.8**	0.6	0.1
Other comprehensive income (loss)	**(0.3)**	1.8	(3.2)
Comprehensive income (loss)	**$ 2.9**	$ (95.5)	$ (1,014.8)

(1) Presented net of income tax benefit of $0.1 million for the year ended December 31, 2018.
(2) Presented net of income tax benefit of $0.5 million for the year ended December 31, 2020, net of income tax expense of $0.3 million for the year ended December 31, 2019 and net of income tax benefit of $1.3 million for the year ended December 31, 2018.
(3) Presented net of income tax benefit of $0.1 million for the year ended December 31, 2019 and net of income tax expense of $0.1 million for the year ended December 31, 2018.
(4) Presented net of income tax expense of $0.2 million, $0.1 million and $0.2 million for the years ended December 31, 2020, 2019 and 2018, respectively.
(5) Presented net of income tax expense $0.2 million and $0.2 million for the years ended December 31, 2020 and 2019, respectively.

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2020	December 31, 2019
ASSETS	(in millions)	
Current Assets		
Cash and cash equivalents	$ 60.4	$ 166.3
Accounts receivable, net	89.1	108.4
Income tax receivable	33.2	37.4
Fair value of derivative contracts	—	1.5
Prepaid expenses	14.1	11.4
Other current assets	0.2	0.2
Total Current Assets	197.0	325.2
Property, Plant and Equipment (successful efforts method for oil and gas properties)		
Proved properties	9,941.2	9,574.9
Unproved properties	454.4	599.1
Gathering and other	167.3	164.2
Materials and supplies	18.7	15.6
Total Property, Plant and Equipment	10,581.6	10,353.8
Less Accumulated Depreciation, Depletion and Amortization		
Exploration and production	5,728.0	5,250.5
Gathering and other	70.7	61.0
Total Accumulated Depreciation, Depletion and Amortization	5,798.7	5,311.5
Net Property, Plant and Equipment	4,782.9	5,042.3
Fair value of derivative contracts	—	0.2
Operating lease right-of-use assets, net	48.0	56.8
Other noncurrent assets	86.3	53.3
TOTAL ASSETS	$ 5,114.2	$ 5,477.8
LIABILITIES AND EQUITY		
Current Liabilities		
Checks outstanding in excess of cash balances	$ 2.1	$ 18.3
Accounts payable and accrued expenses	159.3	227.2
Production and property taxes	12.2	18.9
Interest payable	21.5	31.0
Fair value of derivative contracts	76.4	18.7
Current operating lease liabilities	21.7	18.0
Asset retirement obligations	6.4	6.0
Total Current Liabilities	299.6	338.1
Long-term debt	1,591.3	2,015.6
Deferred income taxes	385.2	274.5
Asset retirement obligations	96.3	94.9
Fair value of derivative contracts	0.3	0.5
Operating lease liabilities	31.3	44.8
Other long-term liabilities	40.0	48.8
Commitments and Contingencies (Note 10)		
EQUITY		
Common stock - par value $0.01 per share; 500.0 million shares authorized; 248.0 million and 242.1 million shares issued, respectively	2.5	2.4
Treasury stock - 5.4 million and 4.4 million shares, respectively	(57.6)	(55.4)
Additional paid-in capital	1,470.1	1,456.5
Retained earnings	1,268.0	1,269.6
Accumulated other comprehensive income (loss)	(12.8)	(12.5)
Total Common Shareholders' Equity	2,670.2	2,660.6
TOTAL LIABILITIES AND EQUITY	$ 5,114.2	$ 5,477.8

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income(Loss)	Total
	Shares	Amount	Shares	Amount				
	(in millions)							
Balance at December 31, 2017	243.0	$ 2.4	(2.0)	$ (34.2)	$ 1,398.2	$ 2,442.6	$ (11.1)	$ 3,797.9
Net income (loss)	—	—	—	—	—	(1,011.6)	—	(1,011.6)
Reclassification related to ASU 2018-02 adoption	—	—	—	—	—	3.8	(3.8)	—
Common stock repurchased and retired	(6.2)	(0.1)	—	—	—	(58.3)	—	(58.4)
Share-based compensation	3.0	0.1	(1.1)	(11.4)	33.7	—	—	22.4
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	0.6	0.6
Balance at December 31, 2018	239.8	2.4	(3.1)	(45.6)	1,431.9	1,376.5	(14.3)	2,750.9
Net income (loss)	—	—	—	—	—	(97.3)	—	(97.3)
Cash dividends declared, $0.04 per share	—	—	—	—	—	(9.6)	—	(9.6)
Share-based compensation	2.3	—	(1.3)	(9.8)	24.6	—	—	14.8
Change in pension and postretirement liability, net of tax	—	—	—	—	—	—	1.8	1.8
Balance at December 31, 2019	242.1	2.4	(4.4)	(55.4)	1,456.5	1,269.6	(12.5)	2,660.6
Net income (loss)	**—**	**—**	**—**	**—**	**—**	**3.2**	**—**	**3.2**
Cash dividends declared, $0.02 per share	**—**	**—**	**—**	**—**	**—**	**(4.8)**	**—**	**(4.8)**
Share-based compensation	**5.9**	**0.1**	**(1.0)**	**(2.2)**	**13.6**	**—**	**—**	**11.5**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(0.3)**	**(0.3)**
Balance at December 31, 2020	**248.0**	**$ 2.5**	**(5.4)**	**$ (57.6)**	**$ 1,470.1**	**$ 1,268.0**	**$ (12.8)**	**$ 2,670.2**

Refer to Notes accompanying the Consolidated Financial Statements.

QEP RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2020	2019	2018
OPERATING ACTIVITIES	(in millions)		
Net income (loss)	**$ 3.2**	$ (97.3)	$ (1,011.6)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Depreciation, depletion and amortization	**574.0**	540.0	857.1
Deferred income taxes (benefit)	**110.6**	4.3	(247.6)
Impairment	**8.7**	5.0	1,560.9
Non-cash share-based compensation	**12.4**	20.8	30.9
Amortization of debt issuance costs and discounts	**4.7**	5.4	5.4
Net (gain) loss from asset sales, inclusive of restructuring costs	**(1.2)**	(3.9)	(25.0)
(Gain) loss from early extinguishment of debt	**(18.2)**	1.0	—
Unrealized (gains) losses on marketable securities	**(3.2)**	(3.9)	1.2
Unrealized (gains) losses on derivative contracts	**59.2**	138.3	(248.5)
Changes in operating assets and liabilities			
Accounts receivable	**19.2**	(4.1)	33.7
Prepaid expenses	**(2.9)**	(0.4)	(2.0)
Accounts payable and accrued expenses	**(42.4)**	(40.4)	(74.2)
Income taxes receivable	**4.2**	38.4	(71.0)
Other	**(55.1)**	(36.3)	6.9
Net Cash Provided by (Used in) Operating Activities	**673.2**	566.9	816.2
INVESTING ACTIVITIES			
Property acquisitions	**(4.1)**	(3.5)	(65.6)
Expenditures for property, plant and equipment	**(353.5)**	(562.7)	(1,234.1)
Proceeds from disposition of assets	**13.8**	678.9	243.6
Net Cash Provided by (Used in) Investing Activities	**(343.8)**	112.7	(1,056.1)
FINANCING ACTIVITIES			
Checks outstanding in excess of cash balances	**(16.1)**	3.7	(29.5)
Long-term debt issuance costs paid	**(0.6)**	—	(0.1)
Long-term debt extinguishment costs paid	**—**	(1.0)	—
Repurchases and redemptions of senior notes	**(410.3)**	(66.9)	—
Proceeds from credit facility	**37.0**	56.1	3,608.0
Repayments of credit facility	**(37.0)**	(486.0)	(3,267.0)
Common stock repurchased and retired	**—**	—	(58.4)
Treasury stock repurchases	**(1.7)**	(7.6)	(8.7)
Dividends paid	**(4.8)**	(9.6)	—
Other capital contributions	**—**	—	0.3
Net Cash Provided by (Used in) Financing Activities	**(433.5)**	(511.3)	244.6
Change in cash, cash equivalents and restricted cash[1]	**(104.1)**	168.3	4.7
Beginning cash, cash equivalents and restricted cash[1]	**196.4**	28.1	23.4
Ending cash, cash equivalents and restricted cash[1]	**$ 92.3**	**$ 196.4**	**$ 28.1**

(1) Refer to Recent Accounting Developments in Note 1 – Summary of Significant Accounting Policies.

Refer to Notes accompanying the Consolidated Financial Statements.

Note 1 – Summary of Significant Accounting Policies

Nature of Business

QEP Resources, Inc. (QEP or the Company) is an independent crude oil and natural gas exploration and production company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota). Unless otherwise specified or the context otherwise requires, all references to "QEP" or the "Company" are to QEP Resources, Inc. and its subsidiaries on a consolidated basis. QEP's corporate headquarters are located in Denver, Colorado and shares of QEP's common stock trade on the New York Stock Exchange (NYSE) under the ticker symbol "QEP".

Principles of Consolidation

The Consolidated Financial Statements (financial statements) contain the accounts of QEP and its majority-owned or controlled subsidiaries. The financial statements were prepared in accordance with GAAP and with the instructions for annual reports on Form 10-K and Regulation S-X. All intercompany accounts and transactions have been eliminated in consolidation.

All dollar and share amounts in these financial statements are in millions, except per share information and where otherwise noted.

Merger

On December 20, 2020, the Company entered into an Agreement and Plan of Merger (Merger Agreement) with Diamondback Energy, Inc. (Diamondback) and Bohemia Merger Sub, Inc., a wholly owned subsidiary of Diamondback (Merger Sub), which provides that, among other things, and subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into QEP, with QEP surviving as a direct, wholly owned subsidiary of Diamondback (Merger). Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of the Company (other than any Excluded Shares, any Converted Shares and Company Restricted Stock Awards (each as defined in the Merger Agreement)) will be converted into the right to receive 0.05 shares, par value $0.01 per share, of common stock of Diamondback (Merger Consideration). The Merger Agreement provides that, among other things, during the period from the date of the Merger Agreement until the effective time of the Merger, the Company and its subsidiaries are not permitted to declare, set aside or pay any dividends on any shares of capital stock of the Company or its subsidiaries. The Merger Agreement also addresses the treatment of QEP equity awards in the Merger. Diamondback's common stock is listed and traded on the NASDAQ Global Select Market under the symbol "FANG". The transaction was unanimously approved by the Boards of Directors of both companies. The Merger is expected to close late in the first quarter of 2021, and is subject to the approval of the Company's stockholders and other customary closing conditions. During the year ended December 31, 2020, the Company incurred $4.5 million of merger costs recognized in "General and administrative" expense on the Consolidated Statements of Operations (statements of operations) and $5.0 million of additional merger costs recognized in "Prepaid expenses" on the Consolidated Balance Sheets (balance sheets) as of December 31, 2020.

Business Segments

QEP conducted a segment analysis in accordance with Accounting Standards Codification (ASC) Topic 280, *Segment Reporting*, and determined that the Company's two operating segments (Permian Basin and Williston Basin) should be aggregated into one reportable segment.

Use of Estimates

The preparation of the financial statements and Notes in conformity with GAAP requires that management formulate estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities. A significant item that requires management's estimates and assumptions is the estimate of proved oil and condensate, gas and NGL reserves, which are used in the calculation of depreciation, depletion and amortization rates of its oil and gas properties, impairment of proved properties and asset retirement obligations. Changes in estimated quantities of its reserves could impact the Company's reported financial results as well as disclosures regarding the quantities and value of proved oil and gas reserves. Other items subject to significant estimates and assumptions include income taxes and impairment. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Risks and Uncertainties

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil, gas and NGL, which are affected by many factors outside of QEP's control, including changes in market supply and demand. The novel coronavirus disease (COVID-19) pandemic and related shut-down of various sectors of the global economy resulted in a significant reduction in global demand for crude oil in 2020. Changes in market supply and demand are also impacted by Organization of Petroleum Exporting Countries (OPEC) production levels, weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. Field-level prices received for QEP's oil and gas production have historically been volatile and may be subject to significant fluctuations in the future. The Company's derivative contracts serve to mitigate in part the effect of this price volatility on the Company's cash flows, and the Company has derivative contracts in place for a portion of its expected future oil and condensate production. Refer to Note 6 – Derivative Contracts for the Company's open oil commodity derivative contracts.

Revenue Recognition

QEP recognizes revenue from the sale of oil and condensate, gas and NGL in the period that the performance obligations are satisfied. QEP's performance obligations are satisfied when the customer obtains control of product, when QEP has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable. The sale of oil and condensate, gas and NGL are made under contracts with customers, which typically include consideration that is based on pricing tied to local indices and volumes delivered in the current month. Reported revenues include estimates for the two most recent months using published commodity price indices and volumes supplied by field operators. Performance obligations under our contracts with customers are typically satisfied at a point in time through monthly delivery of oil and condensate, gas and/or NGL. Our contracts with customers typically require payment for oil and condensate, gas and NGL sales within 30 days following the calendar month of delivery.

QEP's oil and condensate is typically sold at specific delivery points under contract terms that are common in the industry. QEP's gas and NGL are also sold under contract types that are common in the industry; however, under these contracts, the gas and its components, including NGL, may be sold to a single purchaser or the residue gas and NGL may be sold to separate purchasers. Regardless of the contract type, the terms of these contracts compensate QEP for the value of the residue gas and NGL constituent components at market prices for each product. QEP also purchases and resells oil and gas primarily to fulfill volume commitments when production does not fulfill contractual commitments and to capture additional margin from subsequent sales of third party purchases. QEP recognizes revenue from these resale activities in the period that the performance obligations are satisfied.

For product sales that have a contract term greater than one year, the Company follows ASC 606-10-50-14(a), which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each monthly product delivery generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist principally of highly liquid investments in securities with original maturities of three months or less made through commercial bank accounts that result in available funds the next business day. Restricted cash are funds that are legally or contractually reserved for a specific purpose and therefore not available for immediate or general business use.

The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the balance sheets to the amounts shown in the statements of cash flows:

	December 31,	
	2020	2019
	(in millions)	
Cash and cash equivalents	**$ 60.4**	$ 166.3
Restricted cash[1]	**31.9**	30.1
Total cash, cash equivalents and restricted cash shown in the Consolidated Statements of Cash Flows	**$ 92.3**	$ 196.4

(1) As of December 31, 2020 and 2019, the restricted cash balance primarily related to cash deposited into an escrow account for a title dispute between outside parties in the Williston Basin, and the restricted cash balance is recorded within "Other noncurrent assets" on the balance sheets.

Supplemental cash flow information is shown in the table below:

	Year Ended December 31,		
	2020	2019	2018
Supplemental Disclosures:	(in millions)		
Cash paid for interest, net of capitalized interest	**$ 118.4**	$ 126.9	$ 136.9
Cash paid (refund received) for income taxes, net	**$ (164.0)**	$ (66.7)	$ 0.8
Cash paid for amounts included in the measurement of lease liabilities	**$ 25.7**	$ 25.3	$ —
Other Non-cash Activities:			
Right-of-use assets obtained in exchange for operating lease obligations	**$ 11.0**	$ 16.6	$ —
Non-cash Investing Activities:			
Capital expenditure accruals as of December 31,	**$ 37.8**	$ 63.3	$ 54.5

Accounts Receivable

Accounts receivable consists mainly of receivables from oil and gas purchasers and joint interest owners on properties the Company operates. The sale of oil, gas and NGLs exposes the Company to credit losses. The Company's expected loss allowance methodology for accounts receivable is developed using historical collection experience, current and future economic and market conditions and a review of the current status of customers' trade accounts receivables. For receivables from joint interest owners, the Company has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's oil and gas receivables are collected and credit losses are minimal. However, if commodity prices remain low for an extended period of time, the Company could incur increased levels of bad debt expense. Bad debt recovery associated with accounts receivable for the year ended December 31, 2020 was $0.3 million, and bad debt expense for the years ended December 31, 2019 and 2018 was $0.3 million, and $0.6 million, respectively. Bad debt expense or recovery is included in "General and administrative" expense on the Consolidated Statements of Operations (statements of operations). The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectability. As of December 31, 2020 and 2019, the allowance for cumulative expected credit losses was $1.7 million and $1.6 million, respectively.

Property, Plant and Equipment

Property, plant and equipment balances are stated at historical cost. Significant accounting policies for our property, plant and equipment are as follows:

Successful Efforts Accounting for Oil and Gas Operations
The Company follows the successful efforts method of accounting for oil and gas property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, delay rentals and administrative costs associated with unproved property and unsuccessful exploratory well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production depreciation, depletion and amortization rate would be significantly affected. Capitalized costs of unproved properties are reclassified to proved property when related proved reserves are determined or charged against accumulated impairment when abandoned.

Depreciation, Depletion and Amortization (DD&A)
Capitalized proved leasehold costs are depleted on a field-by-field basis using the unit-of-production method and the estimated total proved oil and gas reserves. Capitalized costs of exploratory wells that have found proved oil and gas reserves and capitalized development costs are depreciated using the unit-of-production method based on estimated proved developed reserves for a successful effort field. The Company capitalizes an estimate of the fair value of future abandonment costs upon initial recognition.

DD&A for the Company's remaining property, plant and equipment is generally based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets using the straight-line method. The estimated useful lives of those assets depreciated under the straight-line basis generally range as follows:

Buildings	10 to 30 years
Leasehold improvements	3 to 10 years
Service, transportation and field service equipment	3 to 7 years
Furniture and office equipment	3 to 7 years

Impairment of Long-Lived Assets
Proved oil and gas properties are evaluated on a field-by-field basis for impairment. Other property, plant, and equipment are evaluated on a specific asset basis or in groups of similar assets, as applicable. When an indicator of impairment, or a "triggering event," is identified, the Company uses a cash flow model to assess its proved properties and operating lease right-of-use assets for impairment. Triggering events could include, but are not limited to, a reduction of oil and condensate, gas and NGL reserves caused by mechanical problems, faster-than-expected decline of production, lease ownership issues, potential disposition of assets, merger transactions and declines in oil, gas and NGL prices. When a triggering event is identified, the undiscounted future net cash flows of an evaluated asset are compared to the asset's carrying value. Cash flow estimates require forecasts and significant estimates and assumptions for many years into the future for a variety of factors, including estimates of future production, future oil and gas prices, future operating costs, future development costs and our five-year development plan. Cash flow estimates relating to future cash flows from probable and possible reserves are reduced by additional risk-weighting factors. If the asset's carrying value exceeds the related undiscounted net cash flows, fair value of the evaluated asset is estimated using a discounted cash flow approach. The signing of a merger or purchase and sale agreement could also cause the Company to evaluate for, or recognize, an impairment of proved properties. For assets subject to a merger or purchase and sale agreement, the evaluation of terms of the merger or purchase and sale agreement are used as an indicator of fair value. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach in which the likelihood of possible outcomes is taken into consideration.

As of March 31, 2020, December 31, 2020 and December 31, 2019, the Company performed an assessment of recoverability and determined that the carrying value of proved properties was less than the respective undiscounted future cash flows, and therefore recorded no impairment. In the evaluation of recoverability as of December 31, 2020, the Company considered the estimated future pricing used by management in evaluating and entering into the Merger Agreement.

Unproved properties are evaluated on a specific asset basis or in groups of similar assets, as applicable. The Company performs periodic assessments of unproved oil and gas properties for impairment and recognizes a loss at the time of impairment. In determining whether an unproved property is impaired, the Company considers numerous factors including, but not limited to, current development and exploration drilling plans, favorable or unfavorable exploration activity on adjacent leaseholds, in-house geologists' evaluation of the lease, future reserve cash flows and the remaining lease term.

During the year ended December 31, 2020, QEP recorded unproved property impairment charges of $8.7 million related to anticipated leasehold expirations.

During the year ended December 31, 2019, QEP recorded impairment charges of $5.0 million related to an office building lease.

During the year ended December 31, 2018, QEP recorded impairment charges of $1,560.9 million, of which $1,559.3 million related to proved and unproved properties impairment as a result of signing purchase and sale agreements for the divestitures of the Williston Basin and Uinta Basin assets. The Williston Basin assets were impaired in the fourth quarter utilizing a probability-weighted assets held and use model, and the Uinta Basin assets were impaired in the second quarter utilizing an assets held for sale model.

Asset Retirement Obligations (ARO)
QEP is obligated to fund the costs of disposing of long-lived assets upon their abandonment. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. ARO associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement costs, is depreciated over the useful life of the asset. The ARO liability is recorded at estimated fair value upon initial recognition, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. If estimated future costs of ARO change, an adjustment is recorded to both the ARO liability and the long-lived asset. Revisions to estimated ARO can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. Refer to Note 4 – Asset Retirement Obligations for more information.

Litigation and Other Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its financial statements. The amount of ultimate loss may differ from these estimates. In accordance with ASC 450, *Contingencies*, an accrual is recorded for a loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes. Refer to Note 10 – Commitments and Contingencies for more information.

QEP accrues losses associated with environmental obligations when such losses are probable and can be reasonably estimated. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as more information becomes available or as circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable.

Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. QEP uses commodity derivative instruments, typically fixed-price swaps, basis swaps, costless collars and calendar month average (CMA) rolls to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative instruments do not require the physical delivery of oil or gas between the parties at settlement. All transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. QEP does not engage in speculative hedging transactions, nor does it buy and sell energy contracts with the objective of generating profits on short-term differences in price. Additionally, QEP does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates.

These derivative contracts are recorded in "Realized and unrealized gains (losses) on derivative contracts" on the statements of operations in the month of settlement and are also marked-to-market monthly. Refer to Note 6 – Derivative Contracts for more information.

Credit Risk

Management believes that its credit review procedures, loss reserves, cash deposits and investments, and collection procedures have adequately provided for usual and customary credit-related losses. Exposure to credit risk may be affected by extended periods of low commodity prices, as well as the concentration of customers in certain regions due to changes in economic or other conditions. Customers include commercial and industrial enterprises and financial institutions that may react differently to changing conditions.

The Company utilizes various processes to monitor and evaluate its credit risk exposure, which include closely monitoring current market conditions and counterparty credit fundamentals, including public credit ratings, where available. Credit exposure is controlled through credit approvals and limits based on counterparty credit fundamentals. Credit exposure is aggregated across all lines of business, including derivatives, physical exposure and short-term cash investments. To further manage the level of credit risk, the Company requests credit support and, in some cases, requests parental guarantees, letters of credit or prepayment from companies with perceived higher credit risk. Reserves for expected credit losses are periodically reviewed for adequacy. The Company also has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

The Company enters into International Swap Dealers Association Master Agreements (ISDA Agreements) with each of its derivative counterparties prior to executing derivative contracts. The terms of the ISDA Agreements provide, among other things, the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or counterparty to a derivative contract. The Company routinely monitors and manages its exposure to counterparty risk related to derivative contracts by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties public credit ratings, and avoiding concentration of credit exposure by transacting with multiple counterparties. The Company's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings.

The Company's five largest customers accounted for 63%, 66%, and 49% of QEP's revenues for the years ended December 31, 2020, 2019 and 2018, respectively. The following table presents the percentages by customer that accounted for 10% or more of QEP's total revenues.

Year Ended December 31, 2020	
Valero Marketing & Supply Company	**30 %**
Phillips 66 Company	**12 %**
Year Ended December 31, 2019	
Occidental Energy Marketing	21 %
Valero Marketing & Supply Company	18 %
Plains Marketing LP	17 %
Year Ended December 31, 2018	
Occidental Energy Marketing	16 %
Plains Marketing LP	12 %

Income Taxes

The amount of income taxes recorded by QEP requires interpretations of complex rules and regulations of various tax jurisdictions throughout the United States. QEP has recognized deferred tax assets and liabilities for temporary differences, operating losses and tax credit carryforwards. Deferred income taxes are provided for the temporary differences arising between the book and tax carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods.

ASC 740, *Income Taxes*, specifies the accounting for uncertainty in income taxes by prescribing a minimum recognition threshold for a tax position to be reflected in the financial statements. If recognized, the tax benefit is measured as the largest amount of tax benefit that is more-likely-than-not to be realized upon ultimate settlement. Management has considered the amounts and the probabilities of the outcomes that could be realized upon ultimate settlement and believes that it is more-likely-than-not that the Company's recorded income tax benefits will be fully realized, or recognizes a valuation allowance against deferred tax assets in cases where we do not forecast sufficient future income to recognize the deferred tax asset. All federal income tax returns prior to 2019 have been examined by the Internal Revenue Service and are closed or have been pre-reviewed before filing. The federal income tax return for 2019 remains subject to examination and the 2020 return has not yet been filed. Most state tax returns for 2017 and subsequent years remain subject to examination. Should the Company utilize any of its state loss carryforwards, their carryforward losses would be subject to examination.

The benefits of uncertain tax positions taken or expected to be taken on income tax returns is recognized in the consolidated financial statements at the largest amount that is more-likely-than-not to be sustained upon examination by the relevant taxing authorities.

Tax legislation enacted in December 2017 (Tax Cuts and Jobs Act) changed several aspects of corporate taxation, including reducing our federal corporate statutory tax from 35% to 21%, limiting the amount of interest the Company could potentially deduct and eliminating the corporate Alternative Minimum Tax (AMT). The elimination of the corporate AMT allowed the Company to claim refunds for AMT credits carried forward from prior tax years. The Coronavirus Aid, Relief, and Economic Security Act (CARES Act) enacted in March 2020 permitted the Company to carry back its net operating loss (NOL) generated in 2018 and 2019, creating additional AMT credits, and to accelerate all of its AMT refunds. Guidance issued by the relevant regulatory authorities regarding tax legislation may materially impact QEP's financial statements. As additional guidance to the Tax Cuts and Jobs Act and the CARES Act is published in the form of Treasury Regulations and other IRS communications, the Company will monitor, assess and determine the impact of these communications on the Company's consolidated financial statements and statements of operations.

Treasury Stock

We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as a reduction in shareholders' equity in the balance sheets. QEP acquires treasury stock from stock forfeitures and withholdings and uses the acquired treasury stock for stock option exercises and certain stock grants to employees. Refer to Note 11 – Share-Based and Long-Term Compensation for more information.

Earnings (Loss) Per Share

Basic earnings (loss) per share (EPS) are computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the reporting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options.

The Company's unvested restricted share awards, once granted, are considered issued and outstanding, the historical forfeiture rate is minimal, are eligible to receive dividends, and do not have a contractual obligation to share in losses of the Company. Accordingly, restricted share awards are considered participating securities. The Company's unexercised stock options do not contain rights to dividends. Under the two-class method, the earnings used to determine basic earnings (loss) per common share are reduced by an amount allocated to participating securities. When the Company records a net loss, none of the loss is allocated to the participating securities since the securities are not obligated to share in Company losses. Use of the two-class method has an insignificant impact on the calculation of basic and diluted earnings (loss) per common share. For the year ended December 31, 2020, there were no anti-dilutive shares. For the years ended December 31, 2019 and 2018, the Company was in a loss position, therefore, all potentially dilutive securities were anti-dilutive.

The following is a reconciliation of the components of basic and diluted shares used in the EPS calculation:

	December 31,		
	2020	2019	2018
	(in millions)		
Weighted-average basic common shares outstanding	**241.6**	237.7	237.9
Potential number of shares issuable upon exercise of in-the-money stock options under the Long-Term Stock Incentive Plan	**—**	—	—
Average diluted common shares outstanding	**241.6**	237.7	237.9

Share-Based and Long-Term Compensation

QEP issues restricted share awards, restricted cash awards and restricted share units to certain officers, employees and non-employee directors under its 2018 LTIP. QEP historically issued stock options. QEP used the Black-Scholes-Merton mathematical model to estimate the fair value of stock options for accounting purposes. The grant date fair value for restricted share awards is determined based on the closing bid price of the Company's common stock on the grant date. Share-based compensation cost for restricted share units is equal to its fair value as of the end of the period and is classified as a liability. QEP uses an accelerated method in recognizing share-based compensation costs for stock options and restricted share awards with graded-vesting periods. Stock options held by employees generally vest in three equal, annual installments and primarily have a term of seven years. Restricted share awards and restricted share units vest in equal installments over a specified number of years after the grant date with the majority vesting in three years. Non-vested restricted share awards have voting and dividend rights; however, sale or transfer is restricted. Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over a three-year period and are deferred into the Company's nonqualified, unfunded deferred compensation plan at the time of grant. Restricted cash award grants vest in equal installments over three years from the grant date. Share-based compensation cost for restricted cash awards is equal to its fair value as of the end of the period and is classified as a liability. The Company also issues performance share unit awards under its Cash Incentive Plan that are generally paid out in cash depending upon the Company's total shareholder return compared to a group of its peers over a three-year period. Share-based compensation cost for the performance share units is equal to its fair value as of the end of the period and is classified as a liability. Refer to Note 11 – Share-Based and Long-Term Compensation for more information.

Pension and Other Postretirement Benefits

QEP maintains closed, defined-benefit pension and other postretirement benefit plans, including both a qualified and a supplemental plan. QEP also provides certain health care and life insurance benefits for certain retired QEP employees. Determination of the benefit obligations for QEP's defined-benefit pension and other postretirement benefit plans impacts the recorded amounts for such obligations on the balance sheets and the amount of benefit expense recorded to the statements of operations.

QEP measures pension plan assets at fair value. Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement benefit plans include the discount rate, the expected rate of return on plan assets (for funded pension plans) and the rate of future compensation increases. Other assumptions involve demographic factors such as retirement, mortality and turnover. QEP evaluates and updates its actuarial assumptions at least annually. QEP recognizes a pension curtailment immediately when there is a significant reduction in, or an elimination of, defined-benefit accruals for present employees' future services. Refer to Note 12 – Employee Benefits for more information.

Comprehensive Income (Loss)

Comprehensive income (loss) is the sum of net income (loss) as reported in the statements of operations and changes in the components of other comprehensive income (loss). Other comprehensive income (loss) includes certain items that are recorded directly to equity and classified as accumulated other comprehensive income (AOCI), which includes changes in the underfunded portion of the Company's defined-benefit pension and other postretirement benefits plans and changes in deferred income taxes on such amounts. These transactions do not represent the culmination of the earnings process but result from periodically adjusting historical balances to fair value.

Recent Accounting Developments

In June 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-13, *Financial Instruments - Credit Losses (Topic 326) - Measurement of credit losses on financial instruments,* which requires a company to consider forward-looking information to determine current estimated credit losses (CECL), for all financial instruments that are not accounted for at fair value through net income. Previously, credit losses on financial assets were only required to be recognized when they were incurred. The Company adopted ASU 2016-13 on January 1, 2020. The guidance did not have a significant impact on the financial statements or notes accompanying the financial statements.

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement (Topic 820) - Disclosure framework - Changes to the disclosure requirements for fair value measurement,* which modifies the disclosure requirements on fair value measurements in Topic 820. The Company adopted ASU 2018-13 on January 1, 2020. The guidance did not have a significant impact on the financial statements or notes accompanying the financial statements.

In March 2020, the FASB issued ASU No. 2020-04, *Reference Rate Reform*, which provides temporary optional guidance to companies impacted by the transition away from the London Interbank Offered Rate (LIBOR). The amendment provides certain expedients and exceptions to applying GAAP in order to lessen the burden when contracts, hedging relationships and other transactions that reference LIBOR as a benchmark are modified. This amendment is effective upon issuance and expires on December 31, 2022. The Company is currently assessing the impact of the LIBOR transition and this ASU on the Company's financial statements.

In October 2020, the FASB issued ASU No. 2020-10, *Codification Improvements*, which amends and clarifies various Topics within the Codification in order to improve clarity and consistency. The amendment will be effective for periods beginning after December 15, 2020, and early adoption is permitted. The Company is currently assessing the impact of this ASU on the Company's financial statements.

Note 2 – Revenue

Revenue Recognition

QEP recognizes revenue in accordance with ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)*. Refer to Note 1 – Summary of Significant Accounting Policies for more information regarding revenue recognition.

The following tables present QEP's revenues that are disaggregated by revenue source and by geographic area.

	Oil and condensate sales	Gas sales	NGL sales	Transportation and processing costs included in revenue	Oil and condensate, gas and NGL sales
	(in millions)				
	Year Ended December 31, 2020				
Northern Region					
Williston Basin	**$ 249.9**	**$ 18.1**	**$ 14.4**	**$ (37.8)**	**$ 244.6**
Other Northern	**0.2**	**1.1**	**—**	**—**	**1.3**
Southern Region					
Permian Basin	**441.7**	**20.4**	**31.3**	**(24.7)**	**468.7**
Other Southern	**—**	**—**	**—**	**—**	**—**
Total oil and condensate, gas and NGL sales	**$ 691.8**	**$ 39.6**	**$ 45.7**	**$ (62.5)**	**$ 714.6**
	Year Ended December 31, 2019				
Northern Region					
Williston Basin	$ 420.8	$ 33.1	$ 19.4	$ (34.4)	$ 438.9
Other Northern	1.1	0.4	0.1	—	1.6
Southern Region					
Permian Basin	710.6	12.8	37.8	(20.5)	740.7
Other Southern[(1)]	0.1	6.1	—	—	6.2
Total oil and condensate, gas and NGL sales	$ 1,132.6	$ 52.4	$ 57.3	$ (54.9)	$ 1,187.4
	Year Ended December 31, 2018				
Northern Region					
Williston Basin	$ 707.0	$ 45.3	$ 56.5	$ (43.1)	$ 765.7
Uinta Basin	25.3	25.0	4.8	—	55.1
Other Northern	4.9	2.0	—	—	6.9
Southern Region					
Permian Basin	684.4	17.3	49.5	(11.9)	739.3
Haynesville/Cotton Valley	1.0	303.1	—	—	304.1
Other Southern	(0.2)	0.4	—	—	0.2
Total oil and condensate, gas and NGL sales	$ 1,422.4	$ 393.1	$ 110.8	$ (55.0)	$ 1,871.3

(1) For the year ended December 31, 2019, $5.9 million of revenues associated with Haynesville/Cotton Valley have been included in Other Southern.

Note 3 – Acquisitions and Divestitures

Acquisitions

During the years ended December 31, 2020, 2019 and 2018, QEP acquired various oil and gas properties, which primarily included proved leasehold acreage in the Permian Basin for an aggregate purchase price of $4.1 million, $3.5 million and $65.6 million, respectively, subject to post-closing purchase price adjustments.

Divestitures

In February 2018, QEP's Board of Directors (Board) unanimously approved certain strategic and financial initiatives including plans to market its assets in the Williston Basin, Uinta Basin and Haynesville/Cotton Valley and focus its activities in the Permian Basin. The Company subsequently sold its Uinta Basin assets in September 2018 and sold its Haynesville/Cotton Valley assets in January 2019. In addition, the Company entered into a purchase and sale agreement for its Williston Basin assets in November 2018. However, in February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement (Terminated Williston Basin Divestiture).

Haynesville/Cotton Valley Divestiture

In November 2018, the Company's wholly owned subsidiaries, QEP Energy Company, QEP Marketing Company, and QEP Oil & Gas Company, entered into a definitive agreement to sell their assets in Haynesville/Cotton Valley for a purchase price of $735.0 million, subject to purchase price adjustments, including adjustments for certain title and environmental defects asserted prior to the closing (Haynesville Divestiture). In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, to be resolved pursuant to the purchase and sale agreement's title dispute resolution procedures. In January 2019, QEP closed the Haynesville Divestiture and during the year ended December 31, 2019 reached final settlement on asserted title defects and received net cash proceeds of $633.9 million. During the years ended December 31, 2019 and 2018, QEP recorded a pre-tax loss, including restructuring costs, of $1.0 million and $3.0 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statements of operations.

During the year ended December 31, 2019, QEP accounted for revenues and expenses related to Haynesville/Cotton Valley, including the pre-tax loss on sale of $1.0 million as income from continuing operations on the statements of operations because the Haynesville Divestiture did not cause a strategic shift for the Company and therefore did not qualify as discontinued operations under ASU 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. During the year ended December 31, 2019, QEP recorded net income before income taxes related to the divested Haynesville/Cotton Valley assets, prior to divestiture, of $3.2 million which includes the pre-tax loss on sale of $1.0 million. During the year ended December 31, 2018, QEP recorded net income before income taxes related to the divested Haynesville/Cotton Valley assets of $76.0 million. In addition, QEP recorded $1.4 million and $3.0 million of restructuring costs related to this divestiture during the years ended December 31, 2019 and 2018, respectively, included in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statements of operations. Refer to Note 8 – Restructuring for more information.

Terminated Williston Basin Divestiture

In November 2018, the Company's wholly owned subsidiary, QEP Energy Company, entered into a purchase and sale agreement for its assets in the Williston Basin for a purchase price of $1,725.0 million, subject to purchase price adjustments. The purchase price was comprised of $1,650.0 million in cash and contractual rights to receive $75.0 million of the buyer's common stock if certain conditions were met. The transaction was subject to certain conditions, including, but not limited to, approval of buyer's shareholders and regulatory approvals. As a result of signing the purchase and sale agreement, the Company recorded impairments of proved and unproved properties of $1,560.9 million. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement (Terminated Williston Basin Divestiture). As a part of our strategic initiatives, QEP has incurred costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 8 – Restructuring for more information.

Uinta Basin Divestiture

In September 2018, QEP sold its natural gas and oil producing properties, undeveloped acreage and related assets located in the Uinta Basin for net cash proceeds of $153.0 million, (Uinta Basin Divestiture). During the year ended December 31, 2018, QEP recorded a pre-tax loss of $12.6 million related to the Uinta Basin Divestiture, which included $5.4 million related to estimated restructuring costs recorded on the statements of operations within "Net gain (loss) from asset sales, inclusive of restructuring costs". In conjunction with the Uinta Basin Divestiture, QEP recorded $402.8 million of proved and unproved properties impairment during the year ended December 31, 2018. For the year ended December 31, 2019, QEP recorded a pre-tax loss of $0.2 million, due to post-closing purchase price adjustments, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs". Refer to Note 1 – Summary of Significant Accounting Policies and Note 8 – Restructuring for more information.

Other Divestitures

During the year ended December 31, 2020, QEP received net cash proceeds of $13.8 million and recorded a net pre-tax gain on sale of $1.2 million primarily related to the divestiture of properties outside our main operating areas.

In addition to the Haynesville and Uinta Basin divestitures, during the year ended December 31, 2019, QEP received net cash proceeds of $45.1 million and recorded a net pre-tax gain on sale of $5.1 million related to the divestiture of properties outside our main operating areas.

In addition to the Uinta Basin Divestiture, during the year ended December 31, 2018, QEP received net cash proceeds of $90.6 million and recorded a pre-tax gain on sale of $38.5 million, primarily related to the divestiture of properties outside our main operating areas.

These gains and losses are reported on the statements of operations within "Net gain (loss) from asset sales, inclusive of restructuring costs".

Note 4 – Asset Retirement Obligations

QEP records ARO associated with the retirement of tangible, long-lived assets. The Company's ARO liability applies primarily to abandonment costs associated with oil and gas wells and certain other properties. The fair values of such costs are estimated by Company personnel based on abandonment costs of similar assets and depreciated over the life of the related assets. Revisions to the ARO estimates result from changes in expected cash flows or material changes in estimated asset retirement costs. The ARO liability is adjusted each period through an accretion calculation using a credit-adjusted risk-free interest rate.

The Consolidated Balance Sheet line items of QEP's ARO liability are presented in the table below:

	Asset Retirement Obligations	
	December 31,	
	2020	2019
Balance Sheet line item	(in millions)	
Current:		
Asset retirement obligations, current liability	**$ 6.4**	$ 6.0
Long-term:		
Asset retirement obligations	**96.3**	94.9
Total ARO Liability	**$ 102.7**	$ 100.9

The following is a reconciliation of the changes in the Company's ARO for the periods specified below:

	Asset Retirement Obligations	
	2020	2019
	(in millions)	
ARO liability at January 1,	**$ 100.9**	$ 159.6
Accretion	**4.0**	5.2
Additions	**1.2**	1.1
Revisions	**—**	(2.2)
Liabilities related to assets sold[(1)]	**(1.4)**	(60.7)
Liabilities settled	**(2.0)**	(2.1)
ARO liability at December 31,	**$ 102.7**	$ 100.9

(1) Liabilities related to assets sold for the year ended December 31, 2019, includes $57.6 million related to the Haynesville Divestiture. Refer to Note 3 – Acquisitions and Divestitures for more information.

Note 5 – Fair Value Measurements

QEP measures and discloses fair values in accordance with the provisions of ASC 820, *Fair Value Measurements and Disclosures*. This guidance defines fair value in applying GAAP, establishes a framework for measuring fair value and expands disclosures about fair value measurements. ASC 820 also establishes a fair value hierarchy. Level 1 inputs are quoted prices (unadjusted) for identical assets or liabilities in active markets that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability.

QEP maximizes its use of observable inputs and minimizes its use of unobservable inputs. In addition to using market data, QEP makes assumptions in valuing its assets and liabilities, including assumptions about risk and the risks inherent in the inputs to the valuation technique. The Company's policy is to recognize significant transfers between levels at the end of the reporting period.

QEP has determined that its commodity derivative instruments are Level 2. The Level 2 fair value of commodity derivative contracts (refer to Note 6 – Derivative Contracts for more information) is based on market prices posted for the respective commodity on the last trading day of the reporting period and industry standard discounted cash flow models. Certain of the Company's commodity derivative instruments are valued using industry standard models that consider various inputs, including quoted forward prices for commodities, time value, volatility, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable prices at which transactions are executed in the marketplace. The determination of fair value for derivative assets and liabilities also incorporates nonperformance risk for counterparties and for QEP. Derivative contract fair values are reported on a net basis to the extent a legal right of offset with the counterparty exists.

QEP offers a nonqualified, unfunded deferred compensation wrap plan (Wrap Plan) to certain individuals. The Company established a trust (Rabbi Trust) to hold the investments associated with the Wrap Plan (other than phantom QEP shares) and to pay Wrap Plan obligations as they arise. QEP has determined that the marketable securities held by the Rabbi Trust and the Wrap Plan obligations are Level 1. The fair value of the marketable securities in the Rabbi Trust is based on actively traded mutual funds. The Wrap Plan obligations, which represent the underlying liabilities to the participants in the Wrap Plan, are recorded at amounts due to participants, based on the fair value of the participants' selected investments, including both actively traded funds and phantom QEP shares. Refer to Note 12 – Employee Benefits for additional information.

The fair value of financial assets and liabilities at December 31, 2020 and 2019, is shown in the table below:

	Level 1	Level 2	Level 3	Netting Adjustments[1]	Net Amounts Presented on the Consolidated Balance Sheets
	Fair Value Measurements				
	Gross Amounts of Assets and Liabilities				
	(in millions)				
	December 31, 2020				
Financial Assets					
Fair value of derivative contracts – short-term	**$ —**	**$ 1.4**	**$ —**	**$ (1.4)**	**$ —**
Fair value of derivative contracts – long-term	**—**	**—**	**—**	**—**	**—**
Fair value of Rabbi Trust marketable securities	**23.4**	**—**	**—**	**—**	**23.4**
Total financial assets	**$ 23.4**	**$ 1.4**	**$ —**	**$ (1.4)**	**$ 23.4**
Financial Liabilities					
Fair value of derivative contracts – short-term	**$ —**	**$ 77.8**	**$ —**	**$ (1.4)**	**$ 76.4**
Fair value of derivative contracts – long-term	**—**	**0.3**	**—**	**—**	**0.3**
Fair value of Wrap Plan obligations	**25.5**	**—**	**—**	**—**	**25.5**
Total financial liabilities	**$ 25.5**	**$ 78.1**	**$ —**	**$ (1.4)**	**$ 102.2**
	December 31, 2019				
Financial Assets					
Fair value of derivative contracts – short-term	$ —	$ 1.5	$ —	$ —	$ 1.5
Fair value of derivative contracts – long-term	—	0.2	—	—	0.2
Fair value of Rabbi Trust marketable securities	23.1	—	—	—	23.1
Total financial assets	$ 23.1	$ 1.7	$ —	$ —	$ 24.8
Financial Liabilities					
Fair value of derivative contracts – short-term	$ —	$ 18.7	$ —	$ —	$ 18.7
Fair value of derivative contracts – long-term	—	0.5	—	—	0.5
Fair value of Wrap Plan obligations	26.8	—	—	—	26.8
Total financial liabilities	$ 26.8	$ 19.2	$ —	$ —	$ 46.0

[1] The Company nets its derivative contract assets and liabilities outstanding with the same counterparty on the balance sheets for the contracts that contain netting provisions. Refer to Note 6 – Derivative Contracts for more information regarding the Company's derivative contracts.

The following table discloses the fair value and related carrying amount of long-term debt not disclosed in other Notes to the Consolidated Financial Statements:

	Carrying Amount	Level 1 Fair Value	Carrying Amount	Level 1 Fair Value
	December 31, 2020		December 31, 2019	
Financial Liabilities	(in millions)			
Long-term debt	**$ 1,591.3**	**$ 1,702.8**	$ 2,015.6	$ 2,029.4

The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and checks outstanding in excess of cash balances approximate fair value. The fair value of fixed-rate long-term debt is based on the trading levels and dollar prices for the Company's debt at the end of the year. At times when the Company has outstanding debt under the credit facility, the carrying amount of variable-rate long-term debt approximates fair value because the floating interest rate paid on such debt is set for periods of one month or less.

The initial measurement of ARO at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of ARO include plugging costs and reserve lives. A reconciliation of the Company's ARO is presented in Note 4 – Asset Retirement Obligations.

Nonrecurring Fair Value Measurements

The provisions of the fair value measurement standard are also applied to the Company's nonrecurring measurements. The Company reviews its proved oil and gas properties and operating lease ROU assets for potential impairment when events and changes in circumstances indicate that the carrying amount of such property may not be recoverable. If the asset's carrying value exceeds the related undiscounted future net cash flows, the fair value of property is measured utilizing the income approach, and utilizing inputs that are primarily based upon internally developed cash flow models discounted at an appropriate weighted average cost of capital. In addition, the signing of merger or purchase and sale agreements could also trigger an impairment of proved properties. For assets subject to a merger or purchase and sale agreement, the evaluation of terms of the merger or purchase and sale agreement are used as an indicator of fair value. If a range is estimated for the amount of possible future cash flows, the fair value of property is measured utilizing a probability-weighted approach whereas the likelihood of possible outcomes is taken into consideration. Specific to the Terminated Williston Basin Divestiture, the Company obtained a Black-Scholes-Merton estimate of the value of the contractual rights to receive up to 5.8 million shares of the buyer's common stock at December 31, 2018. The estimated fair value of these contractual rights at December 31, 2018 was determined using a five-year contractual period, a 5% risk-free interest rate and a 49.3% weighted-average expected price volatility. Given the unobservable nature of the inputs, fair value calculations associated with proved oil and gas property impairments are considered Level 3 within the fair value hierarchy. During the year ended December 31, 2019, the Company recorded impairments of $5.0 million related to an office building lease. During the year ended December 31, 2018, the Company recorded impairments on certain proved oil and gas properties of $1,524.6 million resulting in a reduction of the associated carrying value to fair value. Refer to Note 1 – Summary of Significant Accounting Policies for more information on impairment of oil and gas properties.

Note 6 – Derivative Contracts

QEP has established policies and procedures for managing commodity price volatility through the use of derivative instruments. In the normal course of business, QEP uses commodity price derivative instruments to reduce the impact of potential downward movements in commodity prices on cash flow, returns on capital investment, and other financial results. However, these instruments typically limit gains from favorable price movements. The volume of production subject to commodity derivative instruments and the mix of the instruments are frequently evaluated and adjusted by management in response to changing market conditions. QEP may enter into commodity derivative contracts for up to 100% of forecasted production, but generally, QEP enters into commodity derivative contracts for approximately 50% to 75% of its forecasted annual production by the end of the first quarter of each fiscal year. QEP typically enters into commodity derivative transactions covering a substantial, but varying, portion of its anticipated oil and gas production for the next 12 to 24 months. In addition, QEP has historically entered into commodity derivative contracts on a portion of its storage transactions. QEP does not enter into commodity derivative contracts for speculative purposes.

QEP uses commodity derivative instruments known as fixed-price swaps or costless collars to realize a known price or price range for a specific volume of production delivered into a regional sales point. QEP's commodity derivative instruments do not require the physical delivery of oil or gas between the parties at settlement. All transactions are settled in cash with one party paying the other for the net difference in prices, multiplied by the contract volume, for the settlement period. Oil price derivative instruments are typically structured as NYMEX fixed-price swaps or costless collars based at Cushing, Oklahoma. Gas price derivative instruments are typically structured as fixed-price swaps or costless collars at NYMEX HH or regional price indices. QEP enters into oil and gas basis swaps to achieve a fixed-price swap for a portion of its oil and gas sales at prices that reference specific regional index prices. QEP also enters into calendar month average (CMA) rolls in order to reduce pricing volatility between the trade month and the physical delivery month for a portion of its oil sales at prices that reference specific regional index prices.

QEP does not currently have any commodity derivative transactions that have margin requirements or collateral provisions that would require payments prior to the scheduled settlement dates. QEP's commodity derivative contract counterparties are typically financial institutions and energy trading firms with investment-grade credit ratings. QEP routinely monitors and manages its exposure to counterparty risk by requiring specific minimum credit standards for all counterparties, actively monitoring counterparties' public credit ratings and avoiding the concentration of credit exposure by transacting with multiple counterparties. The Company has master-netting agreements with some counterparties that allow the offsetting of receivables and payables in a default situation.

Derivative Contracts – Production

The following table presents QEP's volumes and average prices for its commodity derivative swap contracts as of December 31, 2020:

Year	Index	Total Volumes	Average Swap Price per Unit
		(in millions)	
Oil sales		(bbls)	($/bbl)
2021 (January - June)	NYMEX WTI	7.3	$ 44.54
2021 (July - December)	NYMEX WTI	6.3	$ 42.64
2022 (January - June)	NYMEX WTI	0.2	$ 45.00
Gas Sales		(MMbtu)	($/MMbtu)
2021	IF Waha	18.3	$ 1.92
2021	NYMEX HH	9.1	$ 2.44

QEP uses oil basis swaps, combined with NYMEX WTI fixed price swaps, to achieve fixed price swaps for the location at which it sells its physical production. QEP uses CMA rolls, combined with NYMEX CMA or NYMEX WTI fixed price swaps, to reduce the volatility in oil pricing between the trade month and the physical delivery month. The following table presents details of QEP's oil basis swaps as of December 31, 2020:

Year	Index	Basis	Total Volumes	Weighted-Average Differential
			(in millions)	
Oil sales			(bbls)	($/bbl)
2021	NYMEX WTI	Argus WTI Midland	5.8	$ 0.88
2021	NYMEX CMA	Argus WTI	1.5	$ 0.00
2021	NYMEX WTI	NYMEX Roll	1.8	$ (0.05)

The following table presents QEP's volumes and average prices for its commodity derivative costless oil collars as of December 31, 2020:

Year	Index	Total Volumes	Average Price Floor	Average Price Ceiling
		(in millions)		
		(bbls)	($/bbl)	($/bbl)
2021 (January - June)	NYMEX WTI	0.3	$ 40.73	$ 50.17
2021 (July - December)	NYMEX WTI	0.8	$ 40.16	$ 49.89

The effects of the change in fair value and settlement of QEP's derivative contracts recorded in "Realized and unrealized gains (losses) on derivative contracts" on the statements of operations are summarized in the following table:

	Year Ended December 31,		
Derivative contracts	**2020**	2019	2018
Realized gains (losses) on commodity derivative contracts		(in millions)	
Production			
Oil derivative contracts	**$ 296.4**	$ (32.2)	$ (153.4)
Gas derivative contracts	**(4.5)**	(2.9)	(5.0)
Gas Storage			
Gas derivative contracts	**—**	—	0.3
Realized gains (losses) on commodity derivative contracts	**291.9**	(35.1)	(158.1)
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**(48.7)**	(139.8)	277.0
Gas derivative contracts	**(10.5)**	(0.3)	(22.3)
Gas Storage			
Gas derivative contracts	**—**	—	(0.3)
Unrealized gains (losses) on commodity derivative contracts	**(59.2)**	(140.1)	254.4
Total realized and unrealized gains (losses) on commodity derivative contracts related to production and storage contracts	**$ 232.7**	$ (175.2)	$ 96.3
Derivatives associated with divestitures			
Unrealized gains (losses) on commodity derivative contracts			
Production			
Oil derivative contracts	**$ —**	$ —	$ (2.7)
Gas derivative contracts	**—**	1.8	—
NGL derivative contracts	**—**	—	(3.2)
Unrealized gains (losses) on commodity derivative contracts related to divestitures[(1)(2)]	**$ —**	$ 1.8	$ (5.9)
Total realized and unrealized gains (losses) on commodity derivative contracts	**$ 232.7**	$ (173.4)	$ 90.4

(1) During the year ended December 31, 2019, the unrealized gains (losses) on commodity derivative contracts related to the Haynesville Divestiture are comprised of derivatives included as part of the Haynesville/Cotton Valley purchase and sale agreement, which were subsequently novated to the buyer upon the closing of the sale in January 2019. Refer to Note 3 – Acquisitions and Divestitures for more information. The unrealized gains (losses) on commodity derivatives associated with the Haynesville Divestiture are offset by an equal amount recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statements of operations.

(2) During the year ended December 31, 2018, the unrealized gains (losses) on commodity derivative contracts related to the Uinta Basin Divestiture are comprised of derivatives entered into in conjunction with the execution of the Uinta Basin purchase and sale agreement, which were subsequently novated to the buyer upon the closing of the sale in September 2018. Refer to Note 3 – Acquisitions and Divestitures for more information. The unrealized gains (losses) on commodity derivatives associated with the Uinta Basin Divestiture are offset by an equal amount recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statements of operations.

Note 7 – Leases

Adoption of ASC Topic 842, *Leases*

On January 1, 2019 QEP adopted ASC Topic 842, *Leases*, using the modified retrospective approach, which was applied to historical leases that were still effective as of January 1, 2019. Results for the reporting periods beginning with January 1, 2019, are presented in accordance with ASC Topic 842, while prior period amounts are reported in accordance with historical accounting treatment under ASC Topic 840, *Leases.*

In accordance with the adoption of ASC Topic 842, *Leases*, QEP now records a net operating lease ROU asset and operating lease liability on the balance sheets for all operating leases with a contract term in excess of 12 months. Prior to the adoption of ASC Topic 842, these same leases were treated as operating leases under Topic ASC 840 and therefore were not recorded on the December 31, 2018 balance sheet. There was no impact to retained earnings and no significant impact on the statements of operations or statements of cash flows as a result of adopting ASC Topic 842.

Lease Recognition

QEP enters into contractual lease arrangements to rent office space, compressors, generators, drilling rigs and other equipment from third-party lessors. ROU assets represent QEP’s right to use an underlying asset for the lease term and lease liabilities represent QEP’s obligation to make future lease payments arising from the lease. Operating lease ROU assets and liabilities are recorded at commencement date based on the present value of lease payments over the lease term. Leases with an initial term of 12 months or less are not recorded on the balance sheets. The Company recognizes lease expense for these short-term leases on a straight-line basis over the lease term. With the exception of generators, QEP does not account for lease components separately from the non-lease components. The contractual consideration provided under QEP's leased generators is allocated between lease components, such as equipment, and non-lease components, such as maintenance service fees, based on estimated costs from the vendor. QEP uses the implicit interest rate when readily determinable. However, most of QEP's lease agreements do not provide an implicit interest rate. As such, QEP uses its incremental borrowing rate based on the information available at commencement date of the contract in determining the present value of future lease payments. The incremental borrowing rate is calculated using a risk-free interest rate adjusted for QEP's risk. The operating lease ROU asset also includes any lease incentives received in the recognition of the present value of future lease payments. Certain of QEP's leases may also include escalation clauses or options to extend or terminate the lease. These options are included in the present value recorded for the leases when it is reasonably certain that QEP will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term.

QEP determines if an arrangement is a lease at inception of the contract and records the resulting operating lease asset on the balance sheets as “Operating lease right-of-use assets, net” with offsetting liabilities recorded as “Current operating lease liabilities” and “Operating lease liabilities.” QEP recognizes a lease in the financial statements when the arrangement either explicitly or implicitly involves property, plant, or equipment (PP&E), the contract terms are dependent on the use of the PP&E, and QEP has the ability or right to operate the PP&E or to direct others to operate the PP&E and receive the majority of the economic benefits of the assets. As of December 31, 2020 and 2019, QEP does not have any financing leases.

Lease costs represent the straight-line lease expense of ROU assets and short-term leases. The components of lease cost are classified as follows:

	As of December 31,	
	2020	**2019**
	(in millions)	
Lease Cost included in the Consolidated Balance Sheets		
Property, Plant and Equipment additions[1]	**$ 11.7**	$ 13.8

	Year Ended December 31,	
	2020	2019
	(in millions)	
Lease Cost included in the Consolidated Statement of Operations		
Lease operating expense[2]	**$ 14.0**	$ 11.9
Gathering and other expense[2]	**5.7**	7.7
General and administrative[2]	**6.0**	5.7
Total lease cost	**$ 25.7**	$ 25.3

(1) Represents short-term lease capital expenditures related to drilling rigs for the years ended December 31, 2020 and 2019. These costs are capitalized as a part of "Proved properties" on the balance sheets.

(2) Amounts for the year ended December 31, 2018 are not presented as 2018 amounts have not been adjusted under the modified retrospective method for ASC Topic 842 - Leases, which the Company adopted in 2019. During the year ended December 31, 2018, $30.3 million of expense from operating leases was reported in accordance with historical accounting treatment under ASC Topic 840, *Leases.*

Lease term and discount rate related to the Company's leases are as follows:

	As of December 31,	
	2020	2019
Weighted-average remaining lease term (years)	3.6	5.4
Weighted-average discount rate	7.2 %	8.0 %

As of December 31, 2020, the maturity analysis for long-term operating leases under the scope of ASC 842 is as follows:

Year	**December 31, 2020**
	(in millions)
2021	$ **24.9**
2022	**17.2**
2023	**11.5**
2024	**2.4**
2025	**0.8**
After 2025	**2.9**
Less: Interest[(1)]	**(6.7)**
Present Value of Lease Liabilities[(2)]	$ **53.0**

(1) Calculated using the estimated or stated interest rate for each lease.
(2) Of the total present value of lease liabilities, $21.7 million was recorded in "Current operating lease liabilities" and $31.3 million was recorded in "Operating lease liabilities" on the balance sheets as of December 31, 2020.

Note 8 – Restructuring

In February 2018, QEP's Board approved certain strategic and financial initiatives. In February 2019, QEP's Board commenced a comprehensive review of strategic alternatives to maximize shareholder value. In connection with these activities, QEP has incurred various restructuring costs associated with contractual termination benefits including severance, accelerated vesting of share-based compensation and other expenses. The termination benefits have been accounted for under ASC 712, *Compensation – Nonretirement Postemployment Benefits* and ASC 718, *Compensation – Stock Compensation*.

Restructuring costs recognized are summarized below:

	Year Ended December 31, 2020			
	Total recognized	Recognized in "General and administrative"	Recognized in "Net (gain) loss from asset sales, inclusive of restructuring costs"	Recognized in "Interest and other (income) expense"
	(in millions)			
Termination benefits	$ **1.0**	$ **1.0**	$ **—**	$ **—**
Accelerated share-based compensation	**0.5**	**0.5**	**—**	**—**
Retention expense (including share-based compensation)	**0.4**	**0.4**	**—**	**—**
Total restructuring costs	$ **1.9**	$ **1.9**	$ **—**	$ **—**

	Year Ended December 31, 2019			
	Total recognized	Recognized in "General and administrative"	Recognized in "Net (gain) loss from asset sales, inclusive of restructuring costs"	Recognized in "Interest and other (income) expense"
	(in millions)			
Termination benefits	$ 12.3	$ 12.2	$ 0.1	$ —
Office lease termination costs	0.6	0.6	—	—
Accelerated share-based compensation	12.6	11.1	1.5	—
Retention expense (including share-based compensation)	19.5	19.5	—	—
Pension and Medical Plan curtailment	1.2	—	(0.2)	1.4
Total restructuring costs	$ 46.2	$ 43.4	$ 1.4	$ 1.4

	Year Ended December 31, 2018			
	Total recognized	Recognized in "General and administrative"	Recognized in "Net (gain) loss from asset sales, inclusive of restructuring costs"	Recognized in "Interest and other (income) expense"
	(in millions)			
Termination benefits	$ 32.3	$ 25.7	$ 6.6	$ —
Office lease termination costs	1.0	1.0	—	—
Accelerated share-based compensation	11.0	8.8	2.2	—
Retention expense (including share-based compensation)	18.8	18.8	—	—
Pension and Medical Plan curtailment	0.1	—	(0.2)	0.3
Total restructuring costs	$ 63.2	$ 54.3	$ 8.6	$ 0.3

	Costs recognized from inception through December 31, 2020 [1]	Total remaining costs expected to be incurred
	(in millions)	
Termination benefits	**$ 45.6**	**$ —**
Office lease termination costs	**1.6**	**—**
Accelerated share-based compensation	**24.1**	**—**
Retention expense (including share-based compensation)	**38.7**	**—**
Pension and Medical Plan curtailment	**1.3**	**—**
Total restructuring costs	**$ 111.3**	**$ —**

[1] Represents costs incurred since February 2018 when QEP's Board approved certain strategic and financial initiatives.

The following table is a reconciliation of QEP's restructuring liability, which is included within "Accounts payable and accrued expenses" on the balance sheets.

	Restructuring liability					
	Termination benefits	Office lease termination costs	Accelerated share-based compensation	Retention expense	Pension curtailment	Total
	(in millions)					
Balance at December 31, 2019	$ 1.2	$ —	$ —	$ 6.5	$ —	$ 7.7
Costs incurred and charged to expense	**1.0**	**—**	**0.5**	**0.4**	**—**	**1.9**
Costs paid or otherwise settled	**(2.2)**	**—**	**(0.5)**	**(6.9)**	**—**	**(9.6)**
Balance at December 31, 2020	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

Note 9 – Debt

As of the indicated dates, the principal amount of QEP's debt consisted of the following:

	December 31,	
	2020	2019
	(in millions)	
Revolving Credit Facility due 2022	**$ —**	$ —
6.875% Senior Notes due 2021	**—**	382.4
5.375% Senior Notes due 2022	**465.1**	500.0
5.25% Senior Notes due 2023	**636.8**	650.0
5.625% Senior Notes due 2026	**500.0**	500.0
Less: unamortized discount and unamortized debt issuance costs	**(10.6)**	(16.8)
Total long-term debt outstanding	**$ 1,591.3**	$ 2,015.6

Of the total debt outstanding on December 31, 2020, the 5.375% Senior Notes due October 1, 2022 and the 5.25% Senior Notes due May 1, 2023, will mature within the next five years. In addition, the revolving credit facility matures on September 1, 2022.

Credit Facility

In June 2020, QEP entered into the Eighth Amendment to its credit agreement, which, among other things, reduced the aggregate principal amount of commitments to $850.0 million, requires the Company's material subsidiaries to guarantee the obligations under the credit agreement, including certain swap obligations, and modified the leverage ratio and present value financial covenants, such that they only pertain to net priority guaranteed debt (primarily consisting of borrowings under the credit facility and letters of credit). The amended credit agreement also provides the ability to use up to $500.0 million of loan proceeds to repurchase outstanding senior notes, provides the ability to issue subsidiary guarantees of up to $500.0 million of unsecured debt, with such guarantees being subordinated to the obligations under the credit agreement, and may limit the Company’s ability to make certain restricted payments, including dividends. The amended credit agreement, which matures on September 1, 2022, provides for borrowings at short-term interest rates and contains customary covenants and restrictions and contains financial covenants (that are defined in the credit agreement) that limit the amount of debt the Company can incur and may limit the amount available to be drawn under the credit facility including: (i) a minimum liquidity amount of at least $100.0 million, (ii) a net priority guaranteed leverage ratio under which net priority guaranteed debt may not exceed 2.50 times consolidated EBITDAX (as defined in the credit agreement), and (iii) a present value coverage ratio under which the present value of the Company's proved reserves must exceed net priority guaranteed debt by at least 1.50 times. At December 31, 2020 and 2019, QEP was in compliance with the covenants under the credit agreement. During the year ended December 31, 2020, the Company recorded a $1.5 million loss associated with the write-off of non-cash deferred financing costs as part of amending the credit facility and recorded the loss within "Gain (loss) from early extinguishment of debt" on the statements of operations.

During the years ended December 31, 2020 and 2019, QEP's weighted-average interest rates on borrowings from its credit facility were 2.60% and 4.73%, respectively. As of December 31, 2020, QEP had no borrowings outstanding and $14.1 million in letters of credit outstanding under the credit facility. As of December 31, 2019, QEP had no borrowings outstanding and $2.9 million in letters of credit outstanding under the credit facility.

Senior Notes
At December 31, 2020, the Company had $1,601.9 million principal amount of senior notes outstanding with maturities ranging from October 1, 2022 to March 1, 2026, and coupons ranging from 5.25% to 5.625%. The senior notes pay interest semi-annually, are unsecured senior obligations and rank equally with all of our other existing and future unsecured and senior obligations. QEP may redeem some or all of its senior notes at any time before their maturity at a redemption price based on a make-whole amount plus accrued and unpaid interest to the date of redemption. The indenture governing QEP's senior notes contains customary events of default and covenants that may limit QEP's ability to, among other things, place liens on its property or assets. During the year ended December 31, 2020, QEP repurchased, at a discount, $107.1 million in principal amount of its 6.875% Senior Notes due March 1, 2021, $34.9 million in principal amount of its 5.375% Senior Notes due October 1, 2022, and $13.2 million in principal amount of its 5.25% Senior Notes due May 1, 2023, resulting in a $27.1 million gain from early extinguishment of debt. In addition, QEP redeemed the remaining $275.3 million in principal amount of its 6.875% Senior Notes due March 1, 2021, resulting in a loss on early extinguishment of debt of $7.4 million. In total, during the year ended December 31, 2020, the Company recorded a $19.7 million gain in "Gain (loss) from early extinguishment of debt" in the statements of operations related to the redemption and repurchase of senior notes.

Note 10 – Commitments and Contingencies

The Company is involved in various commercial and regulatory claims, litigation and other legal proceedings that arise in the ordinary course of its business. In each reporting period, the Company assesses these claims in an effort to determine the degree of probability and range of possible loss for potential accrual in its financial statements. In accordance with ASC 450, *Contingencies*, an accrual is recorded for a loss contingency when its occurrence is probable and damages are reasonably estimable based on the anticipated most likely outcome or the minimum amount within a range of possible outcomes.

Legal proceedings are inherently unpredictable and unfavorable resolutions can occur. Assessing contingencies is highly subjective and requires judgment about uncertain future events. When evaluating contingencies related to legal proceedings, the Company may be unable to estimate losses due to a number of factors, including potential defenses, the procedural status of the matter in question, the presence of complex legal and/or factual issues, the ongoing discovery and/or development of information important to the matter.

Mandan, Hidatsa and Arikara Nation ("MHA Nation") Title Dispute – In June 2018, the MHA Nation notified QEP of its position that QEP has no valid lease covering certain minerals underlying the Missouri and Little Missouri Riverbeds on the Fort Berthold Reservation in North Dakota. The MHA Nation also passed a resolution purporting to rescind those portions of QEP's IMDA lease covering the disputed minerals underlying the Missouri River. In May 2020, the Office of the Solicitor of the United States Department of the Interior issued an opinion finding that the State of North Dakota, not the MHA nation, is the legal owner of the minerals underlying the Missouri River. The MHA Nation has filed actions in two federal courts seeking to overturn the May 2020 decision.

Overriding Royalty Interest Litigation – In July 2019, owners of small overriding royalty interests in certain wells in the South Antelope oil and gas field in North Dakota filed suit against QEP, alleging QEP has improperly taken deductions for post-production expenses.

In many cases, the Company is unable to make an estimate of the range of reasonably possible loss related to its contingencies. To the extent that the Company can reasonably estimate losses for contingencies where the risk of material loss (in excess of accruals, if any) is reasonably possible, the Company estimates such losses to be in a range of zero to approximately $10.0 million, in the aggregate.

Commitments

QEP has contracted for gathering, processing and firm transportation services with various third parties. Market conditions, drilling activity and competition may prevent full utilization of the contractual capacity. In addition, QEP has contracts with third parties who provide drilling services. Annual payments and the corresponding years for gathering, processing, transportation, drilling and fractionation contracts are as follows:

Year		Amount
		(in millions)
2021	$	28.0
2022	$	22.4
2023	$	12.2
2024	$	6.9
2025	$	4.9
After 2025	$	2.1

Note 11 – Share-Based and Long-Term Compensation

In 2018, QEP's Board and shareholders approved the QEP Resources, Inc. 2018 Long-Term Incentive Plan (LTIP), which replaces the 2010 Long-Term Stock Incentive Plan (LTSIP) and provides for the issuance of up to 10.0 million shares such that the Board may grant long-term incentive compensation. QEP issues restricted share awards, restricted cash awards and restricted share units under its LTSIP or LTIP and issues performance share unit awards under its Cash Incentive Plan (CIP) to certain officers, employees, and non-employee directors. QEP historically issued stock options under its LTSIP. Grants issued prior to May 15, 2018 are under the LTSIP and the grants issued on or after May 15, 2018 are under the LTIP. QEP recognizes the expense over the vesting periods for the stock options, restricted share awards, restricted cash awards, restricted share units and performance share units. There were 2.9 million shares available for future grants under the LTIP at December 31, 2020.

Share-based compensation expense is generally recognized within "General and administrative" expense on the statements of operations and is summarized in the table below.

	Year Ended December 31,		
	2020[1][2]	2019[3]	2018[4]
		(in millions)	
Non-cash share-based compensation			
Stock options	**$ —**	$ 0.4	$ 1.2
Restricted share awards	**12.4**	20.4	27.5
Total non-cash share-based compensation	**12.4**	20.8	28.7
Cash share-based compensation			
Restricted cash awards	**1.7**	—	—
Performance share units	**1.0**	4.3	8.1
Restricted share units	**0.1**	0.3	0.1
Total cash share-based compensation	**2.8**	4.6	8.2
Total share-based compensation expense	**$ 15.2**	$ 25.4	$ 36.9

(1) During the year ended December 31, 2020, the Company incurred $0.4 million of share-based compensation expense related to restricted share awards in which vesting was accelerated in accordance with the Merger Agreement. Refer to Note 1 – Summary of Significant Accounting Policies for more information on the Merger Agreement.

(2) During the year ended December 31, 2020, the Company incurred $0.5 million of share-based compensation expense related to the acceleration of vesting that occurred as part of the restructuring program and is included in the table above. Refer to Note 8 – Restructuring for more information.

(3) During the year ended December 31, 2019, the Company recorded $12.6 million of share-based compensation expense related to the acceleration of vesting that occurred as part of the restructuring program. Of the $12.6 million, $1.5 million was recorded in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statement of operations, and the remaining $11.1 million is included in the table above. Refer to Note 8 – Restructuring for more information.

(4) During the year ended December 31, 2018, the Company recorded $11.0 million of share-based compensation expense related to the acceleration of vesting that occurred as part of the restructuring program. Of the $11.0 million, $2.2 million was recorded in "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statement of operations, and the remaining $8.8 million is included in the table above. Refer to Note 8 – Restructuring for more information.

Stock Options

QEP used the Black-Scholes-Merton mathematical model to estimate the fair value of stock option awards at the date of grant. Fair value calculations relied upon subjective assumptions used in the mathematical model and may not be representative of future results. The Black-Scholes-Merton model, which was intended for calculating the value of options not traded on an exchange, was historically used by the Company when QEP granted stock options. The Company utilized the "simplified" method to estimate the expected term of the stock options granted as there was limited historical exercise data available in estimating the expected term of the stock options. QEP used a historical volatility method to estimate the fair value of stock options awards and the risk-free interest rate was based on the yield on U.S. Treasury strips with maturities similar to those of the expected term of the stock options. The stock options typically vest in equal installments over three years from the grant date and are exercisable immediately upon vesting through the seventh anniversary of the grant date. To fulfill options exercised, QEP either reissues treasury stock or issues new shares. The Company recognizes forfeitures of stock options as they occur. During the years ended December 31, 2020, 2019 and 2018, QEP did not issue stock options.

Stock option transactions under the terms of the LTSIP are summarized below:

	Options Outstanding	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
		(per share)	(in years)	(in millions)
Outstanding at December 31, 2019	1,802,387	$ 20.87		
Exercised	**—**	**—**		
Cancelled	**(311,203)**	**30.08**		
Outstanding at December 31, 2020	**1,491,184**	**$ 18.94**	**1.77**	**$ —**
Options Exercisable at December 31, 2020	**1,491,184**	**$ 18.94**	**1.77**	**$ —**
Unvested Options at December 31, 2020	**—**	**$ —**	**0.00**	**$ —**

During the years ended December 31, 2020 and 2019, there were no exercises of stock options. The total intrinsic value (the difference between the market price at the exercise date and the exercise price) of stock options exercised was $0.1 million during the year ended December 31, 2018. The Company recognized $1.1 million and $2.3 million of income tax expense for the years ended December 31, 2020 and 2019, respectively, and no income tax expense for the year ended December 31, 2018. As of December 31, 2020, there was no unrecognized compensation cost related to stock options granted under the LTSIP.

Restricted Share Awards

Restricted share award grants typically vest in equal installments over three years from the grant date. The grant date fair value is determined based on the closing bid price of the Company's common stock on the grant date. The Company recognizes restricted share forfeitures as they occur. The total fair value of restricted share awards that vested during the years ended December 31, 2020, 2019 and 2018, was $4.5 million, $32.5 million and $21.5 million, respectively. The Company recognized $2.5 million and $5.4 million of income tax expense for the years ended December 31, 2020 and 2019, respectively, and no tax impact for the year ended December 31, 2018. The weighted-average grant date fair value of restricted share awards granted was $2.10 per share, $7.72 per share and $9.56 per share for the years ended December 31, 2020, 2019 and 2018, respectively. As of December 31, 2020, $7.0 million of unrecognized compensation cost related to restricted share awards granted under the LTSIP is expected to be recognized over a weighted-average vesting period of 1.93 years.

Transactions involving restricted share awards under the terms of the LTSIP and LTIP are summarized below:

	Restricted Share Awards Outstanding	Weighted-Average Grant Date Fair Value
		(per share)
Unvested balance at December 31, 2019	2,845,033	$ 8.67
Granted	**5,080,589**	**2.10**
Vested	**(2,240,899)**	**7.09**
Forfeited	**(109,925)**	**4.79**
Unvested balance at December 31, 2020	**5,574,798**	**$ 3.39**

Restricted Cash Awards

Beginning in March 2020, QEP issued restricted cash awards under its LTIP to certain employees. Restricted cash award grants vest in equal installments over three years from the grant date. The Company recognizes restricted cash forfeitures as they occur. There were no restricted cash awards granted or outstanding during the year ended December 31, 2019. As of December 31, 2020, $1.6 million of unrecognized compensation expense related to restricted cash awards granted under the LTIP is expected to be recognized over a weighted-average vesting period of 2.25 years.

Transactions involving restricted cash awards under the terms of the LTIP are summarized below:

	Restricted Cash Awards Outstanding
Unvested balance at December 31, 2019	$ —
Granted	**3,249,925**
Vested	**(7,000)**
Forfeited	**(75,250)**
Unvested balance at December 31, 2020	**$ 3,167,675**

Performance Share Units

The payouts for performance share units are dependent upon the Company's total shareholder return compared to a group of its peers over three years. The awards are denominated in share units and have historically been paid in cash. The Company has the option to settle earned awards in cash or shares of common stock under the Company's LTIP; however, as of December 31, 2020, the Company expects to settle all awards in cash under the CIP. These awards are classified as liabilities and are included within "Other long-term liabilities" on the balance sheets. As these awards are dependent upon the Company's total shareholder return and stock price, they are measured at fair value at the end of each reporting period. The Company paid $0.3 million, $13.0 million and $2.8 million for vested performance share units during the years ended December 31, 2020, 2019 and 2018, respectively. The weighted-average grant date fair value of the performance share units granted during the years ended December 31, 2020, 2019 and 2018, was $2.17, $7.93, and $9.55 per share, respectively. As of December 31, 2020, $2.1 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of performance shares granted, is expected to be recognized over a weighted-average vesting period of 1.91 years.

Transactions involving performance share units under the terms of the CIP are summarized below:

	Performance Share Units Outstanding	Weighted-Average Grant Date Fair Value
		(per share)
Unvested balance at December 31, 2019	625,922	$ 9.04
Granted	**1,926,026**	**2.17**
Vested	**(96,734)**	**13.06**
Unvested balance at December 31, 2020	**2,455,214**	**$ 3.56**

Restricted Share Units
Employees may elect to defer their grants of restricted share awards and these deferred awards are designated as restricted share units. Restricted share units vest over three years and are deferred into the Company's Wrap Plan at the time of grant. These awards are ultimately paid in cash, are classified as liabilities in "Other long-term liabilities" on the balance sheets and are measured at fair value at the end of each reporting period. The weighted-average grant date fair value of the restricted share units was $2.08, $7.87 and $9.55 per share for the years ended December 31, 2020, 2019 and 2018, respectively. As of December 31, 2020, $0.1 million of unrecognized compensation cost, which represents the unvested portion of the fair market value of restricted share units granted, is expected to be recognized over a weighted-average vesting period of 0.83 years.

Transactions involving restricted share units under the terms of the LTSIP and LTIP are summarized below:

	Restricted Share Units Outstanding	Weighted-Average Grant Date Fair Value
		(per share)
Unvested balance at December 31, 2019	34,393	$ 8.16
Granted	**76,083**	**2.08**
Vested and paid	**(26,770)**	**8.20**
Unvested balance at December 31, 2020	**83,706**	**$ 2.62**

Note 12 – Employee Benefits

Pension and Other Postretirement Benefits
The Company provides pension and other postretirement benefits to certain employees through three benefit plans: the QEP Resources, Inc. Retirement Plan (Pension Plan), the Supplemental Executive Retirement Plan (SERP), and a postretirement medical plan (Medical Plan).

The Pension Plan is a closed, qualified, defined-benefit pension plan that is funded and provides pension benefits to certain QEP employees, which, as of December 31, 2020, covers two active and suspended participants, or 1%, of QEP's active employees, and 212 participants that are retired or were terminated and vested. Pension Plan benefits are based on the employee's age at retirement, years of service as of the earlier of the participant's termination of employment or December 31, 2015, and highest earnings in a consecutive 72 semi-monthly pay period during the 10 years preceding termination of employment or, if earlier, December 31, 2015. The Pension Plan was amended and restated in June 2015, is closed to new participants and was frozen such that active participants do not earn any additional accrued benefits on or after January 1, 2016. During the year ended December 31, 2020, the Company made contributions of $4.0 million to the Pension Plan and expects to contribute approximately $4.0 million to the Pension Plan in 2021. Contributions to the Pension Plan increase plan assets.

The SERP is a nonqualified retirement plan that is unfunded and provides pension benefits to certain QEP employees. SERP benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semi-monthly pay period during the 10 years preceding the participant's termination of employment. During the year ended December 31, 2020, the Company made contributions of $9.7 million to its SERP and expects to contribute approximately $3.1 million in 2021. Contributions to the SERP are used to fund current benefit payments. The SERP was amended and restated in June 2015 and is closed to new participants effective January 1, 2016.

The Medical Plan is a self-insured plan. It is unfunded and provides other postretirement benefits including certain health care and life insurance benefits for certain retired QEP employees. The Medical Plan was originally provided only to employees hired by Questar Corporation before January 1, 1997. Of the two active, pension eligible employees, neither is eligible for the Medical Plan when they retire. As of December 31, 2020, 27 retirees are enrolled in the Medical Plan. The Company has capped its exposure to increasing medical costs by paying a fixed dollar monthly contribution toward these retiree benefits. The Company's contribution is prorated based on an employee's years of service at retirement; only those employees with 25 or more years of service receive the maximum company contribution. During the year ended December 31, 2020, the Company made contributions of $0.7 million and expects to contribute approximately $0.2 million of benefits in 2021. At December 31, 2020 and 2019, QEP's accumulated benefit obligation exceeded the fair value of its qualified retirement plan assets.

In February 2017, the Company changed the eligibility requirements for active employees eligible for the Medical Plan, as well as retirees currently enrolled. Effective July 1, 2017, the Company no longer offers the Medical Plan to a retiree and spouse that are both Medicare eligible. In addition, the Company no longer offers life insurance to individuals retiring on or after July 1, 2017.

The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the statements of operations. All other expenses related to the Pension Plan, SERP and Medical Plan are recognized within "Interest and other income (expense)" on the statements of operations.

The Company's execution of its 2018 and 2019 strategic initiatives, including divestitures and corporate restructurings, triggered curtailments related to the Pension Plan, SERP and/or Medical Plan at the closing of the various transactions. Refer to Note 8 – Restructuring for more information. Curtailments were included in "Interest and other income (expense)" and "Net gain (loss) from asset sales, inclusive of restructuring costs" on the statements of operations depending on the associated participants triggering the curtailment and are summarized in the following table:

	Year ended December 31,		
Statements of Operations Line	**2020**	2019	2018
Interest and other income (expense)	**$ —**	$ (1.4)	$ (0.3)
Net gain (loss) from asset sales, inclusive of restructuring costs	—	0.2	0.2
Total curtailment gain (loss)	**$ —**	$ (1.2)	$ (0.1)

The accumulated benefit obligation for the Pension and SERP defined-benefit pension plans was $135.3 million and $135.2 million as of December 31, 2020 and 2019, respectively.

The following table sets forth changes in the benefit obligations and fair value of plan assets for the Company's Pension Plan, SERP and Medical Plan for the years ended December 31, 2020 and 2019, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2020 and 2019:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2020	2019	**2020**	2019
Change in benefit obligation	(in millions)			
Benefit obligation at January 1,	**$ 135.2**	$ 122.1	**$ 2.6**	$ 2.5
Service cost	**—**	0.3	**—**	—
Interest cost	**4.1**	4.8	**0.1**	0.1
Curtailments	**—**	1.2	**—**	—
Benefit payments	**(10.3)**	(6.2)	**(0.7)**	(0.9)
Plan amendments	**—**	—	**—**	—
Actuarial loss (gain)	**11.7**	13.0	**0.7**	0.9
Settlement loss	**(5.4)**	—	**—**	—
Benefit obligation at December 31,	**$ 135.3**	$ 135.2	**$ 2.7**	$ 2.6
Change in plan assets				
Fair value of plan assets at January 1,	**$ 113.9**	$ 93.3	**$ —**	$ —
Actual return on plan assets	**16.1**	21.3	**—**	—
Company contributions to the plan	**13.7**	5.5	**0.7**	0.9
Benefit payments	**(10.3)**	(6.2)	**(0.7)**	(0.9)
Settlement loss	**(5.4)**	—	**—**	—
Fair value of plan assets at December 31,	**128.0**	113.9	**—**	—
Underfunded status (current and long-term)	**$ (7.3)**	$ (21.3)	**$ (2.7)**	$ (2.6)
Amounts recognized in balance sheets				
Accounts payable and accrued expenses	**$ (3.1)**	$ (9.2)	**$ (0.1)**	$ (0.2)
Other long-term liabilities	**(4.2)**	(12.1)	**(2.6)**	(2.4)
Total amount recognized in balance sheet	**$ (7.3)**	$ (21.3)	**$ (2.7)**	$ (2.6)
Amounts recognized in AOCI				
Net actuarial loss (gain)	**$ 15.4**	$ 15.7	**$ 1.0**	$ 0.4
Prior service cost	**—**	—	**—**	—
Total amount recognized in AOCI	**$ 15.4**	$ 15.7	**$ 1.0**	$ 0.4

The following table sets forth the Company's Pension Plan, SERP and Medical Plan cost and amounts recognized in other comprehensive income (before tax) for the respective years ended December 31:

	Pension Plan and SERP benefits			Medical Plan benefits		
	2020	2019	2018	**2020**	2019	2018
Components of net periodic benefit cost	(in millions)					
Service cost	**$ —**	$ 0.3	$ 0.8	**$ —**	$ —	$ —
Interest cost	**4.1**	4.8	4.6	**0.1**	0.1	0.1
Expected return on plan assets	**(6.1)**	(5.9)	(5.8)	**—**	—	—
Curtailment (gain) loss	**—**	2.0	0.3	**—**	(0.8)	(0.2)
Settlement loss	**1.0**	—	—	**—**	—	—
Amortization of prior service costs	**—**	0.4	0.8	**—**	—	(0.3)
Amortization of actuarial loss	**0.9**	0.5	0.8	**—**	—	—
Periodic expense	**$ (0.1)**	$ 2.1	$ 1.5	**$ 0.1**	$ (0.7)	$ (0.4)
Components recognized in accumulated other comprehensive income						
Current period prior service cost	**$ —**	$ —	$ —	**$ —**	$ —	$ 0.2
Current period actuarial (gain) loss	**1.6**	(2.4)	5.6	**0.7**	0.9	(0.1)
Amortization of prior service cost	**—**	(0.4)	(0.8)	**—**	0.8	0.3
Amortization of actuarial gain (loss)	**(0.9)**	(0.5)	(0.8)	**—**	—	—
Loss on curtailment in current period	**—**	(0.8)	(0.1)	**—**	—	—
Settlement loss	**(1.0)**	—	—	**—**	—	—
Total amount recognized in accumulated other comprehensive income	**$ (0.3)**	$ (4.1)	$ 3.9	**$ 0.7**	$ 1.7	$ 0.4

The estimated portion of net actuarial loss cost for the Pension Plan and SERP that will be amortized from AOCI into net periodic benefit cost in 2021 is $1.0 million, which represents amortization of actuarial losses. The estimated portion of net actuarial loss for the Medical Plan that will be amortized from AOCI into net periodic benefit cost in 2021 is less than $0.1 million, which represents amortization of actuarial losses. Amortization of actuarial gains or losses out of AOCI are recognized in the statements of operations in "Interest and other income (expense)".

Following are the weighted-average discount rates (weighted by the plan level benefit obligation for pension benefits) used by the Company to calculate the Pension Plan, SERP and Medical Plan obligations at December 31, 2020 and 2019:

	Pension Plan and SERP benefits		Medical Plan benefits	
	2020	2019	**2020**	2019
Discount rate	**2.45 %**	3.13 %	**2.70 %**	3.40 %

The discount rate assumptions used by the Company represent an estimate of the interest rate at which the Pension Plan, SERP and Medical Plan obligations could effectively be settled on the measurement date.

Following are the weighted-average assumptions (weighted by the net period benefit cost for pension benefits) used by the Company in determining the net periodic Pension Plan, SERP and Medical Plan cost for the years ended December 31:

	Pension Plan and SERP benefits			Medical Plan benefits		
	2020	2019	2018	**2020**	2019	2018
Discount rate	**3.21 %**	4.19 %	3.50 %	**3.40 %**	4.30 %	3.60 %
Expected long-term return on plan assets	**5.70 %**	5.70 %	6.00 %	**n/a**	n/a	n/a
Rate of increase in compensation[(1)]	**n/a**	3.00 %	3.50 %	**n/a**	n/a	n/a

(1) As the Pension Plan was frozen, such that employees do not accrue additional defined benefits for future service or compensation on or after January 1, 2016, rate of increase in compensation for participants is no longer considered an assumption used by the Company to calculate the value of the Pension Plan. As of January 1, 2020, there were no longer any active employees eligible for the SERP. As such, the rate of increase in compensation is only used for the SERP for the years ended December 31, 2019 and 2018.

In selecting the assumption for expected long-term rate of return on assets, the Company considers the average rate of return expected on the funds to be invested to provide benefits. This includes considering the plan's asset allocation, historical returns on these types of assets, the current economic environment and the expected returns likely to be earned over the life of the plan. No plan assets are expected to be returned to the Company in 2021. Historical health care cost trend rates are not applicable to the Company, because the Company's medical costs are capped at a fixed amount. As the Company's medical costs are capped at a fixed amount, the sensitivity to increases and decreases in the health-care inflation rate is not applicable.

Plan Assets
The Company's Employee Benefits Committee (EBC) oversees investment of qualified pension plan assets. The EBC uses a third-party asset manager to assist in setting targeted-policy ranges for the allocation of assets among various investment categories. The EBC allocates pension plan assets among broad asset categories and reviews the asset allocation at least annually. Asset allocation decisions consider risk and return, future-benefit requirements, participant growth and other expected cash flows. These characteristics affect the level, risk and expected growth of postretirement-benefit assets. The EBC uses asset-mix guidelines that include targets for each asset category, return objectives for each asset group and the desired level of diversification and liquidity. These guidelines may change from time to time based on the EBC's ongoing evaluation of each plan's risk tolerance. The EBC estimates an expected overall long-term rate of return on assets by weighting expected returns of each asset class by its targeted asset allocation percentage. Expected return estimates are developed from analysis of past performance and forecasts of long-term return expectations by third-parties. Responsibility for individual security selection rests with each investment manager, who is subject to guidelines specified by the EBC. The EBC sets performance objectives for each investment manager that are expected to be met over a three-year period or a complete market cycle, whichever is shorter. Performance and risk levels are regularly monitored to confirm policy compliance and that results are within expectations. Performance for each investment is measured relative to the appropriate index benchmark for its category. QEP securities may be considered for purchase at an investment manager's discretion, but within limitations prescribed by the Employee Retirement Income Security Act of 1974 (ERISA) and other laws. There was no direct investment in QEP shares for the periods disclosed. The majority of retirement-benefit assets were invested as follows:

Equity securities: Domestic equity assets were invested in a combination of index funds and actively managed products, with a diversification goal representative of the whole U.S. stock market. International equity securities consisted of developed and emerging market foreign equity assets that were invested in funds that hold a diversified portfolio of common stocks of corporations in developed and emerging foreign countries.

Debt securities: Investment grade intermediate-term debt assets are invested in funds holding a diversified portfolio of debt of governments, corporations and mortgage borrowers with average maturities of five to ten years and investment grade credit ratings. Investment grade long-term debt assets are invested in a diversified portfolio of debt of corporate and non-corporate issuers, with an average maturity of more than ten years and investment grade credit ratings. High yield and bank loan assets are held in funds holding a diversified portfolio of these instruments with an average maturity of five to seven years.

Although the actual allocation to cash and short-term investments is minimal (less than 5%), larger cash allocations may be held from time to time if deemed necessary for operational aspects of the retirement plan. Cash is invested in a high-quality, short-term temporary investment fund that purchases investment-grade quality short-term debt issued by governments and corporations.

The EBC made the decision to invest all of the retirement plan assets in commingled funds as these funds typically have lower expense ratios and are more tax efficient than mutual funds. These investments are public investment vehicles valued using the net asset value (NAV) as a practical expedient. The NAV is based on the underlying assets owned by the fund excluding transaction costs and minus liabilities, which can be traced back to observable asset values. No assets held by the Pension Plan that were valued using the NAV methodology were subject to redemption restrictions on their valuation date. These commingled funds are audited annually by an independent accounting firm.

The following table summarizes investments for which fair value is measured using the NAV per share practical expedient as of December 31, 2020 and 2019, respectively:

	December 31, 2020		December 31, 2019	
	Total	**Percentage of total**	Total	Percentage of total
	(in millions, except percentages)			
Cash and short-term investments	**$ 0.6**	**— %**	$ 0.6	1 %
Equity securities:				
Domestic	**23.8**	**19 %**	30.6	27 %
International	**8.5**	**7 %**	10.5	9 %
Fixed income	**95.1**	**74 %**	72.2	63 %
Total investments	**$ 128.0**	**100 %**	$ 113.9	100 %

Expected Benefit Payments
As of December 31, 2020, the following future benefit payments are expected to be paid:

	Pension Plan and SERP benefits	Medical Plan benefits
	(in millions)	
2021	$ 9.0	$ 0.2
2022	$ 9.1	$ 0.2
2023	$ 7.6	$ 0.1
2024	$ 7.5	$ 0.1
2025	$ 6.8	$ 0.1
2026 through 2030	$ 31.4	$ 0.5

Employee Investment Plan
QEP employees may participate in the QEP Employee Investment Plan, a defined-contribution plan (401(k) Plan). The 401(k) Plan allows eligible employees to make investments, including purchasing shares of QEP common stock, through payroll deduction at the current fair market value on the transaction date. Both employees and QEP make contributions to the 401(k) Plan. The Company may contribute a discretionary portion beyond the Company's matching contribution to employees not in the Pension Plan or SERP. During the years ended December 31, 2020, 2019 and 2018, the Company made contributions of $3.0 million, $3.6 million and $5.8 million to the 401(k) Plan, respectively. The Company recognizes expense equal to its yearly contributions. Participants receive 100% employer matching contributions on participant 401(k) plan contributions up to a percentage of qualifying earnings as described below.

	Year Ended December 31,		
	2020	2019	2018
Employees who do not accrue a benefit in the SERP			
Maximum employer matching of qualifying earnings	**8 %**	8 %	8 %
Employees who accrue a benefit in the SERP			
Maximum employer matching of qualifying earnings	**6 %**	6 %	6 %

As a result of freezing benefits under the Pension Plan, the 401(k) Plan and the Wrap Plan were amended to allow the Company to make discretionary contributions in the form of Company Transition Credits to eligible participants. Eligible participants are certain highly and non-highly compensated employees who were active participants in the Pension Plan on December 31, 2015. During the years ended December 31, 2020 and 2019, the Company made a discretionary contribution of less than $0.1 million to active participants of the Pension Plan. During the year ended December 31, 2018, the Company made a discretionary contribution of $0.3 million to active participants of the Pension Plan.

Nonqualified, Unfunded Deferred Compensation Wrap Plan
QEP offers a nonqualified, unfunded deferred compensation wrap plan to certain individuals. The Wrap Plan provides participants with certain tax planning benefits as well as supplemental funds for retirement and allows participants to defer the receipt of various types of compensation. Participants are able to select from a variety of investment options, including mutual funds and phantom QEP shares. As of December 31, 2020 and 2019, the Wrap Plan obligations for participants' future benefits were $25.5 million and $26.8 million, respectively, and are included in "Other long-term liabilities" on the balance sheets. The Company established a Rabbi Trust to hold the investments associated with the Wrap Plan (other than phantom QEP shares) and to pay Wrap Plan obligations as they arise. As of December 31, 2020 and 2019, the marketable securities held in the Rabbi Trust were $23.4 million and $23.1 million, respectively, and are included in "Other noncurrent assets" on the balance sheets.

Changes in the fair value of Wrap Plan obligations and marketable securities are recorded as "Deferred compensation mark-to-market adjustments" and "Unrealized gain/loss on marketable securities" within "General and administrative" and "Interest and other income (expense)", respectively, on the statements of operations. "Deferred compensation mark-to-market adjustments" and "Unrealized gain/loss on marketable securities" for the years ended December 31, 2020, 2019 and 2018, respectively, are summarized in the table below:

	Year Ended December 31, (in millions)		
	2020	2019	2018
Deferred compensation mark-to-market adjustments	$ 1.0	$ 2.3	$ (3.9)
Unrealized (gain)/loss on marketable securities	(3.2)	(3.9)	1.2

Refer to Note 5 – Fair Value Measurements for more information on the fair value measurement of the marketable securities held in the Rabbi Trust and the Wrap Plan obligations.

Note 13 – Income Taxes

The Tax Cuts and Jobs Act enacted in December 2017 changed several aspects of corporate taxation, including decreasing our federal corporate statutory tax rate from 35% to 21%, limiting the amount of interest the Company could potentially deduct and eliminating the corporate AMT. The elimination of the corporate AMT allowed the Company to claim AMT refunds for AMT credits carried forward from prior tax years. The CARES Act enacted in March 2020 permitted the Company to carry back its NOL generated in 2018 and 2019, creating additional AMT credits, and to accelerate all of its AMT refunds. Guidance issued by the relevant regulatory authorities regarding tax legislation may materially impact QEP's financial statements. As additional guidance to the Tax Cuts and Jobs Act and the CARES Act is published in the form of Treasury Regulations and other IRS communications, the Company will monitor, assess and determine the impact of these communications on the Company's consolidated financial statements and statements of operations.

Details of income tax provisions and deferred income taxes from continuing operations are provided in the following tables.

The components of income tax provisions and benefits were as follows:

	Year Ended December 31,		
	2020	2019	2018
Federal income tax provision (benefit)	(in millions)		
Current	**$ (189.5)**	$ (32.2)	$ (71.3)
Deferred	**116.0**	55.7	(257.8)
State income tax provision (benefit)			
Current	**(1.0)**	(15.1)	1.5
Deferred	**(5.4)**	(51.4)	10.2
Total income tax provision (benefit)	**$ (79.9)**	$ (43.0)	$ (317.4)

The difference between the statutory federal income tax rate and the Company's effective income tax rate is explained as follows:

	Year Ended December 31,		
	2020	2019	2018
Federal income taxes statutory rate	**21.0 %**	21.0 %	21.0 %
Increase (decrease) in rate as a result of:			
State income taxes, net of federal income tax benefit	**(1.6)%**	(2.5)%	4.1 %
State rate change[1]	**8.0 %**	20.9 %	(2.9)%
Valuation allowance[2]	**3.3 %**	(18.0)%	(1.9)%
Permanent adjustments[3]	**(7.2)%**	(7.1)%	(0.1)%
Return to provision adjustment	**1.1 %**	2.7 %	(0.1)%
Uncertain tax provision[4]	**— %**	13.6 %	— %
NOL rate re-measurements[5]	**79.6 %**	— %	3.8 %
Effective income tax rate	**104.2 %**	30.6 %	23.9 %

(1) During the year ended December 31, 2020, the state rate change was primarily the result of the re-measurement of QEP's deferred tax assets and liabilities at a lower blended state rate due to the changing apportionment of the Company's revenues and property in its remaining operating areas. During the year ended December 31, 2019, the state rate change was primarily the result of the re-measurement of QEP's deferred tax assets and liabilities at a lower blended state tax rate due to exiting the state of Louisiana.

(2) During the year ended December 31, 2019, the Company recognized an additional valuation allowance of $25.3 million on its Louisiana state NOL. The Company did not expect that it would have sufficient taxable income to utilize the state NOL it is carrying forward due to the Haynesville Divestiture. During the year ended December 31, 2018, the Company also increased its valuation allowance by $25.5 million against its Louisiana net operating loss as the Company did not forecast sufficient taxable income to utilize the entire net operating loss in Louisiana at December 31, 2018.

(3) During the years ended December 31, 2020, and 2019, the permanent items primarily related to disallowed officer compensation under Section 162(m) of the Internal Revenue Code of $1.9 million and $6.1 million and share-based compensation shortfalls of $3.6 million and $4.0 million, respectively.

(4) During the year ended December 31, 2019, the Company recognized a tax benefit of $19.0 million due to the expiration of the statute of limitations related to the Company's uncertain tax position.

(5) During the year ended December 31, 2020, QEP had a remeasurement of deferred taxes due to NOL carrybacks under the CARES Act to a year with a higher federal tax rate. This remeasurement provided a tax benefit of $61.0 million during the year ended December 31, 2020. During the year ended December 31, 2018, QEP agreed to an IRS proposed change to the initial treatment of the 2016 carryback of NOL. This change resulted in a reduction of available NOL carryforwards valued at $75.7 million and an increase in AMT credit carryforwards of $126.0 million. The net change in value of $50.3 million was recorded in deferred income taxes.

Significant components of the Company's deferred income taxes were as follows:

	December 31,			
	2020		2019	
Deferred tax liabilities	(in millions)			
Property, plant and equipment	$	**627.5**	$	592.9
Operating lease right-of-use assets		**10.7**		12.7
Other		**2.4**		0.9
Total deferred tax liabilities		**640.6**		606.5
Deferred tax assets				
NOL and tax credit carryforwards	$	**306.2**	$	337.7
State NOL valuation allowance		**(101.9)**		(98.8)
Employee benefits and compensation costs		**15.9**		22.3
Interest carryforward [(1)]		**—**		45.7
Commodity price derivatives		**17.0**		3.9
Operating lease liabilities		**11.7**		14.1
Other		**6.5**		7.1
Total deferred tax assets		**255.4**		332.0
Net deferred income tax liability	**$**	**385.2**	$	274.5
Balance sheet classification				
Deferred income tax liability – noncurrent		**385.2**		274.5
Net deferred income tax liability	**$**	**385.2**	$	274.5

(1) The decrease in the interest expense carry forward is due to the issuance of final regulations by the U.S. Department of Treasury in July 2020 that relate to the deductibility of interest expense. After the application of these regulations the Company expects to fully deduct all of its remaining interest that was carried forward at December 31, 2019.

As of December 31, 2020, the Company had a gross U.S. NOL of $863.5 million and various gross state NOL's of $5,059.8 million. The tax effected amounts and expiration dates of NOL and tax credit carryforwards at December 31, 2020, are as follows:

	Expiration Dates	Amounts	
		(in millions)	
State NOL and tax credit carryforwards	2021-Indefinite	**$**	**121.1**
U.S. NOL[(1)]	2037-Indefinite		**181.3**
General business credits	2036-2037		**3.8**
Total NOL and tax credit carryforwards		**$**	**306.2**

(1) Federal NOLs created in tax years beginning after December 31, 2017 can be carried forward indefinitely under the Tax Cuts and Jobs Act (limited to 80% of taxable income computed without the NOL deduction). Of the Company's U.S. NOL, $18.7 million has an indefinite carryforward period but its use is limited to 80% of taxable income.

The Company assesses the available positive and negative evidence to determine if sufficient future taxable income will be generated to use the existing deferred tax assets. The Company maintains a valuation allowance to offset the uncertain realization of certain of its state NOL's on the basis that they are not more likely than not to be realized. The Company had a valuation allowance of $101.9 million and $98.8 million as of December 31, 2020 and 2019, respectively, for state NOL's outside of our current core operations and primarily relate to state NOL's in Colorado, Louisiana, Utah and Oklahoma. Due to the various divestitures over the last several years, and focus of our operations, we do not expect to have sufficient taxable income in these states to utilize the NOL's we are carrying forward.

The Tax Cuts and Jobs Act eliminated corporate AMT which allowed QEP the ability to offset its regular tax liability or claim refunds for taxable years 2018 through 2021 for AMT credits carried forward from prior years. The CARES Act permitted the Company to carry back its NOL generated in 2018 and 2019, creating additional AMT credits, and to accelerate all of its AMT refunds. The Company received $170.7 million, including interest income, and $73.9 million of AMT credit refunds in 2020 and 2019, respectively, and anticipates it will realize approximately $61.6 million in AMT credit refunds, with $30.7 million expected to be realized within the next 12 months, which is shown in "Income tax receivable" with the remaining $30.9 million included in "Other noncurrent assets" on the balance sheets as of December 31, 2020.

Pursuant to Section 382 and 383 of the Internal Revenue Code, utilization of the Company’s NOL's and credits may be subject to annual limitations in the event of any significant future changes in its ownership structure. These annual limitations may result in the expiration of NOL's and credits prior to utilization.

The Company files income tax returns in the U.S. federal jurisdiction and various state jurisdictions. For federal tax purposes, the Company has been a participant in the IRS Compliance Assurance Process through the 2019 tax year, which provides examination of the tax return either prior to or post filing. Generally, for state tax purposes, the Company’s 2017 through 2019 tax years remain open for examination by the taxing authorities under a three-year statute of limitations. Should the Company utilize any of its state loss carryforwards, their carryforward losses would be subject to examination.

Unrecognized Tax Benefit
The benefits of uncertain tax positions taken or expected to be taken on income tax returns is recognized in the Consolidated Financial Statements at the largest amount that is more likely than not to be sustained upon examination by the relevant taxing authorities.

During the year ended December 31, 2019, the statute of limitations related to the Company's uncertain tax position expired, and upon expiration, the Company recognized a $19.0 million tax benefit and recorded a $4.1 million reduction in "Interest expense" and a $2.5 million reduction in "General and administrative" expense on the statements of operations related to accrued interest and penalties that were recorded in prior periods. During the year ended December 31, 2018 the Company incurred $0.7 million of estimated interest expense related to uncertain tax positions.

The following is a reconciliation of our beginning and ending amounts of unrecognized tax benefits for the years ended December 31, 2020 and 2019:

	Unrecognized Tax Benefits	
	2020	2019
	(in millions)	
Balance as of January 1,	$ —	$ 19.0
Recognized tax benefits	—	(19.0)
Balance as of December 31,	**$ —**	$ —

Note 14 – Quarterly Financial Information (unaudited)

The following table provides a summary of unaudited quarterly financial information:

2020	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(in millions, except per share amounts or otherwise specified)				
Revenues	**$ 225.8**	**$ 120.6**	**$ 177.8**	**$ 200.2**	**$ 724.4**
Operating income (loss)	**$ (7.2)**	**$ (112.5)**	**$ (42.1)**	**$ (61.9)**	**$ (223.7)**
Net income (loss)	**$ 367.4**	**$ (184.4)**	**$ (49.2)**	**$ (130.6)**	**$ 3.2**
Net gain (loss) from asset sales, inclusive of restructuring costs and impairment	**$ 3.7**	**$ —**	**$ 0.1**	**$ (11.3)**	**$ (7.5)**
Per share information					
Basic EPS	**$ 1.54**	**$ (0.76)**	**$ (0.20)**	**$ (0.54)**	**$ 0.01**
Diluted EPS	**$ 1.54**	**$ (0.76)**	**$ (0.20)**	**$ (0.54)**	**$ 0.01**
Production information					
Total equivalent production (Mboe)	**7,930.9**	**7,972.9**	**7,057.0**	**7,364.1**	**30,324.9**

2019	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Revenues	$ 280.6	$ 296.2	$ 307.5	$ 321.9	$ 1,206.2
Operating income (loss)	$ (15.8)	$ 72.3	$ 52.1	$ 48.9	$ 157.5
Net income (loss)	$ (116.7)	$ 48.8	$ 81.0	$ (110.4)	$ (97.3)
Net gain (loss) from asset sales, inclusive of restructuring costs and impairment	$ (18.2)	$ 17.8	$ (2.1)	$ 1.4	$ (1.1)
Per share information					
Basic EPS	$ (0.49)	$ 0.20	$ 0.34	$ (0.46)	$ (0.41)
Diluted EPS	$ (0.49)	$ 0.20	$ 0.34	$ (0.46)	$ (0.41)
Production information					
Total equivalent production (Mboe)	7,806.3	7,534.7	8,404.0	8,465.3	32,210.3

Note 15 – Supplemental Oil and Gas Information (unaudited)

The Company is making the following supplemental disclosures of oil and gas producing activities, in accordance with ASC 932, *Extractive Activities – Oil and Gas*, as amended by ASU 2010-03, *Oil and Gas Reserve Estimation and Disclosures*, and SEC Regulation S-X. The Company uses the successful efforts accounting method for its oil and gas exploration and development activities.

Capitalized Costs

The aggregate amounts of costs capitalized for oil and gas exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below:

	December 31,	
	2020	2019
	(in millions)	
Proved properties	**$ 9,941.2**	$ 9,574.9
Unproved properties, net	**454.4**	599.1
Total proved and unproved properties	**10,395.6**	10,174.0
Accumulated depreciation, depletion and amortization	**(5,728.0)**	(5,250.5)
Net capitalized costs	**$ 4,667.6**	$ 4,923.5

Costs Incurred
The costs incurred in oil and gas acquisition, exploration and development activities are displayed in the table below. Costs associated with the Company's midstream and corporate activities are not included. Development costs are net of the change in accrued capital costs of $26.2 million and ARO additions and revisions of $1.2 million during the year ended December 31, 2020. The costs incurred for the development of reserves that were classified as proved undeveloped were approximately $222.3 million in 2020, $426.1 million in 2019 and $606.5 million in 2018.

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Proved property acquisitions	**$ 2.9**	$ 1.5	$ 39.1
Unproved property acquisitions	**1.2**	2.0	25.8
Other acquisitions	**—**	—	0.8
Exploration costs (capitalized and expensed)	**0.2**	0.1	0.3
Development costs	**324.8**	556.2	1,133.1
Total costs incurred	**$ 329.1**	$ 559.8	$ 1,199.1

Results of Operations
Following are the results of operations of QEP's oil and gas producing activities, before allocated corporate overhead and interest expenses. Revenues and expenses relating to the Company's midstream and corporate activities are not included.

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Revenues	**$ 721.0**	$ 1,200.6	$ 1,920.3
Production costs	**292.9**	361.9	507.3
Exploration expenses	**0.2**	0.1	0.3
Depreciation, depletion and amortization	**564.2**	528.5	836.4
Impairment	**8.7**	—	1,560.9
Gathering and other expense	**(0.2)**	—	—
Total expenses	**865.8**	890.5	2,904.9
Income (loss) before income taxes	**(144.8)**	310.1	(984.6)
Income tax benefit (expense)	**32.1**	(69.5)	243.2
Results of operations from producing activities excluding allocated corporate overhead and interest expenses	**$ (112.7)**	$ 240.6	$ (741.4)

Estimated Quantities of Proved Oil and Gas Reserves
Estimates of proved oil and gas reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which include the oversight of a multi-functional Reserves Review Committee reporting to the Company's Audit Committee of the Board of Directors. The Company retained Ryder Scott Company, L.P. (RSC), independent oil and gas reserve evaluation engineering consultants, to prepare the estimates of all of its proved reserves as of December 31, 2020, 2019 and 2018. The estimated proved reserves have been prepared in accordance with the SEC's Regulation S-X and ASC 932 as amended. The individuals performing reserves estimates possess professional qualifications and demonstrate competency in reserves estimation and evaluation. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors.

All of QEP's proved undeveloped reserves at December 31, 2020, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. The Company plans to continue development of its leaseholds and anticipates that it will have the financial capability to continue development in the manner estimated. While the majority of QEP's PUD reserves are located on leaseholds that are held by production, any PUD locations on expiring leaseholds are scheduled for development during the primary term of the lease.

As of December 31, 2020, all of the Company's oil and gas reserves are attributable to properties within the United Sates. A summary of the Company's changes in quantities of proved oil and condensate, gas and NGL reserves for the years ended December 31, 2018, 2019 and 2020 are as follows:

	Oil and condensate	Gas	NGL	Total[10]
	(MMbbl)	(Bcf)	(MMbbl)	(MMboe)
Balance at December 31, 2017	320.5	1,793.6	65.2	684.7
Revisions of previous estimates[1]	2.1	314.0	6.7	61.0
Extensions and discoveries[2]	57.1	56.5	9.8	76.3
Purchase of reserves in place[3]	8.2	7.9	1.3	10.9
Sale of reserves in place[4]	(24.9)	(544.8)	(7.1)	(122.8)
Production	(23.9)	(139.6)	(4.7)	(51.9)
Balance at December 31, 2018	339.1	1,487.6	71.2	658.2
Revisions of previous estimates[5]	(94.9)	(23.0)	(8.7)	(107.3)
Extensions and discoveries[6]	33.6	40.0	7.4	47.6
Purchase of reserves in place[7]	3.6	4.0	0.7	4.9
Sale of reserves in place[8]	(4.9)	(1,102.2)	(0.3)	(188.9)
Production	(21.6)	(33.1)	(5.1)	(32.2)
Balance at December 31, 2019	254.9	373.3	65.2	382.3
Revisions of previous estimates[9]	**2.7**	**27.6**	**4.1**	**11.4**
Extensions and discoveries	**0.1**	**0.2**	**—**	**0.2**
Sale of reserves in place	**(0.1)**	**(0.3)**	**—**	**(0.2)**
Production	**(19.7)**	**(32.5)**	**(5.2)**	**(30.3)**
Balance at December 31, 2020	**237.9**	**368.3**	**64.1**	**363.4**
Proved developed reserves				
Balance at December 31, 2017	116.0	655.5	27.9	253.1
Balance at December 31, 2018	133.6	382.3	31.5	228.9
Balance at December 31, 2019	117.5	217.0	36.7	190.4
Balance at December 31, 2020	**101.2**	**185.0**	**32.0**	**164.0**
Proved undeveloped reserves				
Balance at December 31, 2017	204.5	1,138.1	37.3	431.6
Balance at December 31, 2018	205.5	1,105.3	39.7	429.3
Balance at December 31, 2019	137.4	156.3	28.5	191.9
Balance at December 31, 2020	**136.7**	**183.3**	**32.1**	**199.4**

(1) Revisions of previous estimates in 2018 totaling 61.0 MMboe of positive revisions include 23.4 MMboe of other revisions, primarily related to changing our development plans in the Haynesville/Cotton Valley; 17.3 MMboe of positive revisions related to pricing, primarily driven by higher oil prices; 11.7 MMboe of positive revisions related to lower operating costs; and 8.7 MMboe of positive performance revisions.

(2) Extensions and discoveries in 2018 primarily related to new well completions and associated new PUD locations in the Permian Basin.

(3) Purchase of reserves in place in 2018 primarily relates to the additional acquisitions in the Permian Basin as discussed in Note 3 – Acquisitions and Divestitures.

(4) Sale of reserves in place in 2018 was primarily related to QEP's Uinta Basin Divestiture as discussed in Note 3 – Acquisitions and Divestitures.

(5) Revisions of previous estimates in 2019 totaling 107.3 MMboe of negative revisions includes 44.5 MMboe of negative PUD revisions as a result of changes to the development sequence in the Permian Basin, to maximize capital efficiency (see offset in extensions and discoveries footnote 6 below); 25.8 MMboe of PUD removals, primarily in the Williston Basin, that will not be developed within five years of the initial date of booking due to the reduction in future capital expenditures; 17.0 MMboe of negative revisions related to pricing, primarily driven by lower oil prices; 13.7 MMboe of negative performance revisions, primarily associated with updated volume projections for high-density wells and certain undrilled locations in the Permian Basin; 10.9 MMboe of other negative revisions, partially offset by 4.6 MMboe of positive revisions related to lower operating costs.

(6) Extensions and discoveries in 2019 primarily related to new PUD locations in the Permian Basin due to changes in the development sequence in the Permian Basin to maximize capital efficiency. See partial offset in revisions to previous estimates in footnote 9 above.

(7) Purchase of reserves in place in 2019 primarily relates to the additional acquisitions in the Permian Basin as discussed in Note 3 – Acquisitions and Divestitures.

(8) Sale of reserves in place in 2019 was primarily related to QEP's Haynesville Divestiture as discussed in Note 3 – Acquisitions and Divestitures.

(9) Revisions of previous estimates in 2020 totaling 11.4 MMboe of positive revisions includes 63.0 MMboe of positive revisions, of which 58.8 MMboe was positive PUD revisions, as a result of changes in development sequence in the Permian Basin to maximize Free Cash Flow. Additionally, there were 4.2 MMboe of positive revisions related to lower operating costs and 2.5 MMboe of other positive revisions, partially offset by 41.4 MMboe of negative price revisions, primarily driven by lower oil prices and 16.9 MMboe of PUD removals, primarily in Permian Basin, that will not be developed within five years of the initial date of booking due to the reduction in future capital expenditures.

(10) Generally, gas consumed in operations was excluded from reserves, however, in some cases, produced gas consumed in operations was included in reserves when the volumes replaced fuel purchases.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31, 2020, 2019 and 2018, by applying prices, which were the simple average of the first-of-the-month commodity prices, adjusted for location and quality differentials, for each of the 12 months during 2020, 2019 and 2018, with consideration of known contractual price changes. The prices used do not include any impact of QEP's commodity derivatives portfolio. The following table provides the average benchmark prices per unit, before location and quality differential adjustments, used to calculate the related reserve category:

	For the year ended December 31,		
	2020	2019	2018
Average benchmark price per unit:			
Oil price (per bbl)	**$ 39.57**	$ 55.51	$ 65.56
Gas price (per MMbtu)	**$ 1.99**	$ 2.58	$ 3.10

Year ended operating expenses, development costs and appropriate statutory income tax rates, with consideration of future tax rates, were used to compute the future net cash flows. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop proved undeveloped reserves are approximately $202.6 million in 2021, $289.1 million in 2022 and $365.8 million in 2023. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. QEP believes cash flow from its operating activities, cash on hand and borrowings under its revolving credit facility will be sufficient to cover these estimated future development costs.

The assumptions used to derive the standardized measure of discounted future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The information may be useful for certain comparative purposes but should not be solely relied upon in evaluating QEP or its performance. Furthermore, information contained in the following table may not represent realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's reserves. Management believes that the following factors should be considered when reviewing the information below:

- Future commodity prices received for selling the Company's net production will likely differ from those required to be used in these calculations.
- Future operating and capital costs will likely differ from those required to be used in these calculations and do not reflect cost savings of Company owned midstream operations on future operating expenses.
- Future market conditions, government regulations, reservoir conditions and risks inherent in the production of oil and condensate and gas may cause production rates in future years to vary significantly from those rates used in the calculations.
- Future revenues may be subject to different production, severance and property taxation rates.
- The selection of a 10% discount rate is arbitrary and may not be a reasonable factor in adjusting for future economic conditions or in considering the risk that is part of realizing future net cash flows from the reserves.

The standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Future cash inflows	**$ 9,657.0**	$ 14,447.6	$ 26,482.6
Future production costs	**(4,728.9)**	(6,070.6)	(9,539.9)
Future development costs[1]	**(1,671.0)**	(2,275.2)	(4,441.5)
Future income tax expenses[2]	**(294.8)**	(845.8)	(2,553.6)
Future net cash flows	**2,962.3**	5,256.0	9,947.6
10% annual discount for estimated timing of net cash flows	**(1,427.0)**	(2,579.7)	(4,991.9)
Standardized measure of discounted future net cash flows	**$ 1,535.3**	$ 2,676.3	$ 4,955.7

(1) Future development costs include future abandonment and salvage costs.

(2) The standardized measure of discounted future net cash flows for the year ended December 31, 2020, 2019 and 2018, were estimated assuming a 21% federal tax rate from the Tax Cuts and Jobs Act enacted in December 2017.

The principal sources of change in the standardized measure of discounted future net cash flows relating to proved reserves is presented in the table below:

	Year Ended December 31,		
	2020	2019	2018
		(in millions)	
Balance at January 1,	**$ 2,676.3**	$ 4,955.7	$ 3,097.3
Sales of oil and condensate, gas and NGL produced, net of production costs	**(428.1)**	(838.7)	(1,413.0)
Net change in sales prices and in production (lifting) costs related to future production	**(2,136.4)**	(1,988.6)	1,632.5
Net change due to extensions and discoveries	**2.4**	220.9	692.6
Net change due to revisions of quantity estimates	**159.6**	(2,079.2)	732.0
Net change due to purchases of reserves in place	**—**	34.2	117.0
Net change due to sales of reserves in place	**(1.9)**	(617.8)	(369.6)
Previously estimated development costs incurred during the period	**256.1**	460.8	735.6
Changes in estimated future development costs	**418.7**	1,064.7	(28.3)
Accretion of discount	**310.7**	622.8	375.4
Net change in income taxes	**277.9**	841.5	(615.7)
Other	**—**	—	(0.1)
Net change	**(1,141.0)**	(2,279.4)	1,858.4
Balance at December 31,	**$ 1,535.3**	$ 2,676.3	$ 4,955.7

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(b) under the Securities Exchange Act of 1934, as amended), as of December 31, 2020. Based on such evaluation, such officers have concluded that, as of December 31, 2020, the Company's disclosure controls and procedures are designed and effective to ensure that information required to be included in the Company's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms and that information required to be disclosed in the Company's reports filed or submitted under the Exchange Act is accumulated and communicated to the Company's management including its principal executive officer and principal financial officer, or persons performing similar functions, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating the Company's disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the control system will be met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events and the application of judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of these and other inherent limitations of control systems, there is only reasonable assurance that the Company's controls will succeed in achieving their goals under all potential future conditions.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting (as defined by Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2020, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Assessment of Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rules 13a-15(f) and 15d-15(f). The Company's internal control over financial reporting is a process designed under the supervision of QEP's chief executive officer and chief financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with accounting principles generally accepted. Because of its inherent limitations, internal control over financial reporting may not detect or prevent misstatements. Also, projections of any evaluation of the 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 processes may deteriorate.

As of December 31, 2020, management assessed the effectiveness of our internal control over financial reporting based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission for effective internal control over financial reporting. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting as of December 31, 2020. Management included in its assessment of internal control over financial reporting all consolidated entities.

Deloitte & Touche LLP, an independent registered public accounting firm that audited the Consolidated Financial Statements included in this Annual Report on Form 10-K, has issued an attestation report, included immediately following, on the effectiveness of our internal control over financial reporting as of December 31, 2020.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of QEP Resources, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of QEP Resources, Inc. and subsidiaries (the "Company") as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2020, of the Company and our report dated February 24, 2021, expressed an unqualified opinion on those consolidated financial statements.

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 Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/ Deloitte & Touche LLP
Denver, Colorado
February 24, 2021

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information about our Directors

Mr. Phillips S. Baker, Jr., age 61, has served as a QEP director since June 2010. He served as a director of Questar from 2004 to 2010. Mr. Baker is the President, CEO and a director of Hecla Mining Company (Hecla), a gold and silver mining company. He served as Chief Financial Officer (CFO) of Hecla from May 2001 to June 2003, and as Chief Operating Officer of Hecla from November 2001 to May 2003, before being named CEO in May 2003. He has over 30 years of business experience, including 19 years of financial management, more than ten years as CEO of an NYSE-listed company and more than 20 years of directorships of public companies. Mr. Baker has also served as Chairman of the Board for the National Mining Association since October 2017, and has been a Board member since 2010. He has also served as a Board member of the National Mining Hall of Fame and Museum.

In concluding that Mr. Baker is qualified to serve as a director, the Board considered, among other things, his financial knowledge and his extensive executive management and financial experience.

Mr. Timothy J. Cutt, age 60, is the President and Chief Executive Officer of QEP and has served as a director of QEP since January 15, 2019. Prior to joining QEP, Mr. Cutt was the Chief Executive Officer of Cobalt International Energy, a development-stage petroleum exploration and production company (2016 to 2018). Cobalt International voluntarily filed a petition for relief under Chapter 11 of the United States Bankruptcy Code on December 14, 2017, and a plan to sell all the assets of the company was approved on April 10, 2018. Prior to joining Cobalt International, Mr. Cutt served as President of the Petroleum Division of BHP Billiton, a global natural resources company (2013 to 2016), and prior to that he also served as President of Production for BHP Billiton's Petroleum Division (2007 to 2011). Prior to joining BHP Billiton, Mr. Cutt served in various roles at ExxonMobil in the prior 25 years, including President of ExxonMobil de Venezuela (2005 to 2007), President ExxonMobil Canada Energy (2004 to 2005), President Hibernia Management & Development Company (2001 to 2004) and Regional Coordinator, North America. He also served as a Board member of the American Petroleum Institute from 2013 to 2018.

In concluding that Mr. Cutt is qualified to serve as a director, the Board considered, among other things, his 35 years of experience in the oil and gas industry.

Ms. Julie A. Dill, age 61, has served as a QEP director since May 2013 and also currently serves as a director of Rayonier Advanced Materials Inc., Inter Pipeline Ltd. and Southern Star Central Gas Pipeline (a private company). Ms. Dill recently served as the Chief Communications Officer for Spectra Energy Corp. (Spectra) from 2013 until completion of Spectra's merger with Enbridge, Inc. in the first quarter of 2017. She also served on the board of Spectra Energy Partners from 2012 until the completion of the merger with Enbridge, Inc. Ms. Dill has a wealth of experience in the energy sector, having served in a number of executive capacities in the natural gas and power industries. She served as the Group Vice President of Strategy for Spectra and the President and CEO of Spectra Energy Partners, LP from 2012 until 2013, and prior to that she served as President of Union Gas Limited from 2007 until 2011. Previously, she served in various financial and operational roles with Duke Energy, Duke Energy International and Shell Oil Company. Ms. Dill also serves on an advisory board for Centuri Construction (a privately-held company), a subsidiary of Southwest Gas Holdings. She is also a member of the Advisory Council for the College of Business and Economics at New Mexico State University and also serves on the Memorial Hermann Hospital Community Relations Committee.

In concluding that Ms. Dill is qualified to serve as a director, the Board considered, among other things, her experience as the President and CEO of a public company, her strong financial background and her more than 35 years of experience in the energy industry.

Mr. Joseph N. Jaggers, age 67, has served as a QEP director since October 2019. Mr. Jaggers' energy industry leadership experience spans more than three decades. From 2013 to 2018, he was President, CEO, Chairman and Founder of Jagged Peak Energy in Denver, Colorado. From 2010 to 2012, he was President, CEO and Director of privately-held Ute Energy, LLC in Denver, Colorado. From 2001 to 2010 he held executive leadership roles with Bill Barrett Corp., Barrett Resources and Williams Companies in Denver. From 1981 to 2000, Mr. Jaggers worked for BP Amoco where he held a variety of staff and management positions, culminating in executive responsibility for BP's Northern North Sea operation. He is a graduate of the United States Military Academy at West Point. He currently serves as a director and member of the Audit and Compensation committees for National Fuel Gas Company. Mr. Jaggers is a past President of the Colorado Oil and Gas Association, Past Executive Director of Independent Producers Association of the Mountain States, a member of the Society of Petroleum Engineers and he has been inducted into the Rocky Mountain Oil and Gas Hall of Fame.

In concluding that Mr. Jaggers is qualified to be nominated to our Board, the Board considered, among other things, his experience as the CEO of a publicly-traded independent exploration and production company and his substantial operational and financial expertise in the oil and gas industry.

Mr. Michael J. Minarovic, age 56, has served as a QEP director since May 2017. Mr. Minarovic is the CEO, Co-Founder and Managing Director of Arena Energy, LP, an employee-owned exploration and production company. Arena Energy, LP voluntarily filed a petition for relief under Chapter 11 of the United States Bankruptcy Code on August 20, 2020, and a plan to sell all the assets of Arena Energy, LP was approved on September 25, 2020. Mr. Minarovic is also the Managing Director and Co-Founder of Arena Offshore, LP, an affiliated drilling and operating company. Mr. Minarovic is the co-founder of White Fleet Drilling, and is the founder of Rosefield Pipeline. Previously, Mr. Minarovic served as a petroleum engineer with Newfield Exploration Company from 1993 to 1999 and Conoco, Inc. from 1988 to 1993. Mr. Minarovic is an executive director of the United States Oil and Gas Association, is a member of the John Cooper School Board of Trustees and is an active member of the Society of Petroleum Engineers. Mr. Minarovic graduated from the University of Texas at Austin, in 1987, with a bachelor's degree in petroleum engineering.

In concluding that Mr. Minarovic is qualified to be nominated to our Board, the Board considered, among other things, his more than 30 years of oil and gas experience working in the independent, private and public sectors, including his entrepreneurial, executive and operational expertise, as well as his background in negotiating and managing acquisitions and joint ventures with large public companies.

Ms. Mary Shafer-Malicki, age 60, has served as a QEP director since July 2017 and currently serves as a director of Wood plc. Ms. Shafer-Malicki retired in 2009 after a 26-year career with BP Exploration Operating Company (BP) and Amoco Corporation. She served as Senior Vice President/CEO and Chief Operating Officer/General Manager for BP's operations in Angola from 2005 to 2009 and Director General for BP's operations in Vietnam from 2003 to 2005. Prior to this, she served as the Business Unit Leader for BP's Central North Sea gas business in Scotland from 2001 to 2003, General Manager for support services to all of BP's Continental Shelf upstream operations in the United Kingdom from 2000 to 2001 and President and General Manager for Amoco/BP's Dutch onshore and offshore production and gas storage operations in the Netherlands from 1998 to 2000. Ms. Shafer-Malicki currently serves as a director of the University of Wyoming Foundation, as well as a member of industry advisory boards for the Chemical Engineering departments at the University of Wyoming and Oklahoma State University. Ms. Shafer-Malicki previously served as a director for McDermott International, Inc. until June 30, 2020.

In concluding that Ms.Shafer-Malicki is qualified to serve as a director, the Board considered, among other things, her extensive energy industry experience, including her serving in senior executive positions, and her experience as a director on multiple public company boards. Ms. Shafer-Malicki was appointed as a director by the Board in July 2017 as part of the Board's succession-planning process and was recommended as a director candidate by the Company's current Board Chair, who was serving as Lead Director at the time.

Mr. Barth E. Whitham, age 64, has served as a QEP director since October 2019. Mr. Whitham is currently the President and CEO of Enduring Resources, LLC, co-founded in 2004 for the acquisition and development of energy resources and infrastructure in North America. He was the co-founding officer of Westport Resources Corporation and President and COO from 1991 to 2004 through its merger with Kerr-McGee. Prior to Westport, Mr. Whitham worked extensively in the upstream U.S., international and offshore energy industry in project planning, development and operations. Mr. Whitham is a graduate of the Colorado School of Mines. He serves on the boards of Ensign Energy Services Inc., Intrepid Potash Corp, Jonah Energy (a privately-held company), Children's Hospital Colorado and is a Trustee of Regis University. Mr. Whitham has served on the Board of SPE International, Western Energy Alliance, CSM Board of Governors and Colorado Forum.

In concluding that Mr. Whitham is qualified to be nominated to our Board, the Board considered, among other things, his public company executive experience in the oil and gas industry and his substantial operational and financial expertise.

Information about our Named Executive Offers

The biographical information for the Company’s named executive officers is contained in Items 1 and 2 of Part I of this Annual Report on Form 10-K.

General Governance Information

We seek to implement best practices in corporate governance, including a robust Code of Conduct, Corporate Governance Guidelines and Board Committee charters (Audit Committee, Compensation Committee and Governance and Social Responsibility Committee), each of which is available on the Company's website at http://ir.qepres.com/corporate-governance/governance-highlights. These documents provide the framework for our corporate governance. Any of these documents will be furnished in print without charge to any interested party who requests them.

Our Code of Conduct applies to all of our directors, officers (including our chief executive officer and chief financial officer) and employees. Any waiver of the Code of Conduct for executive officers must be approved by our Board of Directors. We will post on our website any amendments to or waivers of the Code of Conduct that apply to executive officers.

Audit Committee

The Audit Committee reviews auditing, accounting, financial reporting and internal control functions, and oversees risk assessment and compliance activities. The Audit Committee has the sole authority to hire, compensate, retain, oversee and terminate the Company's independent registered public accounting firm. The Audit Committee also has the sole authority to pre-approve all terms and fees for audit services, audit-related services and other services to be performed by the Company's independent registered public accounting firm. The Audit Committee also reviews any related-person transactions brought to its attention that could reasonably be expected to have a material impact on the Company's financial statements and determines whether any action is necessary.

The Audit Committee meets all the requirements set forth in Sections 303A.06 and 303A.07 of the NYSE Listed Company Manual. The members of the Audit Committee include Julie A. Dill (Chair), Joseph N. Jaggers, Michael J. Minarovic, and Barth E. Whitham. The Board has determined that all members of the Audit Committee satisfy the standards for independence as they relate to audit committees as set forth in Section 303A.02 of the NYSE Listed Company Manual and as set forth in Rule 10A-3 of the Securities Exchange Act of 1934, as amended (Exchange Act). The Audit Committee frequently meets in executive sessions and meets with the internal auditors and independent auditors outside the presence of management. All Audit Committee members qualify as audit committee financial experts.

Family Relationships

No director or executive officer is related to any other director or executive officer.

Section 16(a) Beneficial Ownership Reporting Compliance

Pursuant to Section 16(a) of the Exchange Act and regulations promulgated by the SEC, the Company's directors and officers subject to Section 16(a) and persons who beneficially own more than 10% of the Company's stock are required to file reports of ownership and changes in ownership with the SEC. The Company prepares reports for directors and officers subject to Section 16(a) based on information known and otherwise supplied, including information provided in response to director and officer questionnaires. Based on this information, the Company believes that all filing requirements under Section 16(a) of the Exchange Act with respect to the Company's directors and officers subject to Section 16(a) were satisfied in 2020.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Committee Interlocks and Insider Participation

The members of the Compensation Committee during 2020 were Mr. Jaggers, Mr. Baker, Dr. Robert F. Heinemann (who retired in May 2020), Mr. Minarovic, Dr. M.W. Scoggins (who retired in May 2020), Ms. Shafer-Malicki, and Mr. David A. Trice (who retired in May 2020). No member of our Compensation Committee was at any time prior to or during 2020, or the first two months of 2021, an officer or employee of our Company. Additionally, no member of the Compensation Committee had any relationship with our Company requiring disclosure as a related-person transaction. During 2020, no executive officer of our Company served on the compensation committee of any other entity that had one or more of its executive officers serving as a member of our Compensation Committee. Furthermore, no executive officer of our Company served on the Compensation Committee of another company that had one of its executive officers serve as a member of our Board.

COMPENSATION COMMITTEE REPORT

We have reviewed and discussed the Compensation Discussion and Analysis with management and, based on our review and discussions, have recommended to the Board that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for filing with the SEC.

By the Compensation Committee:

Joseph N. Jaggers, Chair
Phillips S. Baker, Jr.
Michael J. Minarovic
Mary Shafer-Malicki

This report shall not be deemed to be incorporated by reference by any general statement incorporating by reference this Annual Report on Form 10-K into any filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, and shall not otherwise be deemed filed under such acts.

COMPENSATION DISCUSSION AND ANALYSIS

This section describes the objectives and elements of the executive compensation programs for our Named Executive Officers (NEOs). Our NEOs for this Proxy Statement include our principal executive officer, our principal financial officer and our two other most highly compensated executive officers, who are the only individuals who served as executive officers during 2020. Our NEOs for 2020 are:

- Timothy J. Cutt, President and Chief Executive Officer (CEO)
- Christopher K. Woosley, Executive Vice President (EVP), Corporate Secretary and General Counsel
- William J. Buese, Vice President, Chief Financial Officer (CFO) and Treasurer
- Joseph T. Redman, Vice President, Energy

Executive Summary

Company Overview and 2020 Business Highlights

QEP is an independent crude oil and natural gas exploration and production (E&P) company with operations in two regions of the United States: the Southern Region (primarily in Texas) and the Northern Region (primarily in North Dakota).

2020 Business Highlights

Our Company delivered significant results and accomplishments in 2020:

- Generated a net income of $3.2 million, or $0.01 per diluted share;
- Reported $649.9 million of Adjusted EBITDA (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K), a 2% decrease from 2019;
- Reported net cash provided by operating activities of $673.2 million;
- Reported Free Cash Flow (a non-GAAP measure defined and reconciled in Item 7 of Part II of this Annual Report on Form 10-K) of $225.4 million in 2020 compared to Free Cash Flow outspend of $9.8 million in 2019;
- Reduced general and administrative expenses by 40% compared to 2019;
- Received $170.7 million in AMT credits refunds due to changes enacted by the CARES Act, inclusive of $5.6 million in interest income;
- Reduced principal amount of outstanding debt by $430.5 million;
- Recorded an additional income tax receivable of $61.6 million for AMT credit refunds related to NOL carrybacks due to changes enacted by the CARES Act;
- Reported year-end total proved reserves of 363.4 MMboe, including proved crude oil and condensate reserves of 237.9 MMbbls;
- Delivered oil and condensate production of 12.6 MMbbls in the Permian Basin;
- Delivered oil equivalent production of 30.3 MMboe;
- Incurred capital expenditures (excluding property acquisitions) of $327.9 million, a 43% decrease from 2019; and
- Entered into a definitive agreement on December 20, 2020, with Diamondback Energy, Inc. and Merger Sub, pursuant to which QEP will become a direct, wholly owned subsidiary of Diamondback.

During 2020, the novel Coronavirus disease (COVID-19) created unprecedented challenges for our industry, customers and employees. In early March, the Company took significant steps to reduce activity in the face of rapidly deteriorating market conditions, reducing drilling and completion activity in our core operating areas in the Permian and Williston basins and continuing to proactively manage its cash flow and preserve liquidity – a corporate strategy we adopted in 2019.

QEP remained focused on delivering value over volume throughout 2020 and our results exhibit both the strength of our core assets and the success of the financial and operational decisions we have made since early 2019. During 2020, we achieved industry-leading well costs in the Permian Basin, increased operational efficiencies in the two core basins in which we operate, and reduced G&A costs by 40% compared with 2019. As a result of these efforts, we delivered $225.4 million in Free Cash Flow in 2020, a record for the Company, which enabled us, along with our substantial AMT credit refunds, to reduce our principal amount of outstanding debt by $430.5 million and strengthen our balance sheet.

On December 20, 2020, QEP entered into an Agreement and Plan of Merger (Merger Agreement) with Diamondback Energy, Inc. (Diamondback) and Bohemia Merger Sub, Inc., a wholly owned subsidiary of Diamondback (Merger Sub), which provides that, among other things, and subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into QEP, with QEP surviving as a direct, wholly owned subsidiary of Diamondback (Merger). Pursuant to the Merger Agreement, at the effective time of the Merger, each outstanding share of common stock, par value $0.01 per share, of the Company (other than any Excluded Shares, any Converted Shares and Company Restricted Stock Awards (each as defined in the Merger Agreement)) will be converted into the right to receive 0.05 shares, par value $0.01 per share, of common stock of Diamondback (Merger Consideration). The Merger Agreement also addresses the treatment of QEP equity awards in the Merger. Diamondback's common stock is listed and traded on the NASDAQ Global Select Market under the symbol "FANG". The transaction was unanimously approved by the Boards of Directors of both companies. The Merger is expected to close late in the first quarter of 2021, and is subject to the approval of the Company's stockholders and other customary closing conditions.

Summary of 2020 Compensation Committee Actions

During 2020, the Compensation Committee took multiple actions to continue to strengthen our shareholders' confidence in our executive compensation programs, respond to the challenging economic environment caused by the COVID-19 pandemic, including its impact on the energy industry, and ensure the successful execution of the Merger.

Ongoing Compensation Program Actions

In an effort to continue our focus on operating cost-effectively in a volatile commodity market, be responsive to shareholders' comments to sharpen our focus on Free Cash Flow, and respond to the challenges created by the COVID-19 pandemic and its impact on the energy industry, our operations and our strategy, our Compensation Committee:

- Focused our 2020 Annual Incentive Plan (AIP) scorecard on Free Cash Flow and Health, Safety and Environmental (HSE) metrics with a cap on the ultimate payout score of 100% regardless if results were higher;
- Approved an overall 2020 AIP company score of 100% for our executives in line with the cap on the ultimate payout score even though the results were 162.6% due to the achievement of Free Cash Flow, significant cost reductions, increased capital efficiency and strong environmental and safety performance;
- Paid out the 2018 PSU awards at 15% of grant date target based upon our relative total shareholder return (TSR) performance score of 100% from January 1, 2018, to December 31, 2020, and the absolute share price reduction over the same period; and
- Restructured our peer group for the 2020 PSU award to generally reflect similarly-sized, oil-focused, public companies with primary operations in the Williston Basin in North Dakota and/or the Permian Basin in Texas.

Merger-Related Compensation Actions

In conjunction with the Merger, our Compensation Committee implemented several compensation-related actions to ensure the successful execution of the Merger as follows:

- Entered into a 12-month Non-Competition Agreement (Non-Competition Agreements) with each of Mr. Cutt, Mr. Woosley, Mr. Buese and Mr. Redman contemporaneously with and pursuant to the Merger Agreement; and
- In consideration for Mr. Cutt, Mr. Woosley, Mr. Buese and Mr. Redman entering into the Non-Competition Agreements, the Compensation Committee agreed to provide them with the following benefits:
    - Accelerated vesting in December 2020 of the outstanding restricted stock awards that would otherwise vest in March 2021;
    - Accelerated payment of the annual cash incentive bonus payment for 2020 paid at the target level in December 2020; and
    - A one-time transaction bonus (Transaction Bonus) paid in December 2020.

The one-time Transaction Bonus and related agreements require that Mr. Cutt, Mr. Woosley, Mr. Buese or Mr. Redman, as applicable, repay to the Company 100% of the Transaction Bonus if such NEO resigns for any reason prior to the consummation of the Merger, or, if the Merger is not consummated and such NEO resigns for any reason prior to December 31, 2021. The Transaction Bonuses were paid in the following amounts:

- A one-time cash transaction bonus of $1,250,000 for Mr. Cutt and Mr. Woosley;
- A one-time cash transaction bonus of $1,000,000 for Mr. Buese; and
- A one-time cash transaction bonus of $750,000 for Mr. Redman.

These one-time transaction bonuses were negotiated specifically in connection with the Merger Agreement and the Non-Competition Agreements and no additional bonuses related to the Merger are anticipated.

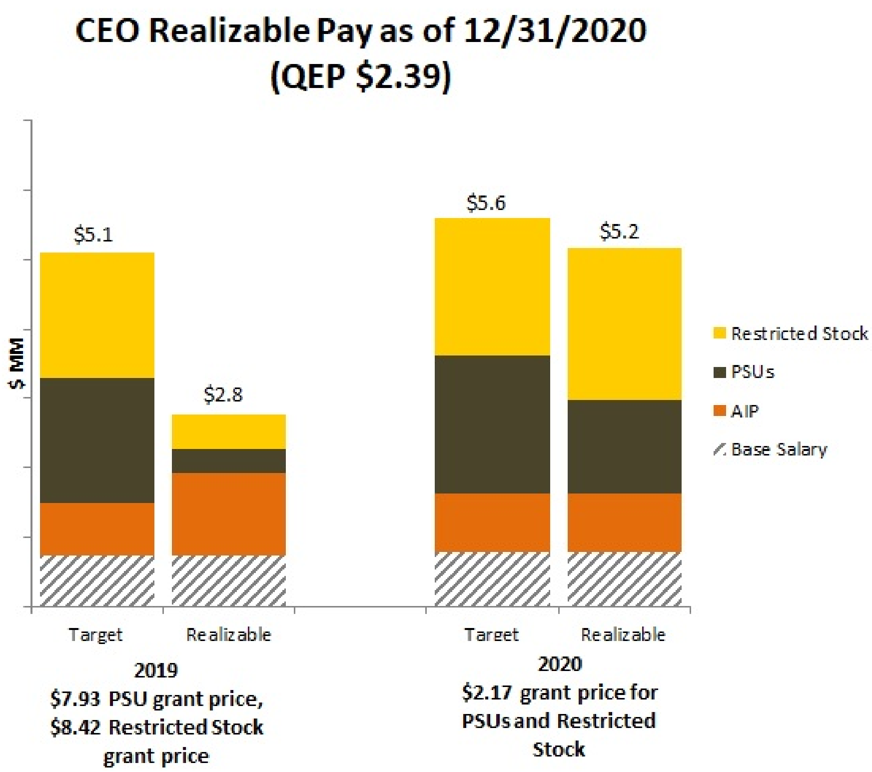
Succession Actions

Our Compensation Committee took actions related to the 2019 departure of one NEO, our prior EVP and CFO, and utilized our succession planning process related to this departure as follows:

- Promoted Mr. Woosley to EVP, General Counsel and Corporate Secretary effective January 1, 2020, at a target compensation package positioned as second-in-command to the CEO; and
- Promoted Mr. Buese as Vice President, CFO and Treasurer effective January 1, 2020, at a lower compensation package than our prior CFO, which is reflective of his seniority and experience and of the smaller, more focused company we are now versus prior years.

Realizable Pay Demonstrates Pay and Performance Alignment

Our pay programs are designed to align pay outcomes with both short-term and long-term Company strategy and performance, and we believe they are working as designed. Our CEO's actual realizable compensation based on performance has varied significantly from the intended target value, as illustrated by the graph below. As of December 31, 2020, Mr. Cutt's overall realizable compensation was 45% lower than his target compensation package for 2019 compensation and 7% lower than his target compensation package for 2020 compensation.



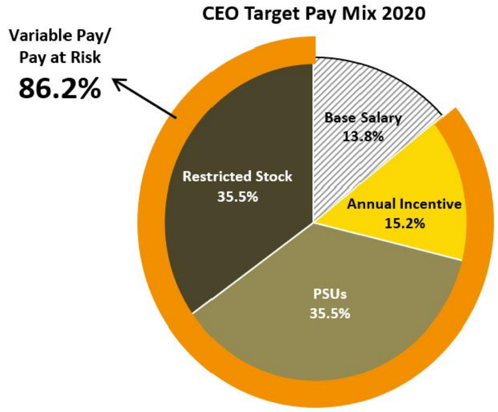
Grant Price is the fair value on the date of grant for PSUs and restricted stock, as reported in the Summary Compensation Table.

Target Pay includes base salary, target annual incentive and grant date fair value of PSUs and restricted stock.

Realizable Pay includes base salary, actual annual incentive paid (based on 100% formulaic, non-discretionary performance goals for 2019 and capped payout of 100% for 2020), period-to-date PSU performance for the 2019-2021 and 2020-2022 performance period as of December 31, 2020, and value of restricted stock awards at the December 31, 2020, stock price ($2.39).

The strong correlation between Company performance and our CEO's realizable pay, as reflected in the graph above, is a direct function of our CEO's pay mix and the design of our executive compensation programs.

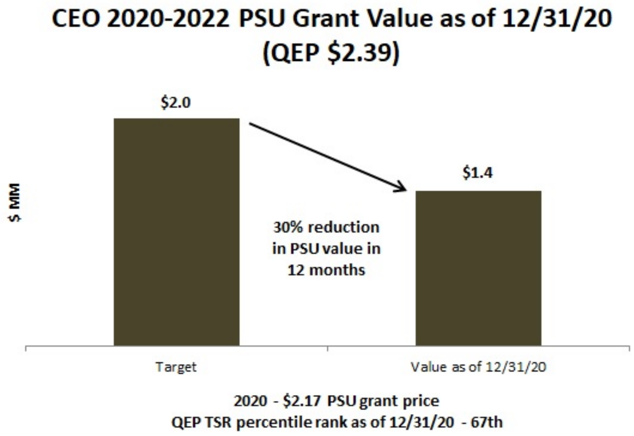
As shown in the graph below, 71% of our CEO's 2020 target total pay was tied to stock performance and 50.7% of our CEO's 2020 target total pay was tied to performance metrics (PSUs and Annual Incentive). This allocation equates to 86.2% of our CEO's 2020 pay being variable or at risk.



Based on the CEO's pay mix, changes in stock price over 2019 and 2020 alone have directly and substantially impacted the CEO's realizable pay, highlighting the link between pay and performance.

In addition to pay mix, the design of both our short-term and long-term incentives aligns realizable pay with Company performance:

- Our AIP metrics are based on short-term goals, the achievement of which the Compensation Committee expects will result in improved cash flow, returns on capital and greater shareholder value over time. Generally, the extent to which those goals are achieved directly impacts CEO realizable pay.
- Our long-term incentives are based primarily on share price, both on an absolute and relative basis. For example, our total shareholder return was at the 67th percentile of our peers for the 2020-2022 performance cycle as of December 31, 2020, but the performance-to-date value of the payout on the PSUs that would be earned by our CEO as of the end of the year (i.e. the realizable value) was approximately 30% below the grant date target value due to stock price performance.



Key Features of Our Executive Compensation Program

Our Executive Compensation Practices (What We Do)
Pay for Performance – We structure our CEO's compensation so that over 85% of our CEO's target total compensation varies based on performance (stock price and performance metrics).
Responsive to Shareholder Feedback – We seek shareholder input on our pay practices and regularly take action on feedback received.
Double Trigger Severance and LTI Award Vesting – Upon a change in control, LTI awards and cash benefits under our Executive Severance Plan (CIC Plan) vest or become payable only if the employee is terminated without Cause or constructively terminated within three years following the change in control.
Clawback Policy – AIP awards for our Section 16 Officers are subject to clawback in the event of a financial restatement due to fraud or misconduct, at the discretion of the Compensation Committee.
Executive Ownership Guidelines – Our stock ownership guidelines for our executives and directors are consistent with good corporate governance practices, requiring 6x base salary for our CEO, 3x for our EVP and 2x for other officers.
External Benchmarking – Our Compensation Committee reviews competitive compensation data based on an appropriate group of E&P peer companies prior to making annual compensation decisions.
Independent Compensation Consultant – Our Compensation Committee has engaged an independent executive compensation advisor who reports directly to the Compensation Committee and provides no other services to the Company.
Tally Sheets – Our Compensation Committee reviews comprehensive reports of each NEO's total compensation package prior to making executive compensation decisions.
Annual Risk Assessment of Compensation Practices – Our Compensation Committee conducts an annual risk assessment to consider carefully the degree to which compensation plans and decisions affect risk-taking. We do not believe that any of the compensation arrangements in place encourage unnecessary risk-taking.
Prohibited Executive Compensation Practices (What We Don't Do)
X **No Golden Parachute Excise Tax Gross-Ups** – We do not provide golden parachute excise tax gross-ups in our Executive Severance Plan or elsewhere.
X **No Repricing** – Our stock incentive plan does not permit the repricing of underwater stock options without shareholder approval.
X **No Hedging, Pledging or Derivatives Trading of QEP Stock** – These practices are strictly prohibited for all officers of the Company.
X **No Excessive Perquisites or Benefits** – We offer limited perquisites to our NEOs, consistent with the perquisites offered by our peer companies, to offset the cost of tax return preparation, financial planning and related expenses. Our supplemental retirement programs are limited to restoring the benefits lost under our qualified retirement plans, and eligibility is not limited to executives.
X **No Employment Agreements** – We have no employment agreements with any executive officers.

Compensation Philosophy and Objectives

In designing and administering our executive compensation program, our Compensation Committee is guided by an overall philosophy that emphasizes the following objectives:

Attract, retain and reward effective leaders. Our philosophy is to attract, retain and reward effective leaders by paying our executives competitively with our peers, with a majority of executive pay being earned over time and dependent on Company performance. In order to gauge whether our compensation structure is competitive with our peers, we evaluate the range of current industry compensation practices to provide external benchmarks that help to guide our executive compensation structure. Our Compensation Committee determines individual total compensation targets within this framework to provide compensation that correlates with QEP's relative performance to its peers. We do not, however, target a specific percentile of the peer market data. This approach provides the flexibility needed to manage our executive compensation programs to meet our current business needs.

Incentivize and pay for performance. Our executives should get paid more when the Company and our stock perform well and less when the Company and our stock are not performing well. To create the link between pay and performance, the majority of each of our NEO's compensation is based on the Company's attainment of short-term goals, long-term stock price performance and TSR performance on an absolute basis and relative to our industry peers.

Align our executives' interests with our shareholders' interests. Our executive compensation programs should incentivize our executives to think like shareholders and take into account shareholder concerns. Accordingly, a substantial portion of their compensation is provided in the form of long-term equity incentives that tie executive pay to stock performance. In addition, we require each of our NEOs to meet substantial stock ownership guidelines so that they have an investment in QEP and are incentivized to increase the value of that investment. We also engage in ongoing dialogue with our largest shareholders regarding executive compensation and governance matters, so that our executive compensation programs address any areas of concern.

Ensure appropriate management of risk. Our Compensation Committee believes that effective leadership in the oil and gas business requires taking prudent business risks while discouraging excessive risk-taking. To encourage this balance, our Compensation Committee has structured our compensation to include extended three-year vesting schedules on LTI awards, and generally, to base at least a portion of annual incentive awards on meeting strategic objectives regarding safety, legal and regulatory compliance. Annually, the Compensation Committee's independent compensation consultant conducts an assessment of our compensation programs to ensure that our programs do not encourage executives to take inappropriate or excessive risks that could negatively impact the Company. In addition, we strictly prohibit hedging, pledging or derivatives trading of QEP stock for all QEP executives and directors and have adopted a clawback policy.

Compensation Elements

Our compensation program for NEOs aligns with our compensation philosophy and incorporates elements designed to address a variety of objectives. The following table highlights each element of our compensation program and the primary role of such element in achieving our executive compensation objectives. Refer to specific sections of this Proxy Statement for more details on each program.

Compensation Element	Role in Total Compensation
Base Salary	• Provides fixed compensation based on an individual's skills, experience and proficiency, competitive market data and the relative value of the individual's role within the Company; and • Attracts and retains executive talent and helps the Company remain competitive in our industry.
Annual Incentive Program	• Motivates executives to achieve our strategic direction; • Rewards annual Company and individual performance; • Motivates participants to meet or exceed internal and external performance expectations; and • Recognizes individual contributions to the organization's results.
Long-Term Incentive Program Performance Share Units Restricted Stock	• Rewards long-term performance, directly aligned with shareholder interests; • Provides a strong performance-based equity component; • Recognizes and rewards share performance on an absolute basis and relative to industry peers; • Aligns compensation with sustained long-term value creation; • Allows executives to acquire a meaningful and sustained ownership stake; and • Fosters executive retention by vesting awards over multiple years.
Benefits Health & Welfare Retirement Deferred Compensation Other	• Attracts and retains executive talent and helps the Company remain competitive in our industry by offering a comprehensive employee benefits package; • Provides health and welfare benefits comparable to those provided to all other employees; • Provides financial security in the event of various individual risks and maximizes the efficiency of tax-advantaged compensation vehicles; and • Provides limited perquisites consistent with those offered by our peer companies.
Termination and Retention Benefits CIC Plan Transaction Bonus	• Attracts and retains executive talent as we execute a change in business strategy in a competitive and changing industry; • Seeks to ensure executives act in the best interests of shareholders in times of heightened uncertainty; and • Seeks to ensure retention of executives through the consummation of the Merger with Diamondback.

Base Salary

Our base salary program is designed to reward the NEOs with market competitive salaries based upon their role, experience, competence and sustained performance. In early 2020, the Compensation Committee made adjustments to the base salaries of Mr. Cutt and Mr. Redman in light of Company performance and competitive benchmarks, and also promoted Mr. Woosley to EVP, General Counsel and Corporate Secretary and Mr. Buese to VP, CFO and Treasurer and increased Mr. Woosley's and Mr. Buese's base salaries to reflect competitive benchmarks for their new roles. Salaries for our named executive officers for 2020 were as follows:

NEO	2019 Base Salary	2020 Base Salary	% Change
Mr. Cutt	$750,000	$775,000	3%
Mr. Woosley	$412,000	$450,000	9%
Mr. Buese	$273,000	$425,000	56%
Mr. Redman	$385,000	$396,550	3%

Annual Incentive Program

Our Compensation Committee approves annual cash awards pursuant to the AIP. As reflected in the table below, in early 2020 the Compensation Committee increased Mr. Cutt's AIP target from 100% to 110% as a result of competitive benchmarking and increased Mr. Woosley's AIP target from 80% to 90% and Mr. Buese's AIP target from 55% to 85% as a result of competitive benchmarking and their promotions.

NEO	2019 AIP Target (% of Base Salary)	2020 AIP Target (% of Base Salary)	% Change
Mr. Cutt	100%	110%	10%
Mr. Woosley	80%	90%	13%
Mr. Buese	55%	85%	55%
Mr. Redman[1]	64.2%	70%	9%

1. Mr. Redman's 2019 AIP target is prorated seven months at 60% and five months at 70% due to his promotion in August 2019.

As noted above, the COVID-19 pandemic had a significant impact on our operations and strategy for 2020. As a result of the pandemic and its impact on the energy industry, Management adjusted operational plans for 2020 to proactively manage cash flow and preserve liquidity through the management of production, capital expenditures, and operating costs. As a result, our Compensation Committee established a simplified AIP scorecard for 2020 focused on generating Free Cash Flow and HSE and eliminated the opportunity to earn above target. Even though the opportunity for earning above target was eliminated, our Compensation Committee established formulaic performance goals for our NEOs, to more accurately gauge and measure performance and results during 2020. The metrics and corresponding targets are based on the Compensation Committee's and Management's assessment of what would drive success and shareholder return during 2020. The table below summarizes the 2020 AIP metrics. Payout on each of the quantitative metrics ranges from 0% to 200%, with results interpolated between the 50% of target and 200% of target goals with a cap of 100% total payout as a result of the environment during 2020.

Metric	What It Is	Why We Used It	How We Set The Target
All NEOs			
Free Cash Flow (Non-GAAP) **(NEW)**	Adjusted EBITDA plus certain non-cash items that are included in Net Cash provided by (Used in) Operating Activities but excluded from Adjusted EBITDA less interest expense, excluding amortization of debt issuance costs and discounts, and accrued property, plant and equipment capital expenditures.	This metric is critical to management's and investors' analysis of the Company's ability to repay debt, fund acquisitions or repurchase stock.	The Board set the Free Cash Flow target based on the revised 2020 business plan, modified in response to the pandemic, and price adjusts (to plan pricing) actual results at year end to determine final results.
Total Recordable Incident Rate (TRIR)	Number of recordable injuries per 200,000 work hours.	Safety is a critical component of our business. We strive to ensure that all of our employees and contractors go home safely every day.	Based on Bureau of Labor Statistics data as reported in American Petroleum Institute (API) Workplace Injuries and Illness Report.
Environmental Severity Rate (spills) (Produced Fluid Release Rate (PFRR))	Number of barrels released per million barrels equivalent produced.	Our core values include operating in an environmentally responsible manner. We focus on measuring the severity of spills, not the number of spills.	Based on operator data reported in American Exploration & Production Council (AXPC) annual benchmarking survey results.
Hazard Identification and Reporting Rate (HIRR)	Number of near misses and safety observations per 200,000 work hours.	This metric provides a leading indicator of safety awareness and safe behaviors which reduces incidents.	Set by Board based on prior year results.

Management evaluated the Free Cash Flow metric and adjusted the 2020 results to remove the positive impacts on Free Cash Flow related to the North Dakota non-operated wells that were put on production earlier than originally forecasted and the increase in NGL production related to our decision to return to ethane recovery in the Permian Basin as NGL pricing improved. After these downward adjustments on the Free Cash Flow result, the 2020 performance for the NEOs' scorecard resulted in a Total Score payout percentage of 162.6%. Additionally, the Compensation Committee and Management adjusted the scorecard down to the 100% payout cap approved earlier in 2020 as a result of the impact of COVID-19 and the industry environment, which resulted in negative discretion of 62.6% on the payout of the total scorecard. The assessment of 2020 performance for the NEOs' scorecard is summarized in the following table:

Metric	Weight	Threshold 50%	Target 100%	Stretch 150%	Max 200%	Result	Score (Payout %)
Free Cash Flow[1]	90%	$155.0	$175.0	$195.0	$215.0	$200.8	164.0%
Health, Safety and Environment	10%						
Total Recordable Incident Rate		0.85	0.70	0.55	0.40	0.58	140%
Environmental Severity Rate (spills)		55	40	25	10	12	193%
Hazard Identification Reporting Rate		300	350	450	600	360	105%
Total Score							**162.6%**
Negative Discretion Applied							**(62.6%)**
Final Score							**100.0%**

1. The difference between Free Cash Flow reported in Item 7 of Part II of this Annual Report on Form 10-K and the Free Cash Flow calculated for the AIP score is primarily due to removing production related to the accelerated timing of non-operated wells in North Dakota and removing the increase in NGL production resulting from moving from ethane rejection to ethane recovery.

2020 AIP Payouts

Our Compensation Committee determined 2020 AIP payouts for our NEOs based on AIP scorecard performance and the 100% cap on payout for 2020.

The following table shows the 2020 AIP payouts for our NEOs:

NEO	2020 AIP Target (% of Base Salary)	Target Award ($)	2020 Scorecard Result	Final Award
Mr. Cutt	110%	$852,500	100.0%	$852,500
Mr. Woosley	90%	$405,000	100.0%	$405,000
Mr. Buese	85%	$361,250	100.0%	$361,250
Mr. Redman	70%	$277,585	100.0%	$277,585

Long-Term Incentive Program

Our long-term incentive (LTI) program is designed to align executive compensation with long-term stock price and TSR performance, both on an absolute basis and relative to industry peers. In early 2020, the Compensation Committee increased Mr. Cutt's LTI target from $3,600,000 to $3,972,500 to reflect competitive benchmarking and increased Mr. Woosley's LTI target from $1,110,000 to $1,500,000 and Mr. Buese's LTI target from $350,000 to $1,250,000 to reflect competitive benchmarking for their promotions.

The following table shows the 2020 LTI grant values:

NEO	2019 LTI Grant Value	2020 LTI Grant Value	% Change
Mr. Cutt	$3,600,000	$3,972,500	10%
Mr. Woosley[1]	$1,110,000	$1,500,000	35%
Mr. Buese[1]	$350,000	$1,250,000	257%
Mr. Redman[1]	$900,000	$900,000	—%

1. 2019 LTI grants shown reflect annual grant value and do not include one-time retention awards to Mr. Woosley, Mr. Buese and Mr. Redman.

Our Compensation Committee then determined how to deliver the total target LTI value through a mix of vehicles including performance share units (PSU) and restricted stock. In 2020, our LTI mix for NEOs was 50% restricted stock and 50% PSUs.

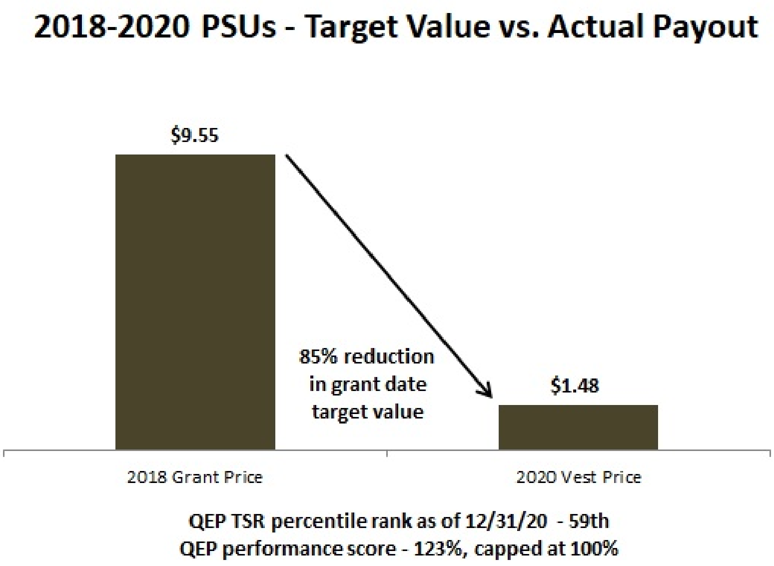
Performance Share Units

PSUs utilize phantom shares of stock that track the value of QEP shares but are typically settled in cash. PSUs align our executive compensation with the Company's TSR performance, both on an absolute basis and relative to our peers in the industry. The value realized for PSUs is dependent on both QEP's stock price and our TSR performance relative to our peers over a three-year period. The following chart summarizes the features of the PSU grants to our NEOs under our Cash Incentive Plan (CIP).

Performance Measure - Relative TSR	The payout is based on the Company's TSR over the performance period compared to the TSR of a group of peer companies over the same period. TSR combines share price appreciation and dividends paid, if any, to determine the total return to the shareholder. TSR is calculated using the average share price for the quarter immediately prior to the beginning and at the end of the performance period and dividends paid during that period.
Vesting	PSUs vest at the end of a three-year performance period and are payable in cash or shares upon Board certification in the first quarter of the following year.
Target Number of PSUs Awarded	The target number of PSUs awarded is determined by dividing the target dollar amount of LTI to be issued as PSUs by the closing price per share of QEP common stock on the grant date.
Peer Group	For awards with a 2020-2022 performance period, granted in March 2020, the peer group is outlined in the section below titled "*Compensation Process - Determination of Peer Group*".
Performance Scale	The performance scale is based on QEP's percentile rank in the peer group, with linear interpolation between each point: • 90th percentile or above: 200% score • 70th percentile: 150% score • 50th percentile: 100% score • 30th percentile: 50% score • Below 30th percentile: 0% score
Cap/Floor - Absolute TSR Performance	For all awards, a payout cap and floor applies based on absolute TSR performance. If QEP's TSR is between 0% and -25%, the payout is capped at 150% and if QEP's TSR is less than -25% the payout is capped at 100%. Likewise, if QEP's annualized TSR is greater than 15% during the performance period, the payout will be a minimum of 50%.
Payout Calculation	Cash payouts under the program at the end of the performance period are calculated using the following formula: Target # PSUs awarded times Performance Score times Average Q4 stock price of the final year of the performance period (Note: if awards are to be paid in shares, the same payout formula is used but would exclude the Average Q4 stock price component).
Termination Rules	For terminations without Cause or for Good Reason occurring prior to September 30, 2020, as such terms are defined in the February 2018 Participation Letters for our NEOs that expired on September 30, 2020, PSUs fully vest and are paid based on actual performance through the last day of the month prior to termination. Otherwise, shares automatically vest only upon an involuntary or constructive termination following a change in control (double trigger) per the terms of our Executive Severance Plan. See the "*Compensation Tables – Potential Payments Upon Termination or Change in Control*" section below for more information. In the event of retirement, death or disability, the number of PSUs is prorated based on termination date and paid based on actual performance at the end of the applicable performance period.

2018-2020 PSU Performance Period

The awards granted in February 2018 for the 2018-2020 performance period were eligible to vest upon the end of the performance period on December 31, 2020, subject to our relative and absolute TSR during the performance period as certified by our Compensation Committee. QEP’s TSR ranked at the 59th percentile of our peers, which would have resulted in a performance score of 123%. However, due to our negative shareholder return during the performance period, the number of PSUs earned was capped at 100% of target. The overall cash payout was equal to 15% of the original grant date value due to the share price decline since grant date.



The payout on the PSUs for the 2018-2020 performance period was as follows:

NEO	Target Award Value	Grant Price (2018)	Target PSUs	Performance Score	Vest Price (2020)	Cash Payout[1]	Cash Payout % of Target Award Value
Mr. Cutt	N/A	N/A	N/A	N/A	N/A	—	—%
Mr. Woosley	$555,008	$9.55	58,116	100%	$1.48	$86,012	15%
Mr. Buese	$140,003	$9.55	14,660	100%	$1.48	$21,697	15%
Mr. Redman	$200,006	$9.55	20,943	100%	$1.48	$30,996	15%

1. The payout calculation is Target # PSUs x % Performance Score (rounded up to whole shares) x Vest Price (Average Q4 stock price of final year of performance period).

Restricted Stock

Restricted stock aligns our executive compensation directly with the Company's market value (or stock price), encourages retention and increases employee ownership in the Company. The following chart summarizes the features of the restricted stock granted to our NEOs. The terms of the restricted stock awards are the same under both the LTSIP and LTIP.

Vesting	The vesting schedule of the grants extends over a three-year period, with one-third of the shares vesting each year, a feature that encourages retention.
Number of Shares Awarded	The number of shares awarded is determined by dividing the target dollar amount of LTI to be issued as restricted stock by the closing price per share of QEP common stock on the grant date.
Dividends	Dividends, if declared, are paid on unvested (restricted) shares.
Termination Rules	For terminations without Cause or for Good Reason occurring prior to September 2020, as such terms are defined in the February 2018 Participation Letters for our NEOs that expired September 30, 2020, all unvested shares fully vest. Otherwise, shares automatically vest only upon an involuntary or constructive termination following a change in control (double trigger) per the terms of our CIC Plan. See the "*Compensation Tables – Potential Payments Upon Termination or Change in Control*" section below for more information.

Compensation Process

Our Compensation Committee is guided by the compensation philosophy described above and utilizes the expertise and objectivity of the independent Consultant (defined below) and competitive benchmarking to ensure our executive compensation programs continue to support our business objectives.

Compensation Committee's Decision Making Process

Our Compensation Committee meets at least once per quarter to evaluate and oversee our compensation programs, with standing agenda items that align with responsibilities outlined in the Compensation Committee Charter and otherwise help the Compensation Committee fulfill its responsibilities.

In the first quarter of each year, the Compensation Committee:

- Assesses risks associated with our compensation programs;
- Approves key financial, operational and strategic goals and weightings for the current year AIP based on recommendations and input from management;
- Selects the peer group for the PSU awards and compensation benchmarking;
- Establishes targeted compensation for the NEOs, including base salary, AIP target award and LTI grant value;
- Assesses overall company performance against goals in the prior year;
- Assesses performance of each NEO;
- Determines payout amounts for the prior year AIP, including, in its sole discretion, increases or decreases to individual NEO awards; and
- Certifies results for outstanding PSU awards.

With the support of the Consultant, the Compensation Committee recommends total compensation for the CEO, which is approved by all of the independent directors.

At subsequent meetings throughout the year, our CEO provides updates on progress toward our AIP goals and relative TSR performance under outstanding PSU awards. The Compensation Committee also receives updates on governance and regulatory trends and analysis and benchmarking provided by the Consultant.

In the third quarter of each year, the Consultant conducts a benchmarking analysis to use as a reference point for assessing the competitiveness of our executive compensation programs. The peer group benchmarking analysis includes the 25th, 50th and 75th percentiles for each component of compensation (base salary, AIP and LTI) and total compensation for the roles of each of our officers, including the NEOs. Our Compensation Committee does not target a specific percentile from this analysis, but uses all the data points as guidance to allow for informed decisions. This approach provides flexibility to our Compensation Committee to address several different factors such as proficiency in role, scope of role, succession potential and internal pay equity.

To support specific compensation decisions, the Compensation Committee also reviews information provided by tally sheets, including stock ownership levels and calculations of potential payments upon various termination events.

Role of the Chief Executive Officer/Other Officers

The Compensation Committee considers input from the CEO when assessing overall Company performance, as well as individual performance of our other NEOs. The CEO does not participate in discussions or recommendations regarding his own compensation. Our CEO provides a written assessment of his performance to the independent directors at the end of each year. In the first quarter, the Board meeting agenda includes a discussion of the CEO's performance evaluation. In addition to the competitive analysis and other support provided by the Consultant, the Vice President, Human Resources and Community Investments and her team also provide information to our Compensation Committee to aid the decision-making process, including executives' current compensation information, succession potential, organizational considerations, alignment with internal employee programs and Company performance. The Vice President, Human Resources and Community Investments does not participate in discussions or recommendations regarding her own compensation.

Role of the Independent Compensation Consultant

Our Compensation Committee has engaged Meridian Compensation Partners, LLC (Consultant) as its independent compensation consultant to help ensure that our executive compensation programs are competitive and consistent with our compensation philosophy. In making this decision, the Compensation Committee considered the following:

- The Consultant's historical performance in supporting the Compensation Committee and its familiarity with our executive compensation programs;
- The Consultant's extensive experience and familiarity with compensation programs of our peer companies and sector;
- The range of compensation services offered by the Consultant; and
- The independence of the Consultant, considering the independence factors outlined by the NYSE.

Our Compensation Committee determined the scope of the engagement, which included:

- Providing benchmarking data on executive and outside director compensation for the Compensation Committee to use in its decision-making process;
- Providing input into plan design discussions and individual compensation actions, as needed;
- Evaluating any risks to our Company due to our executive compensation program;
- Reviewing plan design and recommendations periodically;
- Reviewing and providing feedback on the compensation-related disclosures in our Proxy Statement;
- Discussing the shareholder engagement process and the results of shareholder engagement and the Say on Pay Vote; and
- Informing the Compensation Committee about recent trends, best practices and other developments affecting executive compensation.

The Consultant does not provide any other services to the Company. The Consultant attended all Compensation Committee meetings, including executive sessions as requested. The Consultant on occasion met with the Chair of the Compensation Committee or with members of management, including the CEO and Vice President, Human Resources and Community Investments, in carrying out these duties, but reported exclusively to our Compensation Committee. The Compensation Committee determined that the Consultant's work in 2020 did not create any conflicts of interest and that the Consultant remains independent.

Determination of Peer Group

Our Compensation Committee maintains a peer group of companies, which consists of similarly-sized, publicly traded oil and natural gas E&P companies that have similar operating and financial characteristics to us, as they represent QEP's primary competition for executive talent. With the assistance of our CEO and the Consultant, our Compensation Committee reviews the composition of the peer group annually to ensure that companies remain relevant for comparative purposes. The Compensation Committee uses a peer group for determining relative TSR performance under the PSU program and for benchmarking executive compensation.

In preparation for the 2020 compensation cycle, our Compensation Committee reviewed the peer group to ensure it generally reflects similarly sized, oil-focused, publicly traded companies with most peers having primary operations in the Permian Basin and Williston Basin. The Compensation Committee used the following peer group to determine executive compensation benchmarking in preparation for 2020 compensation decisions.

2020 Executive Compensation Peer Group		
Callon Petroleum Co.	Laredo Petroleum Inc.	SM Energy Co.
Carrizo Oil & Gas Inc.	Matador Resources Co.	SRC Energy Inc.
Centennial Resource Development Inc.	Oasis Petroleum Inc.	Whiting Petroleum Corp.
Extraction Oil & Gas Inc.	PDC Energy Inc.	WPX Energy Inc.
Jagged Peak Energy Inc.		

In January 2020, the Compensation Committee approved an adjusted peer group for the PSU Plan as a result of consolidation activity in the market and to ensure the peer group was relevant for a three year plan cycle by focusing on: 1) publicly traded companies, 2) companies with similar financial characteristics, 3) companies with a similar asset mix, and 4) companies with a focus on oil production. The Compensation Committee identified the following peer group for determining relative TSR performance for our PSU awards for the 2020 to 2022 performance period. New companies for 2020 are denoted with an asterisk (*) and the following companies were removed for 2020 as a result of being acquired: Carrizo Oil & Gas, Inc., Jagged Peak Energy, Inc. and SRC Energy, Inc.

2020 Relative TSR Peer Group		
Callon Petroleum Co.	Laredo Petroleum Inc.	PDC Energy Inc.
Centennial Resource Development Inc.	Magnolia Oil & Gas Corp.*	SM Energy Co.
Extraction Oil & Gas Inc.	Matador Resources Co.	Whiting Petroleum Corp.
HighPoint Resources Corp.*	Oasis Petroleum Inc.	WPX Energy Inc.

Key Executive Compensation Design Policies and Considerations

Following are important policies and factors considered by our Compensation Committee when structuring our executive compensation.

Severance Protections

The CIC Plan provides certain benefits to our executives upon a qualifying termination after a change in control of the Company. These benefits are based on a review of market practices and do not include any excise tax gross-ups. Our Compensation Committee believes these benefits support our business strategy by encouraging our executive officers to execute on our strategic initiatives and consider other strategic alternatives to increase shareholder value without regard to the impact on their future employment. In addition, in 2018, we also implemented an Executive Severance Program that would have provided certain benefits to our executives upon a termination without Cause or a termination for Good Reason. However, this program expired September 30, 2020, and was not renewed. For additional details regarding our CIC Plan, see the "*Compensation Tables - Potential Payments Upon Termination or Change in Control*" section below.

Executive Share Ownership Guidelines

Our Compensation Committee believes it is important to have stock ownership guidelines for executive officers to promote ownership of our common stock and align the interests of our executive officers with those of our shareholders. Our executives are required to achieve the applicable level of stock ownership within five years of the date the person first becomes an executive officer. If an executive officer has not met the required ownership level as of their five-year anniversary in the role, or has since fallen below the required ownership level as a result of a decrease in stock price, such executive officer is prohibited from selling or transferring any company stock except for amounts necessary to pay income tax liabilities related to the vesting of restricted company stock. Shares that count toward satisfaction of the guidelines include shares owned outright by the executive, restricted shares, shares held in the 401(k) Plan (described below), phantom stock attributable to deferred compensation under a deferred compensation wrap plan (Wrap Plan, described below) and PSUs.

The ownership guidelines for our NEOs are currently established at the following minimum levels:

NEO	Guideline	Ownership Status as of 12/31/20
Mr. Cutt	6x base salary	In compliance
Mr. Woosley	3x base salary	In compliance
Mr. Buese	2x base salary	In compliance
Mr. Redman	2x base salary	In compliance

Tax and Accounting Considerations

Our Compensation Committee considers tax and accounting rules and regulations when structuring the executive compensation paid to our NEOs, including the following:

- Under Section 280G and Section 4999 of the Internal Revenue Code of 1986, as amended (the Code), compensation that is granted, accelerated or enhanced upon the occurrence of a change in control may give rise, in whole or in part, to "excess parachute payments" and, to such extent, will be non-deductible by the Company and will be subject to a 20% excise tax payable by the executive. Our compensation arrangements do not provide for gross-ups for this excise tax.

- Section 162(m) of the Code, as modified by the Tax Cuts and Jobs Act of 2017, generally precludes us from deducting for tax purposes compensation paid in excess of $1,000,000 in any taxable year to any "covered employee" (generally, any individual that has ever been listed in the Summary Compensation Table for our 2017 or later proxy statements), unless the compensation is paid pursuant to a written contract that was in existence on or prior to November 2, 2017, and either (i) qualifies as "performance-based compensation" or (ii) is otherwise exempt under certain Section 162(m) grandfathering rules. Our policy is primarily to design and administer compensation plans that support the achievement of short- and long-term strategic objectives and enhance shareholder value. Where it is consistent with our compensation philosophy, the Compensation Committee expects that it may issue compensation that is non-deductible.

- Section 409A of the Code requires that nonqualified deferred compensation be deferred and paid under plans or arrangements that satisfy the requirements of the statute with respect to the timing of deferral elections, the timing of payments and certain other matters. Failure to satisfy these requirements can expose our employees and other service providers to accelerated income tax liabilities and penalty taxes and interest on their vested compensation under such plans or arrangements. Our Compensation Committee endeavors to structure executive compensation in a manner that is either compliant with, or exempt from the application of, Section 409A of the Code, although there is no guarantee that any particular element of compensation will, in fact, be so compliant or exempt.

- Fair Value of Stock-Based Payments – Awards of stock options and restricted stock under the LTSIP and/or 2018 LTIP and awards of performance share units under the CIP are accounted for under Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 718 (FASB ASC Topic 718), formerly referred to as SFAS No. 123(R). FASB ASC Topic 718 requires the recognition of expense for the fair value of stock-based compensation or, in the case of awards settled in cash (such as our PSUs), requires the recognition of expense based on the cash liability of such awards adjusted each measuring period. Our Compensation Committee considers the accounting and financial statement impact in evaluating QEP's executive compensation programs.

Assessment of Our Executive Compensation Program's Impact on Risk Taking

We annually evaluate the major risks to our business, including how risks taken by management could impact the value of executive compensation. Our Compensation Committee reviews a risk assessment (completed by the Consultant) of the Company's executive and non-executive compensation programs. Based on this review, our Compensation Committee believes that while there are certain risks inherent in the nature of the Company's business, the Company's compensation programs do not encourage our executives or our non-executive employees to take inappropriate or excessive risks. The risk-mitigating factors considered by our Compensation Committee included the following:

- An appropriate balance of strategic, operating and financial performance measures, which generally include operational metrics specifically targeted at the health and safety aspects of the Company's business;
- A compensation clawback policy for amounts paid under the AIP (see the "*Clawback of Compensation"* section below);
- An appropriate balance of fixed and Company performance-related compensation components;
- A mix of cash and equity, with significant weight placed on LTI awards;
- Significant stock ownership requirements and policies prohibiting hedging, pledging and engaging in derivative transactions for all executives;
- Extended three-year vesting schedules on equity grants;
- Caps and defined thresholds for payout on most incentive awards; and
- Compensation Committee authority over plan design and final determination of actual compensation awards.

Our Compensation Committee believes that these factors encourage all of our employees to focus on QEP's sustained long-term performance.

Prohibition on Hedging, Pledging and Derivatives Trading

The Company has a policy that prohibits directors, executive officers and certain other employees who are in possession of material non-public information from engaging in derivative transactions involving any of QEP's securities for any purpose, including short-term trading, options trading, pledging, trading on margin and hedging.

Clawback of Compensation

Upon the recommendation of our Compensation Committee, our Board of Directors adopted a clawback policy in 2015 in advance of final SEC rules implementing Section 954 of the Dodd-Frank Act. Pursuant to this policy, AIP payouts to our Section 16 officers are subject to clawback in the event of a restatement of our financial statements due to fraud or misconduct, at the discretion of the Compensation Committee. Our Compensation Committee will continue to monitor the status of the anticipated SEC rules to ensure our clawback policy complies with final rules when they are implemented.

Succession Planning

QEP conducts a comprehensive succession planning process that involves assessment across the organization of employee performance and potential and readiness of potential successors for key roles and developmental needs. This process also helps inform our Compensation Committee in making compensation decisions. Our Compensation Committee annually reviews this process with specific focus on the CEO and his direct reports and views this as a critical process to ensure continuity of our business and to provide challenging and rewarding career opportunities for our employees.

COMPENSATION TABLES

Summary Compensation Table

The following table summarizes the total compensation paid to our NEOs for services rendered during the fiscal years ended 2020, 2019 and 2018, except that only 2020 and 2019 compensation is summarized for Mr. Cutt and Mr. Redman as they were not NEOs in 2018, and only 2020 compensation is summarized for Mr. Buese as he was not a NEO in 2019 or prior.

Name and Principal Position	Year	Salary	Bonus	Stock Awards[1]	Non-Equity Incentive Plan Compensation[2]	All Other Compensation[3]	Total[4]
(a)	(b)	($)	($)	($)	($)	($)	($)
		(c)	(d)	(e)	(f)	(g)	(h)
Timothy J. Cutt President and CEO	2020	769,792	1,250,000[5]	4,137,975	852,500	18,500	7,028,767
	2019	690,745	350,000	3,600,009	1,182,000	136,987	5,959,741
	2018	—	—	—	—	—	—
Christopher K. Woosley Executive Vice President and General Counsel	2020	448,417	1,250,000[5]	1,570,355	405,000	118,329	3,792,101
	2019	402,300	750,000	1,360,011	519,450	78,892	3,110,653
	2018	396,458	—	1,110,016	470,400	71,102	2,047,976
William J. Buese Vice President, CFO and Treasurer	2020	418,667	1,000,000[5]	1,296,402	361,250	89,824	3,166,143
	2019	—	—	—	—	—	—
	2018	—	—	—	—	—	—
Joseph T. Redman Vice President, Energy	2020	394,144	750,000[5]	939,165	277,585	93,387	2,454,281
	2019	325,583	750,000	1,150,009	389,358	59,399	2,674,349
	2018	—	—	—	—	—	—

1. Amounts in column (e) include awards of PSUs and restricted stock, in each case calculated based on the grant date fair values determined in accordance with FASB ASC Topic 718 (excluding the effect of estimated forfeitures), as follows for 2020:

Name	Performance Share Units[a,b] ($)	Restricted Stock[b,c] ($)
Mr. Cutt	1,986,251	2,151,724
Mr. Woosley	750,002	820,353
Mr. Buese	625,001	671,401
Mr. Redman	450,002	489,163

a. The maximum grant date values of the PSUs assuming the highest level of performance achievement (based upon QEP's common stock price on the date of issuance, assuming that each individual ultimately earns 200% of the total number of PSUs granted, and excluding any amounts attributed to modifications for our departed NEOs as described in footnote c below) are as follows: Mr. Cutt, $3,972,502; Mr. Woosley, $1,500,004; Mr. Buese, $1,250,002 and Mr. Redman, $900,004.

b. The grant date fair values for the 2020 PSU and restricted stock awards were determined pursuant to FASB ASC Topic 718 (excluding the effect of estimated forfeitures) by multiplying the number of units/shares awarded times the QEP stock price on the date of grant.

c. Restricted stock values include shares that were awarded in a prior year and were subject to a modification in 2020 on account of the accelerated vesting as a result of the consideration provided for each executive entering into a Non-Competition Agreement related to the announced Merger. The dollar amount shown reflects the value of shares granted in 2020 plus the incremental fair value resulting from the modification and computed as of the modification date in accordance with FASB ASC Topic 718 as follows: Mr Cutt, $165,473; Mr. Woosley, $70,351; Mr. Buese, $46,400 and Mr. Redman, $39,162.

2. Amounts in column (f) reflect the annual cash incentive awards (i.e., the AIP awards) for 2020, which were determined by the Compensation Committee in December 2020 and paid out on December 31, 2020.
3. Amounts in column (g) include employer matches under the 401(k) Plan and the Wrap Plan. Employer matches under the Wrap Plan are as set forth in column (c) of the 2020 Nonqualified Deferred Compensation table. No amounts were included for perquisites and personal benefits, as the aggregate value of perquisites and personal benefits for each executive was less than $10,000.
4. As reflected in the Summary Compensation Table above, the salary received by each of our NEOs as a percentage of his respective total compensation was as follows:

Name	Year	Percentage of Total Compensation
Mr. Cutt	2020	11.0%
	2019	11.6%
Mr. Woosley	2020	11.8%
	2019	12.9%
	2018	19.4%
Mr. Buese	2020	13.2%
Mr. Redman	2020	16.1%
	2019	12.2%

5. Column (d) reflects a one-time Transaction Bonus paid to Messers. Cutt, Woosley, Buese and Redman in 2020 as consideration provided for each executive entering into a Non-Competition Agreement related to the Merger. The Transaction Bonus and related agreements require that the NEO repay to the Company 100% of the Transaction Bonus if the NEO resigns for any reason prior to the consummation of the Merger, or, if the Merger is not consummated, prior to December 31, 2021.

Grants of Plan-Based Awards for 2020

This table sets forth the plan-based awards granted to the NEOs during 2020. For non-equity and equity incentive plans, it provides the ranges of possible awards. For stock and option awards, the table sets forth the number of shares of restricted stock or stock options granted and the grant date fair values of those awards.

Name	Grant Date		Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1]			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)
			Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)		
Timothy J. Cutt	3/2/20	AIP[1]	[2]	852,500	1,705,000					
	3/2/20	PSU[3]				457,662	915,323	1,830,646		1,986,251
	3/2/20	RS[4]							915,323	1,986,251
	12/28/20	RS[5]							376,367	165,473
Christopher K. Woosley	3/2/20	AIP[1]	[2]	405,000	810,000					
	3/2/20	PSU[3]				172,812	345,623	691,246		750,002
	3/2/20	RS[4]							345,623	750,002
	12/28/20	RS[5]							157,909	70,351
William J. Buese	3/2/20	AIP[1]	[2]	361,250	722,500					
	3/2/20	PSU[3]				144,010	288,019	576,038		625,001
	3/2/20	RS[4]							288,019	625,001
	12/28/20	RS[5]							112,164	46,400
Joseph T. Redman	3/2/20	AIP[1]	[2]	277,585	555,170					
	3/2/20	PSU[3]				103,687	207,374	414,748		450,002
	3/2/20	RS[4]							207,374	450,002
	12/28/20	RS[5]							90,105	39,162

1. The amounts included reflect estimated future cash payouts under the AIP of our CIP based on a targeted percentage of actual base salaries for 2020. AIP payouts earned in 2020 are reflected in the Non-Equity Incentive Plan Compensation column (f) of the "*Summary Compensation Table*" above.
2. There is no applicable threshold for the AIP.
3. This row represents the range of the number of PSUs that may be earned with respect to PSUs granted pursuant to our CIP in 2020. Payment for earned awards is made in cash or shares after the end of the three-year performance period ending December 31, 2022. If the threshold level of performance of 30% is not met, then actual payout will be zero. If the absolute TSR is negative, then the payout will be capped.
4. This row sets forth the annual grants of restricted stock pursuant to our LTIP during 2020.
5. As noted in footnote 1.c of the "*Summary Compensation Table*" above, these shares were awarded in a prior year and were subject to a modification in 2020 on account of the accelerated vesting as a result of the consideration provided for each executive entering into a Non-Competition Agreement related to the announced Merger. The dollar amount shown represents the incremental fair value resulting from the modification and computed as of the modification date in accordance with FASB ASC Topic 718.

Outstanding Equity Awards at Fiscal Year-End 2020

This table shows outstanding equity awards for the NEOs. All values shown are as of December 31, 2020.

	Option Awards				Stock Awards			
					Restricted Stock		PSUs	
Name (a)	Number of Shares of Common Stock Underlying Unexercised Options Exercisable (#) (b)	Number of Shares of Common Stock Underlying Unexercised Options Unexercisable (#) (c)	Option Exercise Price ($) (d)	Option Expiration Date (e)	Number of Shares or Units of Stock That Have Not Vested (#) (f)	Market Value of Shares or Units of Stock That Have Not Vested ($) (g)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (h)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (i)
Timothy J. Cutt					71,259 [1]	170,309	226,987 [4]	542,499
					610,215 [2]	1,458,414	915,323 [5]	2,187,622
Christopher K. Woosley	12,535	—	31.74	2/13/2021	23,329 [1]	55,756	69,988 [4]	167,271
	29,528	—	21.69	2/12/2022	230,415 [2]	550,692	345,623 [5]	826,039
	26,645	—	10.12	2/16/2023				
	27,856	—	16.98	2/13/2024				
William J. Buese	2,778	—	31.47	6/2/2021	8,827 [1]	21,097	17,655 [4]	42,195
	9,843	—	21.69	2/12/2022	192,012 [2]	458,909	288,019 [5]	688,365
	9,869	—	10.12	2/16/2023				
	9,053	—	16.98	2/13/2024				
Joseph T. Redman	9,203	—	7.52	9/1/2024	10,508 [1]	25,114	88,184 [4]	210,760
					37,772 [3]	90,275	207,374 [5]	495,624
					138,249 [2]	330,415		

1. 100% of these awards will vest on March 5, 2022.
2. 50% of these awards will vest on March 5, 2022 and 50% will vest on March 5, 2023.
3. 50% of these awards will vest on September 5, 2021 and 50% will vest on September 5, 2022.
4. Awards will vest on December 31, 2021 (the end of the three-year performance period covered by the PSU), but are not payable until Board certification, which occurs in the first quarter of the following year. These amounts represent the target number of PSUs awarded under our CIP in 2019. Each PSU represents a contingent right to receive one share of QEP common stock or the fair market value of one share of QEP common stock. The actual number of shares that may be earned (and, therefore, the actual cash payout amount, if settled in cash) will range from 0% to 200% of the number of PSUs awarded, depending on QEP's relative TSR in comparison to a peer group of companies during the three-year period ending December 31, 2021 and is subject to certain caps and thresholds.
5. Awards will vest on December 31, 2022 (the end of the three-year performance period covered by the PSU), but are not payable until Board certification, which occurs in the first quarter of the following year. These amounts represent the target number of PSUs awarded under our CIP in 2020. Each PSU represents a contingent right to receive one share of QEP common stock or the fair market value of one share of QEP common stock. The actual number of shares that may be earned (and, therefore, the actual cash payout amount, if settled in cash) will range from 0% to 200% of the number of PSUs awarded, depending on QEP's relative TSR in comparison to a peer group of companies during the three-year period ending December 31, 2022, and subject to certain caps and thresholds.

Option Exercises and Stock Vested in 2020

Name	Options Exercised		Stock Awards[1]	
	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
Timothy J. Cutt	0	0	447,626	$1,025,957
Christopher K. Woosley	0	0	298,105 [2]	$597,543
William J. Buese	0	0	170,755 [2]	$356,497
Joseph T. Redman	0	0	190,988 [2]	$361,434

1. Amounts shown in these columns reflect restricted stock awards that vested during 2020 (including restricted shares that were scheduled to vest in March 2021 and accelerated as a result of the consideration provided for each executive entering into the Non-Competition Agreement related to the announced Merger, as described in footnote 1.c of the "*Summary Compensation Table"* above) and payouts of PSUs for the 2018-2020 performance period. The values realized on vesting of the restricted stock are calculated based on the closing price per share of QEP common stock on the vesting date multiplied by the number of shares vested, and the values realized on payout of the PSUs are calculated based on the average closing price per share of QEP common stock during the final quarter of the performance period multiplied by the number of PSUs earned (100% of PSUs granted in 2018), pursuant to the terms of the PSU awards. Values are as follows:

Name	Restricted Stock		PSUs	
	Number of Shares (#)	Value	Number of PSUs (#)	Value
Mr. Cutt	447,626	$1,025,957	0	$0
Mr. Woosley	239,989	$511,531	58,116	$86,012
Mr. Buese	156,095	$334,800	14,660	$21,697
Mr. Redman	170,045	$330,438	20,943	$30,996

2. Includes vesting of 2019 Retention Awards for Mr. Woosley, Mr. Buese and Mr. Redman.

Savings Plans

Employee Investment Plan (401(k) Plan)

QEP offers its employees, including its NEOs, the opportunity to make both tax-deferred and Roth after-tax contributions to the 401(k) Plan, plus any catch-up contributions, if eligible. The IRS 401(k) maximum combined tax-deferred and Roth contribution limit was $19,500 for 2020. The catch-up maximum contribution limit for participants who turned age 50 or older during the Plan year was $6,500 for 2020.

The Company makes contributions that match employee contributions. Participants received an employer matching contribution equal to 100% of the participant's contributions up to 8% of their eligible compensation for the year ended December 31, 2020.

The employee deferrals and employer contributions are invested, as directed by the participant, in mutual funds or QEP common stock.

Deferred Compensation Wrap Plan

QEP allows officers, along with certain other key employees, to defer the receipt of compensation under a deferred compensation wrap plan (Wrap Plan). The Wrap Plan includes both a deferred compensation program and a 401(k) supplemental program.

Deferred Compensation Program of the Wrap Plan
This program allows officers and certain key employees to defer taxable income and provide for future financial needs. Eligible employees currently may defer up to 50% of base salary and up to 100% of their annual cash incentives, payouts on PSUs and restricted stock grants pursuant to this program. Base salary and annual cash incentive amounts deferred under this program are eligible for discretionary Company matching contributions, and the Company has generally matched such contributions at the same rate as in the 401(k) Plan.

401(k) Supplemental Program of the Wrap Plan
This program allows NEOs and certain key employees whose compensation exceeds the IRS limit on compensation that may be taken into account for qualified plan purposes ($285,000 in 2020) to defer up to 8% of their base salaries and annual cash incentives in excess of the IRS limit. The Company provides a matching contribution on this deferred amount as if that amount had been contributed to the 401(k) Plan.

Gains and losses on the deferred amounts are tracked against participant-selected investments. Participants select their investments from a variety of investment options, including QEP phantom stock and an array of mutual funds.

2020 Nonqualified Deferred Compensation

Name (a)	Executive Contributions in Last FY[1,2] ($) (b)	Company Contributions in Last FY[3] ($) (c)	Aggregate Earnings in Last FY[4] ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE[5] ($) (f)
Timothy J. Cutt	—	—	—	—	—
Christopher K. Woosley	97,885	87,029	131,879	—	980,768
William J. Buese	61,824	61,824	(9,669)	—	279,805
Joseph T. Redman	71,597	65,387	118,234	—	978,255

1. The NEOs automatically participate in the QEP 401(k) Supplemental Program of the Wrap Plan when their compensation exceeds the IRS limit, unless they decline participation (Mr. Cutt declined participation in 2020). For those who do participate, 8% of qualified compensation in excess of the IRS limit is automatically contributed pursuant to the QEP 401(k) Supplemental Program and NEOs receive an employer match of 8% as if contributed to the 401(k) Plan.

2. In 2020, Messrs. Woosley and Redman each deferred compensation under the Wrap Plan. Amounts deferred receive the same applicable employer match as if contributed to the 401(k) Plan.
3. Amounts contributed by the Company pursuant to the Wrap Plan are included in the All Other Compensation column (g) of the "*Summary Compensation Table"* above.
4. Aggregate earnings are not included in the "*Summary Compensation Table*" above because they do not consist of any above-market or preferential earnings.
5. Due to a payroll coding error, certain federal employment taxes were not withheld with respect to amounts deferred under our Wrap Plan from 2011 through 2016. The employment tax error with respect to 2013 through 2016 was corrected in 2017. The Company will pay the employee and employer shares of the employment taxes for 2011 and 2012 and an additional amount to account for income taxes with respect to the payment of the employee shares when distributions under the Wrap Plan are made in the future. The aggregate balances shown in the table as of December 31, 2020, exclude the following estimated amounts payable by the Company for such payments: Mr. Woosley, $1,296; Mr. Redman, $1,349.

Potential Payments Upon Termination or Change in Control

Change in Control: Executive Severance Plan

Pursuant to the Executive Severance Plan (CIC Plan), each of our executives is entitled to certain severance benefits if he or she is terminated for any reason other than for "Cause," death or disability, or if the executive terminates employment for "Good Reason," at any time following consummation of a change of control and prior to the third anniversary thereafter (a "Qualifying Termination").

Assuming there is a Qualifying Termination within three years after a change in control, the severance benefits upon termination under the CIC Plan include the following:

- A cash severance payment equal to 3x (in the case of Mr. Cutt and Mr. Woosley) or 2x (in the case of the other NEOs) the sum of annual base salary and the average of the AIP award the executive actually received for the three fiscal years prior to the change in control (for executives with fewer than 3 years of AIP award payments, the AIP component will be the average of the years the executive received an AIP payout or target AIP if the executive has not previously received an AIP award payment);
- A prorated award from the AIP for the year of termination;
- Accelerated vesting of PSUs granted under the CIP;
- Equity incentive awards under the LTSIP and LTIP will vest in full; and
- Medical, dental and vision insurance coverage, basic and supplemental life insurance, and accidental death or dismemberment coverage under current employee plans for two years (three years, in the case of Mr. Cutt and Mr. Woosley) at no cost to the executive.

Under the CIC Plan, a change in control is deemed to have occurred if:

(i) Any person (within the meaning of Section 13(d)(3) or 14(d)(2) of the Exchange Act) other than a trustee or other fiduciary holding securities under an employee benefit plan of the Company, is or becomes the beneficial owner (as such term is used in Rule 13d-3 under the Exchange Act) of securities of the Company representing 30% or more of the combined voting power of the Company;

(ii) The following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, as of June 30, 2010, constitute the Company's Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's shareholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on June 30, 2010, or whose appointment, election or nomination for election was previously so approved or recommended;

(iii) The Company's shareholders approve a merger or consolidation of the Company or any direct or indirect subsidiary of the Company with any corporation, other than a merger or consolidation that would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof) at least 60% of the combined voting power of the securities of the Company or such surviving entity or its parent outstanding immediately after such merger or consolidation, or a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the beneficial owner, directly or indirectly, of securities of the Company representing 30% or more of the combined voting power of the Company's then outstanding securities; or

(iv) The Company's shareholders approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 60% of the combined voting power of the voting securities of which are owned by the shareholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale. A change in control, however, shall not be considered to have occurred until all conditions precedent to the transaction, including but not limited to, all required regulatory approvals have been obtained.

Under the CIC Plan, "Good Reason" means any of the following events or conditions that occur without the participant's written consent and remain in effect after notice has been provided by the participant to the Company of such event and the expiration of a 30-day cure period:

(i) A material diminution in the participant's annual base salary, target bonus under the AIP or LTI award opportunity under the CIP or LTIP;
(ii) A material diminution in the participant's authority, duties or responsibility;
(iii) A material diminution in the authority, duties or responsibilities of the supervisor to whom the participant is required to report, including a requirement that a participant report to a corporate officer or employee instead of reporting directly to the Board;
(iv) A material diminution in the budget over which the participant retains authority;
(v) A material change in the geographic location at which the participant performs services; or
(vi) Any other action or inaction that constitutes a material breach by an employer of the participant's employment agreement (if any).

Under the CIC Plan, "Cause" means (i) the willful and continued failure of the participant to substantially perform the participant’s duties (other than any such failure resulting from incapacity due to physical or mental illness), following written demand for substantial performance delivered to the participant by the Board or the CEO; or (ii) the participant willfully engaging in conduct which is materially injurious to the Company.

Payments Upon Termination

The following table sets forth the estimated payments due to active NEOs under various termination scenarios and as reviewed by the Compensation Committee, assuming the termination occurred on December 31, 2020. The table generally does not include amounts due to all salaried employees upon termination, such as any accrued paid time off. There are no amounts payable in connection with a resignation or a termination for Cause; accordingly, no amounts are shown for these scenarios.

Compensation Component	Death or Disability	Qualifying Termination Within 3 Years After a Change in Control[1]
Plan Providing for Payment	LTSIP/LTIP/CIP	Executive Severance Plan
Cash Severance	N/A	(i) 2-3x base salary + 2-3x three-year average annual incentive paid[2] (ii) Cash payment representing 2-3 years of COBRA premiums
Annual Incentive	Prorated award	Prorated award
Equity Awards (Restricted Stock and Stock Options)	Accelerated vesting of all unvested awards	Accelerated vesting of all unvested awards

Performance Share Units	Prorated award based on performance through the end of the performance period	Accelerated vesting and payment of all unvested awards based on actual performance period-to-date (CIC)
Retirement Benefits	(3)	(3)
Mr. Cutt		
Cash Severance	—	$5,383,305
Annual Incentive	$852,500	$852,500
Equity Awards	$1,628,723	$1,628,723
PSUs	$1,090,873	$2,730,121
Total	$3,572,096	$10,594,649
Mr. Woosley		
Cash Severance	—	$2,855,291
Annual Incentive	$405,000	$405,000
Equity Awards	$606,448	$606,448
PSUs	$525,758	$1,132,208
Total	$1,537,206	$4,998,947
Mr. Buese		
Cash Severance	—	$1,463,165
Annual Incentive	$361,250	$361,250
Equity Awards	$480,005	$480,005
PSUs	$292,623	$765,598
Total	$1,133,878	$3,070,018
Mr. Redman		
Cash Severance	—	$1,494,556
Annual Incentive	$277,585	$277,585
Equity Awards	$445,804	$445,804
PSUs	$355,768	$756,437
Total	$1,079,157	$2,974,382

1. A "Qualifying Termination" under the CIC Plan refers to a termination of the executive's employment by QEP without Cause or by the executive for Good Reason.
2. For executives with fewer than 3 years of AIP award payments, the AIP component will be the average of the years the executive received an AIP payout or target AIP if the executive has not previously received an AIP award payment.
3. Upon any triggering event each of the NEOs is eligible for benefits under the Wrap Plan. See the "*Savings Plans - 2020 Nonqualified Deferred Compensation*" table above for an estimated value of such benefits.

CEO Pay Ratio

The SEC requires disclosure of the CEO to median employee pay ratio. Mr. Cutt's 2020 total compensation was $7,028,767 as reported in the "*Summary Compensation Table*." Our median employee's total compensation for 2020 was $196,383. As a result, Mr. Cutt's total compensation for 2020 was approximately 36 times that of our median employee's total compensation.

In determining our median employee, we defined compensation using a consistently applied compensation measure to include annualized base salary plus any additional wages (e.g. overtime earnings), annual incentive paid and grant date fair value of long-term incentives. Rather than using the same median employee from 2019, we determined a new median employee for 2020 due to changes in our workforce. We determined our median employee based on our employee population (including part-time employees) as of December 1, 2020, which is within the last three months of our fiscal year.

As compared with 2019, median employee total compensation decreased in 2020 due to a decrease in company score for 2020 Annual Incentive Payouts versus 2019, which impacts all employees. As a result of decreased median employee total compensation and the increase in Mr. Cutt's compensation relative to last year due to the one-time transaction bonus in conjunction with the Merger, the ratio between CEO and median employee pay is 29% higher in 2020 as compared with 2019.

Director Compensation Table

The table below sets forth total director compensation earned by each independent director during 2020.

Name	Fees Earned or Paid in Cash[1] ($)	Stock Awards[2] ($)	Total ($)
Phillips S. Baker, Jr.[3]	81,500	175,002	256,502
Julie A. Dill[4]	90,250	175,002	265,252
Robert F. Heinemann[5]	40,625	175,002	215,627
Joseph N. Jaggers[6]	84,625	175,002	259,627
Michael J. Minarovic	75,250	175,002	250,252
M. W. Scoggins[7]	35,000	175,002	210,002
Mary Shafer-Malicki[8]	97,750	175,002	272,752
David A. Trice[9]	46,250	215,001	261,251
Barth E. Whitham	75,250	175,002	250,252

1. Certain directors deferred director fees under the Director Deferred Compensation Plan as follows: Ms. Dill, $90,250; and Dr. Scoggins, $35,000.
2. The dollar amount indicated for each of these restricted stock awards under the LTIP is the aggregate grant date fair value computed in accordance with FASB ASC Topic 718, by multiplying the number of shares awarded by the QEP stock price on the date of grant. All independent directors of QEP, except Mr. Jaggers, elected to defer their grant of QEP restricted stock and to receive phantom stock. The number of shares of restricted stock granted and number of shares deferred as phantom stock in 2020 and the outstanding aggregate phantom stock balances as of December 31, 2020, for each director were as follows:

Name	Number of Restricted Shares/Restricted Stock Units Issued in 2020 (#)	Number of Restricted Shares Deferred as Phantom Stock in 2020 (#)	Phantom Stock Balances as of 12/31/20 (#)
Phillips S. Baker, Jr.	—	80,646	195,859
Julie A. Dill	—	80,646	183,085
Robert F. Heinemann	—	80,646	—
Joseph N. Jaggers	80,646	—	—
Michael J. Minarovic	—	80,646	143,146
M. W. Scoggins	—	80,646	—
Mary Shafer-Malicki	—	80,646	142,270
David A. Trice	—	99,079	48,161
Barth E. Whitham	—	80,646	101,904

3. Mr. Baker was appointed as our Governance and Social Responsibility Committee Chair in May 2020, and received a committee chair retainer of $6,250 in addition to his board retainer of $70,000.
4. In 2020, Ms. Dill served as our Audit Committee Chair and received a committee chair retainer of $15,000 in addition to her board retainer of $70,000.
5. Dr. Heinemann served as our Compensation Committee Chair until he retired from the board on May 12, 2020, and received a committee chair retainer of $5,625 in addition to his board retainer of $35,000. The board accelerated the vesting of his 80,646 shares of unvested deferred phantom stock, which was valued at $65,323 on the date of acceleration.
6. Mr. Jaggers was appointed as our Compensation Committee Chair in May 2020, and received a committee chair retainer of $9,375 in addition to his board retainer of $70,000.
7. Dr. Scoggins retired from the board on May 12, 2020, and received a board retainer of $35,000. The board accelerated the vesting of his 80,646 shares of unvested deferred phantom stock, which was valued at $65,323 on the date of acceleration.
8. Ms. Shafer-Malicki was appointed as our Chair of the Board in May 2020, and received a Chair of the Board retainer of $18,750. She served as our Governance and Social Responsibility Committee Chair until May 2020, and received a committee chair retainer of $3,750 in addition to her board retainer of $70,000.
9. Mr. Trice served as our Chair of the Board until he retired from the board on May 12, 2020, and received a Chair of the Board retainer of $11,250, a board retainer of $35,000 and the additional Chair of the Board restricted stock grant . The board accelerated the vesting of his 99,079 shares of unvested deferred phantom stock, which was valued at $80,254 on the date of acceleration.

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

SECURITY OWNERSHIP

The information provided below summarizes the beneficial ownership of our common stock by our named executive officers, each of our directors, all of our executive officers and directors as a group, and persons owning more than 5% of our common stock. "Beneficial ownership" generally includes those shares of common stock held by someone who has investment and/or voting authority of such shares or has the right to acquire such common stock within 60 days. The ownership includes common stock that is held directly and also stock held indirectly through a relationship, a position as a trustee, or under a contract or understanding.

Directors and Executive Officers

The following table lists the shares of our common stock beneficially owned by each director, named executive officer, and all directors and executive officers as a group as of February 17, 2021, except as indicated below. Shares not outstanding but deemed beneficially owned by virtue of the right of a person to acquire shares within 60 days of February 17, 2021, are included as outstanding and beneficially owned for that person but are not treated as outstanding for the purpose of computing the percentage ownership of any other person. Except as noted in the footnotes below, the holders have sole voting and dispositive powers over the shares. Except for any arrangements to be triggered upon the closing of the Merger expected to occur by the end of the first quarter 2021, the Company has no knowledge of any arrangement that would, at a subsequent date, result in a change in control of the Company.

	Amount and Nature of Beneficial Ownership			
Name	**Common Stock Beneficially Owned**	**Common Stock Acquirable Within 60 Days**	**Total Beneficially Owned**	**Percent of Class[4]**
Timothy J. Cutt	970,597 [1,2]	—	970,597	*
Christopher K. Woosley	471,851 [1,2]	84,029	555,880	*
William J. Buese	334,016 [1,2]	31,543	365,559	*
Joseph T. Redman	356,594 [1,2]	9,203	365,797	*
Phillips S. Baker, Jr.	28,897	195,859 [3]	224,756	*
Julie A. Dill	5,525	183,085 [3]	188,610	*
Joseph N. Jaggers	120,570	-	120,570	*
Michael J. Minarovic	60,000	143,146 [3]	203,146	*
Mary Shafer-Malicki	—	142,270 [3]	142,270	*
Barth E. Whitham	—	101,904 [3]	101,904	*
All directors and executive officers (10 individuals)	2,348,050	891,039	3,239,089	1.34%

1. Includes the following unvested restricted shares for which the owners have sole voting power, but which cannot be disposed of until they vest: Mr. Cutt owns 681,474 shares; Mr. Woosley owns 253,744 shares; Mr. Buese owns 200,839 shares; Mr. Redman owns 186,529 shares.
2. Does not include the following executives' long-term cash incentive amounts measured in performance share units (PSUs) pursuant to the QEP Cash Incentive Plan, which are subject to a cash payout to the extent certain performance objectives are achieved: Mr. Cutt owns 1,142,310 PSUs; Mr. Woosley owns 415,611 PSUs; Mr. Buese owns 305,674 PSUs; Mr. Redman owns 295,558 PSUs.
3. Represents fully-vested phantom stock units held in the QEP Deferred Compensation Plan for Directors, which are payable in cash or shares of QEP common stock (at the director's election) upon termination of the director's service on the Board.
4. The percentage of shares owned is less than 1% unless otherwise stated.

Certain Beneficial Owners

The following table sets forth information with respect to each person known by the Company to beneficially own more than 5% of our common stock as of February 17, 2021.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
BlackRock, Inc., 55 East 52nd Street, New York, NY 10055	24,517,648[1]	10.10%
Dan H. Wilks, 17018 IH 20, Cisco, TX 76437	17,820,000[2]	7.36%
FMR, LLC., 245 Summer Street, Boston, MA 02210	15,919,969[3]	6.55%
The Vanguard Group, Inc. 100 Vanguard Blvd., Malvern PA 19355	15,048,175[4]	6.19%
Key Group Holdings (Cayman) Ltd., 3C Caves Point, West Bay Street, Nassau Bahamas	13,657,842[5]	5.60%

1. Based on its Schedule 13G/A filed with the SEC on January 8, 2021, as of December 31, 2020, BlackRock, Inc. had sole voting power of 24,434,281 shares and sole dispositive power of 24,517,648 shares.
2. Based on the Schedule 13G/A jointly filed with the SEC on February 16, 2021 by Dan H. Wilks, Staci Wilks, THRC Management, LLC, THRC Holdings, LP, Wilks Brothers, LLC and Farris Wilks as of December 31, 2020, Dan H. Wilks and Staci Wilks had shared voting power of 17,820,000 shares and shared dispositive power of 17,820,000 shares. THRC Holdings, LP had shared voting power of 17,500,000 shares and shared dispositive power of 17,500,000 shares. THRC Management, LLC, as General Partner of THRC Holdings, LP, has exclusive voting and investment power over the shares of QEP common stock held by THRC Holdings, LP, and therefore may be deemed to beneficially own such shares. Dan H. Wilks, as sole Manager of THRC Management, LLC, together with his spouse, Staci Wilks, who shares the same household, may be deemed to exercise voting and investment power over an additional 320,000 shares of QEP common stock directly owned by THRC Holdings, LP and therefore may be deemed to beneficially own such shares. Wilks Brothers, LLC beneficially owns 0 shares of QEP common stock and is a manager-managed limited liability company, managed by Dan H. Wilks and Farris Wilks. Dan H. Wilks and Farris Wilks are brothers and may be deemed to indirectly beneficially own the shares of QEP common stock directly beneficially owned by Wilks Brothers.
3. Based on its Schedule 13G filed with the SEC on February 8, 2021, as of December 31, 2020, FMR LLC had sole voting power of 2,580,037 shares and sole dispositive power of 15,919,969 shares.
4. Based upon its Schedule 13G/A filed with the SEC on February 10, 2021, as of December 31, 2020, The Vanguard Group, Inc. had shared voting power of 42,410 shares; shared dispositive power of 116,810 shares and sole dispositive power of 14,931,365 shares.
5. Based on its Schedule 13G/A filed with the SEC on February 8, 2021, as of December 31, 2020, Key Group Holdings (Cayman) Ltd. had sole voting power of 13,657,842 shares and sole dispositive power of 13,657,842 shares. Millinvest, Ltd. is the owner of Key Group Holdings (Cayman) Ltd. and Sunil Jagwani is the ultimate beneficial owner of Millinvest, Ltd. Because Millinvest, Ltd. is the owner of Key Group Holdings (Cayman) Ltd. and Mr. Jagwani is the ultimate beneficial owner of Millinvest, Ltd., they may be deemed to share voting and dispositive power over the shares of QEP common stock managed by Key Group Holdings (Cayman) Ltd. on behalf of the clients and accounts. As a result, they may also be deemed to beneficially own the securities held by the clients or accounts of Key Group Holdings (Cayman) Ltd.

EQUITY COMPENSATION PLAN INFORMATION

In 2018, QEP's Board and QEP's shareholders approved the QEP Resources, Inc. 2018 Long-Term Incentive Plan (LTIP), which replaces the 2010 Long-Term Stock Incentive Plan (LTSIP). As of December 31, 2020, shares of our common stock are authorized for issuance to directors, officers, employees and consultants under the LTIP. All outstanding awards relate to our common stock.

Plan Category	Number of Shares of Common Stock to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (#)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares of Common Stock Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (#)
	(a)	(b)	(c)
Equity Compensation Plans Approved by Shareholders	1,491,184	$18.94	2,899,444
Equity Compensation Plans Not Approved by Shareholders	—	—	—
Total	1,491,184	$18.94	2,899,444

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

Director Independence

The Board evaluated all relationships between the Company and its directors and determined that all non-management directors currently serving on the Board are independent under all applicable rules and regulations, including the listing requirements of the NYSE, as set forth in Section 303A.02 of the NYSE Listed Company Manual, and the Company's Corporate Governance Guidelines. The Board also determined that no independent director has a material relationship with the Company that could impair the director's independence. The criteria applied by our Board in determining independence is available in our Corporate Governance Guidelines, which are located on the Company's website at http://ir.qepres.com/static-files/b6178067-4202-4829-be93-ca10ee83d11e. The Board evaluates independence on an ongoing basis.

CERTAIN RELATIONSHIPS AND TRANSACTIONS WITH RELATED PERSONS

Transactions with related persons are those that involve our directors, executive officers, director nominees, greater than 5% shareholders, immediate family members of these persons or entities in which one of these persons has a direct or indirect material interest. Pursuant to the procedures described below, we review all transactions that would involve amounts exceeding $120,000 (the current threshold required to be disclosed in this Annual Report on Form 10-K under SEC regulations) and certain other similar transactions.

During the year ended December 31, 2020, there were no reportable transactions with related persons.

Policies and Procedures for Review and Approval of Related-Person Transactions

Pursuant to the terms of our Corporate Governance Guidelines, we require that all executive officers and directors report to our Corporate Secretary or Assistant Corporate Secretary any event or anticipated event that might qualify as a related-person transaction. The Corporate Secretary or Assistant Corporate Secretary then reports those transactions to the Audit Committee. We also collect information from questionnaires sent to executive officers and directors early each year that are designed to reveal related-person transactions. If a report or questionnaire shows a potential related-person transaction, our Audit Committee will review the transaction in accordance with our Code of Conduct. The Audit Committee will review pending and ongoing transactions to determine whether they conflict with the best interests of the Company, impact a director's independence or conflict with our Code of Conduct. If the transaction is completed, the Audit Committee will determine whether rescission of the transaction, disciplinary action or reevaluation of independence is required. If a waiver to the Code of Conduct is granted to an executive officer or director, the nature of the waiver will be disclosed on our website (www.qepres.com), in a press release or on a current report on Form 8-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit Fees

On October 21, 2019, the Company dismissed PricewaterhouseCoopers LLP (PwC) as the Company’s independent registered accounting firm, effective upon completion of their audit of the Company’s consolidated financial statements for the year ended December 31, 2019. This decision was approved by the Audit Committee of the Company's Board of Directors.

The report of PwC on the Company's consolidated financial statements for the year ended December 31, 2019 did not contain any adverse opinion or a disclaimer of opinion, nor was it qualified or modified as to uncertainty, audit scope, or accounting principles.

During the fiscal year ended December 31, 2019 there were no (i) disagreements with PwC on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements if not resolved to their satisfaction, would have caused them to make reference to the subject matter of the disagreement in connection with their report, or (ii) reportable events (as described in Item 304(a)(1)(v) of Regulation S-K).

The Company has provided PwC with a copy of the above disclosures, and PwC has furnished the Company with letters dated October 23, 2019 and March 4, 2020 addressed to the Securities and Exchange Commission (SEC) stating that it agrees with the statements made above. A copy of PwC’s letter, dated October 23, 2019, is attached as Exhibit 16.1 to the Company’s Current Report on Form 8-K filed on October 23, 2019. A copy of PwC's letter, dated March 4, 2020, is attached as Exhibit 16.1 to the Company's Current Report on Form 8-K filed on March 4, 2020.

On March 3, 2020, the Audit Committee formally engaged Deloitte & Touche LLP (Deloitte) as the Company’s independent registered public accounting firm for the year ending December 31, 2020, replacing PwC. During the years ended December 31, 2020 and 2019, the Company did not consult with Deloitte regarding any of the matters or events set forth in Item 304(a) (2) (i) or (ii) of Regulation S-K.

Aggregate fees for professional services rendered for the Company by PWC for the years ended December 31, 2019 and 2020 were:

Type of Fees	2019	2020
Audit Fees[1]	$1,290,000	$66,000
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees[2]	$5,000	—
Total	$1,295,000	$66,000

1. Audit fees for 2019 and 2020 are for the audit of the Company's 2019 consolidated financial statements included in the Form 10-K, including the audit of the effectiveness of the Company's internal controls over financial reporting and the reviews of the Company's financial statements included in the Form 10-Q, and review of the Company's other filings with the SEC.
2. All other fees relate to consultation and licenses for accounting research software.

Aggregate fees for professional services rendered for the Company by Deloitte for the years ended December 31, 2019 and 2020 were:

Type of Fees	2019	2020
Audit Fees[1]	—	$845,000
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees[2]	—	$2,000
Total	—	$847,000

1. Audit fees for 2020 are for the audit of the Company's consolidated financial statements included in the Form 10-K, including the audit of the effectiveness of the Company's internal controls over financial reporting and the reviews of the Company's financial statements included in the Form 10-Q, and review of the Company's other filings with the SEC.
2. All other fees relate to licenses for accounting research software.

The Audit Committee has concluded that the provisions of other fees are compatible with maintaining PwC's and Deloitte's independence.

Preapproval Policy

The Audit Committee has adopted procedures for preapproving all audit and non-audit services provided by the Company's independent registered public accounting firm. These procedures include reviewing fee estimates for audit services and permitted recurring non-audit services and authorizing the Company to execute letter agreements setting forth such fees. Audit Committee approval is required for any services to be performed by the Company's independent registered public accounting firm that are not specified in the letter agreements. We have delegated approval authority to the Chair of the Audit Committee, but any exercises of such authority are reported to the Audit Committee at the next meeting. All fees for audit and non-audit services provided by the Company's independent registered public accounting firm for the years ended December 31, 2019 and 2020 were preapproved by the Audit Committee in accordance with this policy.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial statements and financial statement schedules filed as part of this report are listed in the index included in Item 8 of Part II Financial Statements and Supplementary Data of this report.

(b) **Exhibits.** The following is a list of exhibits required to be filed as a part of this report in Item 15(b).

Exhibit No.	Description
2.1	Agreement and Plan of Merger among Diamondback Energy Inc., Bohemia Merger Sub, Inc., and QEP Resources, Inc., dated as of December 20, 2020 (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 21, 2020).
3.1	Amended and Restated Certificate of Incorporation dated May 15, 2018 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 17, 2018)
3.2	Amended and Restated Bylaws dated October 27, 2020 (incorporated by reference to Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on October 28, 2020).
4.1	Indenture, dated as of March 1, 2012, between the Company and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 1, 2012)
4.2	Officer's Certificate, dated as of March 1, 2012 (including the form of the 5.375% Notes due 2022) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on March 1, 2012)
4.3	Officer's Certificate, dated as of September 12, 2012 (including form of the 5.250% Notes due 2023) (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on September 14, 2012)
4.4	Officer's Certificate, dated as of November 21, 2017 (including the form of the 5.625% Senior Notes due 2026) (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K, filed with the Securities Exchange Commission on November 21, 2017)
4.5*	Description of the Company's Securities
10.1	Credit Agreement, dated as of August 25, 2011, among QEP Resources, Inc., Wells Fargo Bank, National Association, as the administrative agent, letter of credit issuer and swing line lender, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 29, 2011)
10.2	First Amendment to Credit Agreement, dated as of July 6, 2012 (incorporated by reference to Exhibit 10.2 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 26, 2020)
10.3	Second Amendment to Credit Agreement, dated as of August 13, 2013 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on August 16, 2013)
10.4	Third Amendment to Credit Agreement, dated as of January 31, 2014 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on May 7, 2014)
10.5	Fourth Amendment to Credit Agreement and Commitment Increase Agreement, dated as of December 2, 2014 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 4, 2014)
10.6	Fifth Amendment to the Credit Agreement, dated as of November 23, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on November 23, 2015)
10.7	Sixth Amendment to the Credit Agreement, dated as of May 5, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on May 9, 2017)
10.8	Seventh Amendment to the Credit Agreement, dated as of November 21, 2017 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on November 27, 2017)
10.9	Eighth Amendment to Credit Agreement, dated as of June 4, 2020, by and among QEP Resources, Inc., Wells Fargo Bank, National Association, in its capacity as administrative agent for the lenders, the lenders party thereto and the guarantors party thereto (incorporated by reference to Exhibit 10.1 to the Company’s Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 4, 2020).
10.10+	Employee Matters Agreement, dated as of June 14, 2010, by and between Questar Corporation and QEP Resources, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 16, 2010)
10.11+	Amended and Restated QEP Resources, Inc. Deferred Compensation Wrap Plan, dated May 15, 2017 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 26, 2017)

10.12+	Amended and Restated QEP Resources, Inc. Deferred Compensation Plan for Directors, dated July 24, 2017 (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 26, 2017)
10.13+	Cash Incentive Plan, dated effective as of January 1, 2012 (incorporated by reference to Appendix A to the Company's Proxy Statement on Schedule 14A, filed with the Securities and Exchange Commission on April 3, 2012)
10.14+	Amendment Number One to the Cash Incentive Plan, effective as of October 26, 2015 (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.15+	2010 Long-Term Stock Incentive Plan, adopted June 12, 2010 (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 16, 2010)
10.16+	Amendment Number One to 2010 Long-Term Stock Incentive Plan, effective as of October 26, 2015 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.17+	2018 Long-Term Incentive Plan, as adopted on May 15, 2018 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on May 17, 2018)
10.18+	Executive Severance Compensation Plan - CIC, as Amended and Restated Effective as of October 26, 2015 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.19+	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.8 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on November 5, 2013)
10.20+	Supplemental Executive Retirement Plan, effective as of January 1, 2016 (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on August 3, 2015)
10.21+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to the CEO and CFO in 2012 and 2013 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010)
10.22+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers other than the CEO and CFO in 2012 and 2013 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010)
10.23+	Form of Nonqualified Stock Option Agreement for nonqualified stock options granted to executive officers under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.3, to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on January 23, 2014)
10.24+	Form of Amendment to Certain Stock Option Agreements under the QEP Resources, Inc. 2010 Long-Term Stock Incentive Plan adopted January 20, 2014 (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on January 23, 2014)
10.25+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2016 and 2017 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on October 29, 2015)
10.26+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2018 under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.17 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 28, 2018)
10.27+	Form of Restricted Stock Agreement for restricted stock granted to executive officers in 2019 under the 2018 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 25, 2018)
10.28+	Form of Restricted Stock Agreement for restricted stock granted to non-employee directors under the 2018 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.27 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 26, 2020)
10.29+	Form of Phantom Stock Agreement for phantom stock granted to non-employee directors under the 2010 Long-Term Stock Incentive Plan (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on June 29, 2010)
10.30+	Form of Performance Share Unit Award Agreement for performance share units granted to executive officers under the 2012 Cash Incentive Plan (incorporated by reference to Exhibit 10.33 to the Company's Annual Report on Form 10-5, filed with the Securities and Exchange Commission on February 22, 2017)

10.31+	Form of Deferred Share Award Agreement for shares of common stock granted to executives under the 2018 Long-Term Incentive Plan and for deferral of receipt of such shares in accordance with the terms of the Deferred Compensation Wrap Plan - Deferred Compensation Program (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on July 25, 2018)
10.32+	Form of Retention Letter, dated December 5, 2018, between the Company and certain executive officers (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 6, 2018)
10.33	Letter Agreement, dated August 6, 2019, by and between QEP Resources, Inc. and Elliott Management Corporation (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q, filed with the Securities and Exchange Commission on August 7, 2019)
10.34+	Letter Agreement, dated February 19, 2019, with Richard J. Doleshek (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 20, 2019)
10.35+	Form of Deferred Share Award Agreement for shares of common stock granted to non-employee directors under the 2018 Long-Term Incentive Plan and for deferral of receipt of such shares in accordance with the terms of the Director Deferred Compensation Plan (incorporated by reference to Exhibit 10.1 to the Company' Quarterly Report on form 10-Q, filed with the Securities and Exchange Commission on August 7, 2019)
10.36+	Executive Severance Compensation Plan – CIC, as Amended and Restated Effective as of August 7, 2019 (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed by the Company with the Securities and Exchange Commission on August 7, 2019)
10.37+	Form of Non-Competition Agreement, dated as of December 20, 2020, by and between QEP Resources, Inc. and the Executives (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 28, 2020)
10.38+	Form of Letter Agreement, dated as of December 20, 2020, by and between QEP Resources, Inc. and the Executives (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, filed with the Securities and Exchange Commission on December 28, 2020)
21.1*	Subsidiaries of the Company
23.1*	Consent of Independent Registered Public Accounting Firm - Deloitte & Touche LLP
23.2*	Consent of Independent Registered Public Accounting Firm – PricewaterhouseCoopers LLP
23.3*	Consent of Independent Petroleum Engineers and Geologists – Ryder Scott Company, L.P.
24*	Power of Attorney
31.1*	Certification signed by Timothy J. Cutt, QEP Resources, Inc. President and Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification signed by William J. Buese, QEP Resources, Inc. Vice President, Chief Financial Officer, Treasurer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification signed by Timothy J. Cutt and William J. Buese, QEP Resources, Inc. President and Chief Executive Officer and Vice President, Chief Financial Officer and Treasurer respectively, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Qualifications and Report of Independent Petroleum Engineers and Geologists – Ryder Scott Company, L.P.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document
101.CAL**	XBRL Calculation Linkbase Document
101.LAB**	XBRL Label Linkbase Document
101.PRE**	XBRL Presentation Linkbase Document
101.DEF**	XBRL Definition Linkbase Document

* Filed herewith

** These interactive data files are furnished and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Act of 1934, as amended, and otherwise are not subject to liability under those sections.

\+ Indicates a management contract or compensatory plan or arrangement

(c) **Financial Statements Schedules:** All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

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, on February 24, 2021.

QEP RESOURCES, INC.
(Registrant)

/s/ Timothy J. Cutt
Timothy J. Cutt,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 24, 2021.

/s/ Timothy J. Cutt Timothy J. Cutt	President and Chief Executive Officer (Principal Executive Officer)
/s/ William J. Buese William J. Buese	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Alice B. Ley Alice B. Ley	Vice President, Controller and Chief Accounting Officer (Principal Accounting Officer)
*Mary Shafer-Malicki	Chair of the Board; Director
*Timothy J. Cutt	Director
*Phillips S. Baker, Jr.	Director
*Julie A. Dill	Director
*Joseph N. Jaggers	Director
*Michael J. Minarovic	Director
*Barth E. Whitham	Director
February 24, 2021	*By /s/ Timothy J. Cutt Timothy J. Cutt, Attorney in Fact

DESCRIPTION OF THE REGISTRANT'S SECURITIES

REGISTERED PURSUANT TO SECTION 12 OF THE

SECURITIES EXCHANGE ACT OF 1934

As of February 24, 2021, QEP Resources, Inc. has one class of securities, our common stock, par value $0.01 per share (our "common stock"), registered under Section 12 of the Securities Exchange Act of 1934, as amended.

The following description of our common stock is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to our Amended and Restated Certificate of Incorporation, dated as of May 15, 2018 (our "Certificate of Incorporation"), and our Amended and Restated Bylaws, dated as of October 27, 2020 (our "Bylaws"), each of which are incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.5 is a part. We encourage you to read our Certificate of Incorporation, our Bylaws and the applicable provisions of the General Corporation Law of the State of Delaware ("DGCL") for additional information.

Authorized Capital Shares. We are authorized to issue up to 500,000,000 shares of common stock and 10,000,000 shares of preferred stock, $0.01 par value per share.

Dividends. The holders of our common stock are entitled to receive dividends when, as and if declared by our board of directors, out of funds legally available for their payment subject to the rights of holders of any preferred stock outstanding.

Voting Rights. The holders of our common stock are entitled to one vote per share on all matters submitted to a vote of stockholders and do not have cumulative voting rights. Our board of directors is not classified and each member is elected annually. Our Bylaws provide for directors in uncontested director elections to be elected by a simple majority vote. Except as otherwise provided by the rules and regulations applicable to us or our securities, all other matters submitted to a vote of stockholders are determined by the affirmative vote of a majority of the outstanding voting power of the shares entitled to vote on the matter.

Rights Upon Liquidation. In the event of our voluntary or involuntary liquidation, dissolution or winding up, the holders of our common stock will be entitled to share equally in any of our assets available for distribution after the payment in full of all debts and distributions and after the holders of all series of outstanding preferred stock have received their liquidation preferences in full.

Listing. Our common stock is listed on The New York Stock Exchange under the trading symbol "QEP."

Miscellaneous. The outstanding shares of our common stock are fully paid and nonassessable. The holders of our common stock are not entitled to preemptive or redemption rights and our common stock has no sinking fund provision. Shares of our common stock are not convertible into shares of any other class of capital stock.

Delaware Anti-Takeover Law. We are subject to Section 203 of the DGCL, an anti-takeover law. In general, the statute prohibits a publicly held Delaware corporation from engaging in a business combination with an “interested stockholder” for a period of three years after the date of the transaction in which the person became an interested stockholder. A “business combination” includes a merger, sale of 10% or more of a corporation’s assets and certain other transactions resulting in a financial benefit to the interested stockholder. For purposes of Section 203, an “interested stockholder” is defined to include any person that is:

- the owner of 15% or more of the outstanding voting stock of the corporation;
- an affiliate or associate of the corporation and was the owner of 15% or more of the corporation’s voting stock outstanding, at any time within three years immediately before the relevant date; and
- an affiliate or associate of the persons described in the foregoing bullet points.

However, the above provisions of Section 203 do not apply if:

- the corporation’s board approves the transaction that resulted in the stockholder becoming an interested stockholder before the date of that transaction;
- after the completion of the transaction that resulted in the stockholder becoming an interested stockholder, that stockholder owned at least 85% of the corporation’s voting stock outstanding at the time the transaction commenced, excluding shares owned by the corporation’s officers and directors; or
- on or subsequent to the date of the transaction, the business combination is approved by the corporation’s board and authorized at a meeting of the corporation’s stockholders by an affirmative vote of at least two-thirds of the outstanding voting stock not owned by the interested stockholder.

Stockholders may, by adopting an amendment to the corporation’s certificate of incorporation or bylaws, elect for the corporation not to be governed by Section 203, which amendment will generally be effective 12 months after adoption. Neither our amended and restated certificate of incorporation nor our amended and restated bylaws exempts us from the restrictions imposed under Section 203. It is anticipated that the provisions of Section 203 may encourage companies interested in acquiring us to negotiate in advance with our board.

Exhibit 21.1

QEP Resources, Inc.
Subsidiaries of the Company

Name	State of Organization
QEP Energy Company[(1)]	Delaware
QEP Marketing Company, LLC[(2)]	Utah
QEP Field Services Company[(1)]	Delaware
Mustang Springs Oil Terminal, LLC[(3)]	Delaware
Permian Gathering, LLC[(3)]	Delaware
QEP Oil & Gas Company, LLC[(3)]	Delaware
Mustang Springs Water Services, LLC[(3)]	Delaware
Sakakawea Area Spill Response LLC[(4)]	Delaware

(1) 100% owned by QEP Resources, Inc.
(2) 100% owned by QEP Energy Company
(3) 100% owned by QEP Marketing Company, LLC
(4) 6% owned by QEP Energy Company

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-223553 on Form S-3 and Registration Statement No. 333-225316 on Form S-8 of our reports dated February 24, 2021, relating to the financial statements of QEP Resources, Inc. (the "Company") and the effectiveness of the Company's internal control over financial reporting appearing in this Annual Report on Form 10-K for the year ended December 31, 2020.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 24, 2021

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-223553) and Form S-8 (No. 333-225316) of QEP Resources, Inc. of our report dated February 26, 2020 relating to the financial statements, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Denver, Colorado
February 24, 2021

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

As independent petroleum engineers, we hereby consent to the reference of our appraisal reports relating to the proved gas and oil reserves of QEP Energy Company in the Annual Report on Form 10-K of QEP Resources, Inc. as of the years ended December 31, 2016, 2017, 2018, 2019, and 2020 incorporated herein by reference into Registration Statement Nos. No. 333-223553 on Form S-3 and No. 333-225316 on Form S-8.

/s/ Ryder Scott Company, L.P.
Ryder Scott Company, L.P.

Denver, Colorado
February 24, 2021

Exhibit 24

POWER OF ATTORNEY

We, the undersigned directors of QEP Resources, Inc., hereby severally constitute Timothy J. Cutt and William J. Buese, and each of them acting alone, our true and lawful attorneys, with full power to them and each of them to sign for us, and in our names in the capacities indicated below, the Annual Report on Form 10-K for 2020 and any and all amendments to be filed with the Securities and Exchange Commission by QEP Resources, Inc., hereby ratifying and confirming our signatures as they may be signed by the attorneys appointed herein to the Annual Report on Form 10-K for 2020 and any and all amendments to such Report.

Witness our hands on the respective dates set forth below.

Signature	Title	Date
/s/ Timothy J. Cutt Timothy J. Cutt	President and Chief Executive Officer Director	2/24/2021
/s/ Mary Shafer-Malicki Mary Shafer-Malicki	Chair of the Board Director	2/24/2021
/s/ Phillips S. Baker, Jr. Phillips S. Baker, Jr.	Director	2/24/2021
/s/ Julie A. Dill Julie A. Dill	Director	2/24/2021
/s/ Joseph N. Jaggers Joseph N. Jaggers	Director	2/24/2021
/s/ Michael J. Minarovic Michael J. Minarovic	Director	2/24/2021
/s/ Barth E. Whitham Barth E. Whitham	Director	2/24/2021

Exhibit 31.1

CERTIFICATION

I, Timothy J. Cutt, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2020;

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

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

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

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

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

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

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

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

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

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

February 24, 2021

/s/ Timothy J. Cutt
Timothy J. Cutt
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, William J. Buese, certify that:

1. I have reviewed this report of QEP Resources, Inc. on Form 10-K for the period ended December 31, 2020;

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

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

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

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

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

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

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

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

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

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

February 24, 2021

/s/ William J. Buese
William J. Buese
Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with this report of QEP Resources, Inc. (the Company) on Form 10-K for the period ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the Report), Timothy J. Cutt, President and Chief Executive Officer of the Company, and William J. Buese, Vice President, Chief Financial Officer and Treasurer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

QEP RESOURCES, INC.

February 24, 2021

/s/ Timothy J. Cutt
Timothy J. Cutt
President and Chief Executive Officer

February 24, 2021

/s/ William J. Buese
William J. Buese
Vice President, Chief Financial Officer and Treasurer

Exhibit 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 13, 2021

QEP Energy Company
1050 Seventeenth Street, Suite 800
Denver, Colorado 80265

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of QEP Energy Company (QEP) as of December 31, 2020. The subject properties are located in the states of North Dakota and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 13, 2021 and presented herein, was prepared for public disclosure by QEP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon and gas reserves of QEP as of December 31, 2020.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2020 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
QEP Energy Company
As of December 31, 2020

	Proved			
	Developed			
	Producing	Non-producing	Undeveloped	Total Proved
Net Reserves				
Oil/Condensate - Mbbl	96,789	4,392	136,711	237,892
Plant Products - Mbbl	31,129	887	32,070	64,086
Gas - MMcf	180,028	4,935	183,315	368,278
Income Data ($M)				
Future Gross Revenue	$ 3,727,272	$ 168,767	$ 5,243,936	$ 9,139,975
Deductions	2,282,410	91,414	3,509,059	5,882,883
Future Net Income (FNI)	$ 1,444,862	$ 77,353	$ 1,734,877	$ 3,257,092
Discounted FNI @ 10%	$ 978,946	$ 53,599	$ 655,523	$ 1,688,068

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of QEP. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, development costs, and certain abandonment costs net of salvage. Certain NGL processing fees are included as “Other” deductions as shown in the cash flow. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 97 percent and gas reserves account for the remaining 3 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income ($M) As of December 31, 2020
Discount Rate Percent	Total Proved
5	$2,260,574
9	$1,781,213
15	$1,327,587
20	$1,084,683

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission’s Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled “PETROLEUM RESERVES DEFINITIONS” is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled “PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES” in this report. The proved developed non-producing reserves included herein consist of the shut-in and behind pipe status categories.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are “estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.” All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At QEP’s request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward.” The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.”

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

QEP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which QEP owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods and analogy. Approximately 92% of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of available historical production and pressure data ending between July and December 2020, depending on the availability of data for a given case and in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by QEP and were considered sufficient for the purpose thereof. The remaining 8% of proved producing reserves were estimated by analogy where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

Approximately 85 percent of the proved developed non-producing reserves and all of the proved undeveloped reserves included herein were estimated by analogy. The remaining 15 percent of the proved developed non-producing reserves were based on the historical performance of those shut-in wells before going offline. The data utilized from the analogues and the historical performance of the shut-in wells were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

QEP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by QEP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, development costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, and base maps. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by QEP. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Historical performance trends prior to being shut-in or the initial performance of analogy wells were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by QEP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling and/or well completions, and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period.

QEP furnished us with the above mentioned average prices in effect on December 31, 2020. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, certain oil transportation fees, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by QEP. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by QEP to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$39.57/bbl	$37.30/bbl
	NGLs	WTI Cushing	$39.57/bbl	$7.12/bbl
	Gas	Henry Hub	$1.985/MMBTU	$0.89/Mcf

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by QEP and are based on the operating expense reports of QEP and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. Certain gathering and transportation costs as well as NGL processing fees are included in the operating costs. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by QEP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by QEP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties with proved reserves. At QEP's request, the abandonment costs for uneconomic wells or for other developed non-producing properties that currently do not have restoration plans are addressed separately by QEP. The estimates of the net abandonment costs furnished by QEP were accepted without independent verification.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with QEP’s plans to develop these reserves as of December 31, 2020. The implementation of QEP’s development plans as presented to us and incorporated herein is subject to the approval process adopted by QEP’s management. As the result of our inquiries during the course of preparing this report, QEP has informed us that the development activities included herein have been subjected to and received the internal approvals required by QEP’s management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to QEP. QEP has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, QEP has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2020, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by QEP were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer’s license or a registered or certified professional geoscientist’s license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to QEP. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by QEP.

QEP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, QEP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and/or S-8 of QEP of the references to our name as well as to the references to our third party report for QEP, which appears in the December 31, 2020 annual report on Form 10-K of QEP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by QEP.

We have provided QEP with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by QEP and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Stephen E. Gardner
Stephen E. Gardner, P.E.
Colorado License No. 44720
Managing Senior Vice President
[Seal]

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is a member of the Society of Petroleum Engineers and a former chairperson of the Society of Petroleum Evaluation Engineers for the Denver Chapter. He also currently serves on the latter organization's board of directors at the international level.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2020 continuing education hours, Mr. Gardner attended the annual Ryder Scott Reserves Conference, which covered a variety of reserves topics including analysis techniques for unconventional reservoirs, ESG and regulatory issues, reserves definitions and guidelines, SEC comment letter trends, and others. In addition, Mr. Gardner participated in various SPE and SPEE technical seminars, and other internal company training courses throughout the year, including one course in which he was the primary instructor, covering topics such as reserves evaluation methods and evaluation software, RTA/PTA, ethics, regulatory issues, greenhouse gas management, geothermal energy, and more.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.