QEP RESOURCES, INC.
Form 10-K
February 20, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

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

001-34778
(Commission File No.)

QEP RESOURCES, INC.
(Exact name of registrant as specified in its charter)

STATE OF 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	Name of each exchange on which registered
Common stock, $0.01 par value	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ý 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 ý

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 ý 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 (Section 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 ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 if this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. Yes ý 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	ý	Accelerated filer	o
Non-accelerated filer	o	Smaller reporting company	o
		Emerging growth company	o

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. o

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

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, 2018): $2,905,325,233.

At January 31, 2019, there were 236,366,458 shares of the registrant's $0.01 par value common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Part III is incorporated by reference from the registrant's Definitive Proxy Statement for its 2019 Annual Meeting of Stockholders to be filed, pursuant to Regulation 14A, no later than 120 days after the close of the registrant's fiscal year.

TABLE OF CONTENTS

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-focused growth and superior execution and strategies to achieve these objectives;
- our strategic objectives;
- plans to review strategic alternatives and having discussions with various parties regarding a potential transaction;
- plans to reduce general and administrative expenses significantly;
- timing of the implementation of organizational changes;
- evaluation of sale of Permian midstream assets and non-core assets;
- restructuring costs associated with contractual termination benefits;
- resolution of asserted title defects with respect to the Haynesville divestiture;
- the termination of the planned Williston Basin divestiture and not realizing the expected benefits, and the impact on our strategic initiatives;
- the effect of the strategic initiatives on employees and third parties;
- the impact of the various divestitures associated with the strategic initiatives, including production and profitability projections;
- plans to grow oil, condensate and gas production;

- 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, including the execution of our strategic initiatives;
- 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;
- the conditions impacting the timing and amount of share repurchases under our share repurchase program;
- 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 growth in production and reserves;
- evaluation of potential acquisitions, divestitures and joint venture opportunities;
- our balance sheet and sufficient liquidity providing for the ability to grow oil and condensate production;
- 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;
- focus on a sufficient liquidity position to ensure financial flexibility;
- 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;
- sufficiency of our liquidity position to ensure financial flexibility and fund our operations and capital expenditures and to achieve our strategic initiatives;
- 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;
- changes in recorded goodwill and bargain purchase gains;
- adequacy of tax accruals and potential changes to such accruals;
- redemption of senior notes
- factors impacting our ability to borrow and the interest rates offered;
- factors impacting bad debt expense;
- unrecognized tax benefits and the realization of those benefits;
- pro forma results for acquired properties;
- estimates of future liability for deficiency charges in connection with the divestiture of our assets in Pinedale (Pinedale Divestiture);
- assumptions regarding share-based compensation;

- settlement of performance share units and restricted share units in cash;
- use of net operating losses;
- alternative minimum tax credits amount and timing; and
- expected costs associated with contractual termination benefits, including severance and accelerated vesting of share-based compensation, as part of the strategic initiatives and associated divestitures.

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 Board of Directors of the Company is conducting a review of strategic alternatives;
- 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 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;
- 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;
- actions of activist shareholders; 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, loss from early extinguishment of debt and certain other items.

Argus WTI Houston An index price reflecting the weighted average price of WTI at Magellan's East Houston crude oil terminal.

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 Barrels 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 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).

cfe Cubic foot or feet of natural gas equivalents.

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.

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.

ICE Brent Brent crude oil traded on the Intercontinental Exchange, Inc. (ICE).

IFNPCR Inside FERC's Gas Market Report monthly settlement index for the Northwest Pipeline Corporation Rocky Mountains.

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 and produced water gathering systems and related commercial activities.

natural gas equivalents Oil and condensate and NGL volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil and condensate or NGL to six Mcf of natural gas.

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 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 which, 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 percentage of PUD reserves transferred to proved developed over total 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 2018
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). During 2018, the Company sold its Uinta Basin assets and entered into purchase and sale agreements to divest substantially all of its Haynesville/Cotton Valley assets in Louisiana and its Williston Basin assets in North Dakota. In January 2019, the Company closed the sale of its Haynesville/Cotton Valley assets. In February 2019, the Company announced the termination of the purchase and sale agreement related to its Williston Basin assets. 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 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".

Change in Segment Reporting due to Discontinued Operations and Termination of Marketing Agreements

In December 2014, the Company sold substantially all of its midstream business, including the Company's ownership interest in QEP Midstream Partners, LP (QEP Midstream), to Tesoro Logistics LP for total cash proceeds of approximately $2.5 billion, including $230.0 million to refinance debt at QEP Midstream, and QEP recorded a pre-tax gain of approximately $1.8 billion for the year ended December 31, 2014 (Midstream Sale). As a result of the Midstream Sale, the results of operations for the QEP Field Services Company (QEP Field Services), excluding the retained ownership of the Haynesville gathering system (Haynesville Gathering), were classified as discontinued operations in the Consolidated Financial Statements.

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing Company (QEP Marketing) and QEP Energy Company (QEP Energy). In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts were assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville Gathering. As a result, QEP Energy directly markets its own oil and condensate, gas and NGL production. While QEP continues to act as an agent for the sale of oil and condensate, gas and NGL production for other working interest owners, for whom QEP serves as the operator, QEP is no longer the first purchaser of this production. QEP has substantially reduced its marketing activities, and subsequently, is reporting lower resale revenue and expenses than it had prior to 2016.

In conjunction with the changes described above, QEP conducted a segment analysis in accordance with Accounting Standards Codification (ASC) Topic 280, Segment Reporting, and determined that QEP had one reportable segment effective January 1, 2016. The Company has recast its financial statements for historical periods to reflect the impact of the termination of marketing agreements to show its financial results without segments.

Financial and Operating Highlights

During the year ended December 31, 2018, QEP:

- Entered into a purchase and sale agreement to sell its assets in Haynesville/Cotton Valley in 2019 for an aggregate purchase price of approximately $735.0 million, subject to purchase price adjustments;
- Entered into a purchase and sale agreement to sell its assets in the Williston Basin in 2019 for a purchase price of $1,725.0 million, subject to purchase price adjustments;
- Received $243.6 million proceeds from disposition of assets in 2018, including the Uinta Basin and other non-core assets, which were used to pay down debt;
- Recognized a net realized oil price of $53.02 per bbl, a $4.80 per bbl increase compared to 2017;
- Delivered oil equivalent production of 51.9 MMboe;
- Delivered record oil and condensate production of 23.9 MMbbls, including a record 12.1 MMbbls in the Permian Basin;
- Reported year-end total proved reserves of 658.2 MMboe, including record proved crude oil and condensate reserves of 339.1 MMbbls, a 6% increase compared to 2017;
- Incurred capital expenditures (excluding property acquisitions) of $1,176.6 million, a 4% decrease over 2017;
- Repurchased and retired 6.2 million shares of the Company's outstanding common stock for $58.4 million;
- Generated a net loss of $1,011.6 million, or $4.25 per diluted share, primarily due to impairment expense of $1,560.9 million related to our Williston Basin and Uinta Basin assets; and
- Reported $974.8 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 32% increase over 2017.

Strategies

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

- operate in a safe and environmentally responsible manner;
- simplify our asset portfolio and focus on our oil basin assets;
- maintain an inventory of high return development projects in our operating areas;
- allocate capital to those projects that generate the highest returns;
- increase oil and condensate production as a percentage of total production;
- acquire businesses and assets that complement or expand our current business;
- build contiguous acreage positions that drive operating efficiencies;
- be the operator of our assets, whenever possible;
- be the low-cost driller and producer where we operate;
- actively market our production to maximize value;
- 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. QEP has an inventory of developed and identified undeveloped drilling locations primarily in the Permian Basin in western Texas and the Williston Basin in North Dakota.

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (2018 Strategic 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 sold its Uinta Basin assets in September 2018 (Uinta 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 (Planned Williston Basin Divestiture). 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, approval of buyer's shareholders and regulatory approvals. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. Following the termination of the Planned Williston Basin Divestiture, QEP will continue to operate and develop its assets in the Williston Basin, including the Company's South Antelope and Fort Berthold leaseholds. As of December 31, 2018, the Williston Basin assets were classified in the Company's Consolidated Financial Statements as held and used as the assets did not meet the held for sale criteria.

In January 2019, QEP closed its previously announced divestiture of its oil and gas assets and gathering system in the Haynesville/Cotton Valley for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments (Haynesville Divestiture). In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, all or a portion of which QEP expects to receive pursuant to the purchase and sale agreement's title dispute resolution procedures. As of December 31, 2018, the Haynesville/Cotton Valley assets were classified in the Company's Consolidated Financial Statements as held for sale.

In February 2019, QEP's Board of Directors commenced a comprehensive review of strategic alternatives to maximize shareholder value, which could result in a merger or sale of the Company or other transaction involving the Company's assets. QEP intends to engage in discussions with a variety of parties that have expressed interest in a potential transaction. Additionally, in light of the reduction of the Company's operational footprint over the last twelve months, QEP has reassessed its organizational needs and intends to significantly reduce its general and administrative expense (excluding $61.0 million of expenses associated with our 2018 Strategic Initiatives) by approximately 45% to ensure its cost structure is competitive with industry peers. The Company expects that the majority of the organizational changes will be implemented during the first half of 2019.

As part of the strategic initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 3 – Acquisitions and Divestitures, Note 8 – Restructuring Costs in Item 8 and Note 16 – Subsequent Events of Part II of this Annual Report on Form 10-K for more information.

The following map illustrates the location of the Company's significant E&P activities, the location of its Northern and Southern Regions, and related reserve and production data during the year ended December 31, 2018:

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. In addition, QEP has firm transportation commitments with interstate pipelines to move its gas volumes to multiple destinations dependent upon market conditions. Disruptions impacting pipelines or other midstream providers' 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

Southern Region

Permian Basin
QEP has 691.0 net productive 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. QEP utilizes a "tank-style" completion methodology and continues to test additional formations and evaluate the appropriate ultimate density of its development program. As of December 31, 2018, QEP had four company-operated rigs drilling in the Permian Basin. QEP has built a water infrastructure and centralized gathering infrastructure in the Permian Basin to support its tank-style development.

Haynesville/Cotton Valley
At December 31, 2018, QEP owned producing and undeveloped properties in Haynesville/Cotton Valley and additional lease rights that cover the overlying Hosston and Cotton Valley formations. QEP had 509.2 net productive wells, including its interest in non-operated wells, in Haynesville/Cotton Valley as of December 31, 2018. The Company began a refracturing program on operated wells in 2016 and continued the refracturing program throughout 2017 and 2018. In January 2019, QEP closed its previously announced divestiture of its oil and gas assets and gathering system in the Haynesville/Cotton Valley. Refer to Note 3 – Acquisitions and Divestitures and Note 16 – Subsequent Events in Item 8 of Part II of this Annual Report on Form 10-K for more information.

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 368.5 net productive wells, including its interest in non-operated wells, in the Williston Basin. QEP has developed the majority of its acreage in the Williston Basin but continues its drilling program targeting the Bakken and Three Forks formations. In addition, QEP began a refracturing program on operated wells in the Williston Basin in 2017, which continued through 2018. In November 2018, QEP entered into a purchase and sale agreement for its assets in the Williston Basin, however, the purchase and sale agreement was terminated in February 2019. Refer to Note 3 – Acquisitions and Divestitures and Note 16 – Subsequent Events in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Uinta Basin
In September 2018, QEP divested substantially all of 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, subject to post-closing purchase price adjustments. The divestiture resulted in a pre-tax loss on sale of $12.6 million, which was recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations.

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. During 2017 and 2018, QEP sold the majority of its non-core properties in this area.

Reserves

At December 31, 2018 and 2017, QEP's estimated proved reserves were approximately 658.2 MMboe and 684.7 MMboe, respectively, of which 98% were Company operated in both years. Proved developed reserves represented 35% and 37% of the Company's total proved reserves at December 31, 2018 and 2017, 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, 2018				December 31, 2017			
	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	133.6	382.3	31.5	228.9	116.0	655.5	27.9	253.1
Proved undeveloped reserves	205.5	1,105.3	39.7	429.3	204.5	1,138.1	37.3	431.6
Total proved reserves	339.1	1,487.6	71.2	658.2	320.5	1,793.6	65.2	684.7

(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, 2016, through December 31, 2018, 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)
2016	731.4	55.8	13.1
2017	684.7	43.3	15.8
2018	658.2	49.6	13.3

(1) Reserve life index is calculated by dividing year-end proved reserves by production for that year.

(2) The reserve life index for 2018 excludes 2.2 MMboe of production volumes from the Uinta Basin due to the Uinta Basin Divestiture 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.

(3) The reserve life index for 2017 excludes 9.9 MMboe of production volumes from Pinedale due to the Pinedale Divestiture in September 2017. Including production volumes from the divested Pinedale assets, the reserve life index is 12.9 years for the year ended December 31, 2017.

Proved Reserves

Proved reserve estimates and related information is presented consistent 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,					
	2018			2017		
Northern Region	(MMboe)	(% of total)		(MMboe)	(% of total)	
Williston Basin	166.8	25	%	146.9	21	%
Uinta Basin	—	—	%	100.8	15	%
Other Northern	0.3	—	%	4.5	1	%
Southern Region						
Permian Basin	307.8	47	%	272.7	40	%
Haynesville/Cotton Valley	183.3	28	%	159.8	23	%
Other Southern	—	—	%	—	—	%
Total proved reserves	658.2	100	%	684.7	100	%

QEP's total proved reserves as of December 31, 2018, decreased 26.5 MMboe from December 31, 2017, primarily due to the Uinta Basin Divestiture, which was partially offset by an increase of proved reserves as a result of extensions and discoveries in the Permian Basin and the additional acquisitions associated with the 2017 Permian Basin Acquisition (defined in Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K) during 2018. Haynesville/Cotton Valley proved reserves increased primarily due to positive performance. The Williston Basin's proved reserves increased primarily as a result of the successful refracturing program in 2018.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2018 are summarized in the table below:

	2018
	(MMboe)
Proved undeveloped reserves at January 1,	431.6
Transferred to proved developed reserves	(51.3)
Revisions to previous estimates	50.5
Extensions and discoveries	70.3
Purchase of reserves in place	9.4
Sale of reserves in place	(81.2)
Proved undeveloped reserves at December 31,	429.3

Transfers to proved developed reserves. The costs incurred for the development of PUD reserves were approximately $606.5 million, $389.3 million and $258.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

QEP's planned and actual transfers of proved undeveloped reserves to proved developed reserves results for the year ended December 31, 2018 are summarized in the table below:

	Planned Transfers to Proved Developed Reserves in 2018 as of December 31, 2017 (PUD conversions)	Actual Transfers to Proved Developed Reserves in 2018 (PUD conversions)	Difference
	(MMboe)		
Northern Region			
Williston Basin	3.1	1.4	(1.7)
Uinta Basin[1]	0.8	0.8	—
Other Northern	—	—	—
Southern Region			
Permian Basin	28.2	41.3	13.1

Haynesville/Cotton Valley	9.0	8.6	(0.4)
Other Southern	—	—	—
Total	41.1	52.1	11.0
Uinta Basin[1]	(0.8)	(0.8)	—
Total excluding the Uinta Basin	40.3	51.3	11.0

(1) Uinta Basin PUD reserve conversions in 2018 include actual activity through the closing date of the Uinta Basin Divestiture.

QEP transferred 51.3 MMboe of PUD reserves to proved developed reserves in 2018 compared to 40.3 MMboe that were planned for 2018, excluding the Uinta Basin Divestiture. QEP's PUD reserves conversion rate (the percentage of booked PUD reserves) was 12%, 10% and 18% for the years ended December 31, 2018, 2017 and 2016, respectively. At December 31, 2017, QEP's planned PUD reserve conversion rate for 2018 was 10%. QEP converted more PUD reserves than expected primarily due to drilling efficiencies and drilling more PUD locations than initially planned in the Permian Basin. QEP converted 20% of Permian Basin PUD reserves in 2018. These higher than planned PUD conversions were partially offset by a lower PUD conversion rate in the Williston Basin as we shifted more development to the refracturing program in 2018.

All of QEP's proved undeveloped reserves at December 31, 2018, are scheduled to be developed within five years from the date such locations were initially disclosed as proved undeveloped reserves. 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, 2018, QEP estimates that its future development costs relating to the development of PUD reserves are approximately $620.1 million in 2019, $882.0 million in 2020 and $1,025.1 million in 2021. 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 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 2018, our PUD reserves increased by 50.5 MMboe due to the factors summarized in the table below:

	2018 (MMboe)
Revisions due to:	
Changes in year-end prices (price impact to January 1, 2017 balance)	4.3
Positive performance	28.6
Change in development plans	32.2
Removal due to five year SEC rule	(22.6)
Other	8.0
Total revisions to prior estimates	50.5

In 2018, PUD reserves were revised upward by 50.5 MMboe primarily due to positive revisions from changes in development plans (32.2 MMboe) primarily as a result of consolidating working interests and extending lateral lengths in existing QEP operated PUD locations in the Permian Basin. The 28.6 MMboe positive performance revision is primarily from Haynesville/Cotton Valley's increased performance. These positive revisions were partially offset by 22.6 MMboe of PUD reserves that were no longer in our 2019 forecasted capital expenditure plan and will not be drilled and completed within five years of the initial date of booking of the reserves.

Extensions and Discoveries. Extensions and discoveries in 2018 were primarily in the Permian Basin and related to new well completions and associated new PUD locations.

Purchase of Reserves in Place. Purchase of reserves in place in 2018 was primarily related to the additional acquisitions associated with the 2017 Permian Basin Acquisition in 2018 as discussed in Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K.

Sale of Reserves in Place. Sale of reserves in place in 2018 was primarily related to the Uinta Basin Divestiture as discussed in Note 3 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K.

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, 2018, 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, 2018, 2017 and 2016.

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, 2018, 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 Director of Corporate Reserves. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelor's of Science degree in Engineering from the University of Minnesota. This individual has over 30 years of experience in the petroleum industry, including 15 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, 2018, 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 2018, 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, 2018 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 Director of Corporate Reserves. The Reserves Review Committee meets on a semi-annual basis, including prior to the filing of reserves estimates with the SEC and any public disclosure of reserve estimates. The Reserves Review Committee reviews data that is submitted by the Director of Corporate Reserves to RSC, including cost and pricing assumptions and reserve reconciliations from the previous reserve determinations. The Director of Corporate Reserves' 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 of Directors (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 Director of Corporate Reserves 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, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Production volumes			
Oil and condensate (Mbbl)	23,932.0	19,620.7	20,293.8
Gas (Bcf)	139.6	168.9	177.0
NGL (Mbbl)	4,661.4	5,367.3	5,978.8
Total equivalent production (Mboe)	51,857.9	53,144.9	55,780.2
Average field-level price [(1)]			
Oil (per bbl)	$59.43	$ 47.88	$ 37.90
Gas (per Mcf)	$2.82	$ 2.92	$ 2.36
NGL (per bbl)	$23.79	$ 20.85	$ 13.97
Production costs (per Boe)			
Lease operating expense	$5.07	$ 5.55	$ 4.03
Adjusted transportation and processing costs[(2)]	3.33	4.61	5.18
Production and property taxes	2.52	2.15	1.70
Total production costs	$10.92	$ 12.31	$ 10.91

(1) The average field-level price does not include the impact of settled commodity price derivatives.

(2) 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.

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

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Oil and condensate production volumes (Mbbl)					
Northern Region					
Williston Basin	11,229.5	12,353.5	14,658.6	(1,124.0)	(2,305.1)
Pinedale	—	403.8	670.9	(403.8)	(267.1)
Uinta Basin	447.3	656.8	774.2	(209.5)	(117.4)
Other Northern	93.2	114.2	141.9	(21.0)	(27.7)
Southern Region					
Permian Basin	12,137.4	6,060.9	3,983.9	6,076.5	2,077.0
Haynesville/Cotton Valley	15.6	26.5	28.4	(10.9)	(1.9)
Other Southern	9.0	5.0	35.9	4.0	(30.9)
Total production	23,932.0	19,620.7	20,293.8	4,311.3	(673.1)

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

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Gas production volumes (Bcf)					
Northern Region					
Williston Basin	15.6	15.5	15.2	0.1	0.3
Pinedale	—	51.9	82.4	(51.9)	(30.5)
Uinta Basin	10.2	16.8	22.4	(6.6)	(5.6)
Other Northern	0.9	5.7	7.9	(4.8)	(2.2)
Southern Region					
Permian Basin	10.6	6.0	5.3	4.6	0.7
Haynesville/Cotton Valley	102.2	72.9	43.4	29.3	29.5
Other Southern	0.1	0.1	0.4	—	(0.3)
Total production	139.6	168.9	177.0	(29.3)	(8.1)

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

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
NGL production volumes (Mbbl)					
Northern Region					
Williston Basin	2,495.3	3,206.1	3,182.7	(710.8)	23.4
Pinedale	—	811.0	1,417.1	(811.0)	(606.1)
Uinta Basin	99.3	152.0	203.9	(52.7)	(51.9)
Other Northern	10.5	13.4	22.3	(2.9)	(8.9)
Southern Region					
Permian Basin	2,054.4	1,168.5	1,109.9	885.9	58.6
Haynesville/Cotton Valley	0.5	16.2	28.2	(15.7)	(12.0)

Other Southern	1.4	0.1	14.7	1.3	(14.6)
Total production	4,661.4	5,367.3	5,978.8	(705.9)	(611.5)

19

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

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Total production volumes (Mboe)					
Northern Region					
Williston Basin	16,331.3	18,140.0	20,370.0	(1,808.7)	(2,230.0)
Pinedale	0.1	9,871.7	15,826.0	(9,871.6)	(5,954.3)
Uinta Basin	2,243.5	3,605.4	4,714.3	(1,361.9)	(1,108.9)
Other Northern	247.0	1,082.4	1,491.7	(835.4)	(409.3)
Southern Region					
Permian Basin	15,960.3	8,227.2	5,976.7	7,733.1	2,250.5
Haynesville/Cotton Valley	17,050.5	12,188.7	7,285.5	4,861.8	4,903.2
Other Southern	25.2	29.5	116.0	(4.3)	(86.5)
Total production	51,857.9	53,144.9	55,780.2	(1,287.0)	(2,635.3)

A regional comparison of average field-level prices and average production costs (excluding production and property taxes) per Boe is shown in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Average field-level oil price (per bbl)					
Northern Region	$62.63	$47.24	$36.97	$15.39	$10.27
Southern Region	$56.34	$49.30	$41.68	$7.04	$7.62
Average field-level oil price	$59.43	$47.88	$37.90	$11.55	$9.98
Average field-level gas price (per Mcf)					
Northern Region	$2.71	$2.93	$2.33	$(0.22)	$0.60
Southern Region	$2.84	$2.92	$2.42	$(0.08)	$0.50
Average field-level gas price	$2.82	$2.92	$2.36	$(0.10)	$0.56
Average field-level NGL price (per bbl)					
Northern Region	$23.56	$21.41	$14.50	$2.15	$6.91
Southern Region	$24.09	$18.87	$11.75	$5.22	$7.12
Average field-level NGL price	$23.79	$20.85	$13.97	$2.94	$6.88
Adjusted lease operating and transportation and processing costs (per Boe)					
Northern Region	$12.90	$11.24	$8.71	$1.66	$2.53
Southern Region	$5.82	$8.43	$10.79	$(2.61)	$(2.36)
Adjusted average lease operating and transportation and processing costs	$8.40	$10.16	$9.21	$(1.76)	$0.95

Northern Region

Williston Basin

Production volumes decreased 10% to 16,331.3 Mboe during 2018 compared to 2017, primarily as a result of reduced drilling and completion activity during 2018.

Production volumes decreased 11% to 18,140.0 Mboe during 2017 compared to 2016, primarily as a result of reduced drilling and completion activity during 2017, certain operational issues, under performance of certain wells, and producing well shut-ins associated with offset completion activity. The oil and condensate production decrease was partially offset by increased gas and NGL production, which was primarily attributable to higher allocated gas recovery as a result of restructuring a contract with a midstream provider starting in late 2016 and continuing in 2017.

During the years ended December 31, 2018, 2017 and 2016, Williston Basin production represented 31%, 34% and 37%, respectively, of QEP's total equivalent production.

Pinedale
Due to the divestiture of the Pinedale properties in September 2017, there was no production during the year ended December 31, 2018.

Production volumes decreased 38% to 9,871.7 Mboe during 2017 compared to 2016, primarily due to the divestiture of the Pinedale properties in September 2017 and reduced completion activity during the time that QEP owned the properties.

During the years ended December 31, 2017 and 2016, Pinedale production represented 19% and 28%, respectively, of QEP's total equivalent production.

Uinta Basin
Production volumes decreased 38% to 2,243.5 Mboe during 2018 compared to 2017, primarily due to the divestiture of the Uinta Basin properties in September 2018.

Production volumes decreased 24% to 3,605.4 Mboe during 2017 compared to 2016, primarily attributable to declining gas production from existing wells and reduced completion activity in 2017. QEP did not complete any wells in the Uinta Basin in 2017.

During the years ended December 31, 2018, 2017 and 2016, Uinta Basin production represented 4%, 7% and 8%, respectively, of QEP's total equivalent production.

Other Northern
Production volumes decreased 77% to 247.0 Mboe during 2018 compared to 2017, primarily due to the continued divestiture of properties during 2018.

Production volumes decreased 27% to 1,082.4 Mboe during 2017 compared to 2016, primarily due to the divestiture of properties during 2017.

During the years ended December 31, 2018, 2017 and 2016, Other Northern production represented less than 1%, 2% and 3%, respectively, of QEP's total equivalent production.

Southern Region

Permian Basin
Production volumes increased 94% to 15,960.3 Mboe during 2018 compared to 2017, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations. QEP began 2018 with six operated drilling rigs in the Permian Basin and ended 2018 with four operated drilling rigs.

Production volumes increased 38% to 8,227.2 Mboe during 2017 compared to 2016, primarily as a result of continued horizontal development activities in the Spraberry Shale and Wolfcamp formations.

During the years ended December 31, 2018, 2017 and 2016, Permian Basin production represented 31%, 15%, and 11% respectively, of QEP's total equivalent production.

Haynesville/Cotton Valley

Production volumes increased 40% to 17,050.5 Mboe during 2018 compared to 2017, due to a well refracturing program that began in 2016 and continued throughout 2017 and 2018 combined with four new well completions in 2018. The production volume increase in 2018 was partially offset by natural production decline.

Production volumes increased 67% to 12,188.7 Mboe during 2017 compared to 2016, due to a well refracturing program that began in 2016 and continued throughout 2017 combined with two new well completions in 2017. The production volume increase in 2017 was partially offset by natural production decline.

During the years ended December 31, 2018, 2017 and 2016, Haynesville/Cotton Valley's production represented 34%, 23% and 13%, respectively, of QEP's total equivalent production.

Other Southern
Production volumes decreased 15% to 25.2 Mboe during 2018 compared to 2017, due to the continued divestiture of properties.

Production volumes decreased 75% to 29.5 Mboe during 2017 compared to 2016, due to the continued divestiture of properties.

During the years ended December 31, 2018, 2017 and 2016, 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, 2018, all of which are located in the U.S.:

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Williston Basin	919	368.5	—	—	919	368.5
Uinta Basin[(1)]	—	—	—	—	—	—
Other Northern	19	3.2	33	12.2	52	15.4
Southern Region						
Permian Basin	726	691.0	—	—	726	691.0
Haynesville/Cotton Valley	1	0.1	869	509.1	870	509.2
Other Southern	1	0.4	58	3.6	59	4.0
Total productive wells	1,666	1,063.2	960	524.9	2,626	1,588.1

(1) As a result of the Uinta Basin Divestiture, QEP no longer owns operated or non-operated productive wells in the Uinta Basin as of December 31, 2018. Refer to Note 3 – Acquisitions and Divestitures in Item 8 of Part II of this Annual Report on Form 10-K for more information.

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. 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, 2018. "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
Colorado	28,295	21,201	14,953	2,453	43,248	23,654
Kansas	47,233	20,879	35,543	12,865	82,776	33,744
Louisiana	70,361	63,043	1,177	1,292	71,538	64,335
Montana	38,337	14,848	324,646	55,424	362,983	70,272
New Mexico	7,300	4,131	24,651	2,476	31,951	6,607
North Dakota	141,355	68,440	164,361	53,029	305,716	121,469
South Dakota	40	40	203,330	107,551	203,370	107,591
Texas	48,913	39,167	21,472	16,563	70,385	55,730
Utah	9,194	4,418	16,666	8,381	25,860	12,799
Wyoming	50,384	20,568	32,372	9,301	82,756	29,869
Other	15,595	4,370	157,822	43,314	173,417	47,684
Total	457,007	261,105	996,993	312,649	1,454,000	573,754

(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. 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,		
2019	2,491	587
2020	680	414
2021	480	431
2022	—	—
2023 and later	—	—
Total	3,651	1,432

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, 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	—	—	—	—	—	—
Year Ended December 31, 2017								
Northern Region								
Williston Basin	55	28.2	—	—	—	—	—	—
Pinedale	20	8.6	—	—	—	—	—	—
Uinta Basin	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Permian Basin	65	65.0	—	—	1	0.7	—	—
Haynesville/Cotton Valley	14	2.8	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	154	104.6	—	—	1	0.7	—	—
Year Ended December 31, 2016								
Northern Region								
Williston Basin	70	39.5	—	—	—	—	—	—
Pinedale	44	24.4	—	—	—	—	—	—
Uinta Basin	11	8.0	—	—	—	—	—	—
Other Northern	3	3.0	—	—	—	—	—	—
Southern Region								
Permian Basin	19	18.8	—	—	1	0.7	—	—
Haynesville/Cotton Valley	15	2.6	—	—	—	—	—	—
Other Southern	—	—	—	—	—	—	—	—
Total	162	96.3	—	—	1	0.7	—	—

The following table presents operated and non-operated wells in the process of being drilled or waiting on completion as of December 31, 2018:

		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	—	—	—	—	—	6	0.1	3	0.8
Uinta Basin	—	—	—	—	—	—	—	—	—
Other Northern	—	—	—	—	—	—	—	—	—
Southern Region									
Permian Basin[(1)]	4	13	13.0	35	35.0	—	—	—	—
Haynesville/Cotton Valley	—	—	—	—	—	1	0.0	9	0.5
Other Southern	—	—	—	—	—	—	—	—	—

(1) The number of gross operated drilling wells in the Permian Basin includes 10 wells for which surface casing has been set but as of December 31, 2018, no drilling rig was active.

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. QEP had 35 gross operated wells waiting on completion as of December 31, 2018.

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, 2018:

	Operated Put on Production		Non-operated Put on Production	
	Year Ended December 31, 2018			
	Gross	Net	Gross	Net
Northern Region				
Williston Basin	11	10.1	13	0.2
Uinta Basin	2	2.0	—	—
Other Northern	—	—	—	—
Southern Region				
Permian Basin	106	105.2	—	—
Haynesville/Cotton Valley	4	4.0	12	0.6
Other Southern	—	—	—	—

The following table presents the number of operated wells in the process of being drilled or waiting on completion at December 31, 2018 and operated wells completed and turned to sales (put on production) for the year ended December 31, 2018:

	Permian Basin		Williston Basin		Haynesville/Cotton Valley		Uinta Basin	
	December 31, 2018							
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Well Progress								
Drilling	13	13.0	—	—	—	—	—	—
At total depth - under drilling rig	8	8.0	—	—	—	—	—	—
Waiting to be completed	17	17.0	—	—	—	—	—	—
Undergoing completion	5	5.0	—	—	—	—	—	—
Completed, awaiting production	5	5.0	—	—	—	—	—	—
Waiting on completion	35	35.0	—	—	—	—	—	—
Put on production	106	105.2	11	10.1	4	4.0	2	2.0

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)
2019	16.2
Thereafter	64.9

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 our term sales commitments. If the Company's oil and condensate or gas production is not sufficient to satisfy its firm delivery commitments, the Company believes it can purchase sufficient volumes of oil and condensate or gas in the market at index-related prices to satisfy its commitments. The Company paid contractual cash obligations of $13.4 million, $40.4 million and $43.9 million for the years ended December 31, 2018, 2017 and 2016, 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 Cash Obligations and Other Commitments, 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, 2018, 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 49%, 59% and 48%, in the aggregate, of QEP's revenues for the years ended December 31, 2018, 2017 and 2016, 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, 2018	
Occidental Energy Marketing	16%
Plains Marketing LP	12%
Year Ended December 31, 2017	
Shell Trading Company	14%
Occidental Energy Marketing	13%
Andeavor Logistics LP	13%
BP Energy Company	10%
Plains Marketing LP	10%
Year Ended December 31, 2016	
Shell Trading Company	14%
BP Energy Company	10%
Valero Marketing & Supply Company	10%

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.

Employees

At December 31, 2018 and 2017, QEP had 465 and 656 employees, respectively. None of QEP's employees are represented by unions or covered by collective bargaining agreements.

Executive Officers of the Registrant

The name, age, period of service, title and business experience of each of QEP's executive officers as of February 15, 2019, are listed below:

Timothy J. Cutt	58	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).
Richard J. Doleshek	60	Executive Vice President and Chief Financial Officer (2010 to present). Treasurer (2010 to 2014). Chief Accounting Officer (2013 to 2014). Previous titles with Questar Corporation: Executive Vice President and Chief Financial Officer (2009 to 2010). Prior to joining Questar, Mr. Doleshek was Executive Vice President and Chief Financial Officer at Hilcorp Energy Company (2001 to 2009).
Christopher K. Woosley	49	Senior Vice President and General Counsel (2017 to present). 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).
Jeffery R. Tommerup	65	Senior Vice President, Eastern Region & HSE (2016 to present). Vice President, Production & HSE (2015 to 2016). Vice President, Southern Region (2009 to 2015). Previous titles with Questar: Vice President of the Southern Region (2009-2010), General Manager of Drilling Operations for the Southern Region (2008-2009), General Manager of the Uinta Division (2005-2008), Manager of Tulsa (2003-2005), Drilling Superintendent for Tulsa and Oklahoma City. Prior to joining Questar, Mr. Tommerup was Engineering Manager at Sunlight Exploration (2000-2002), served in various drilling and reservoir manager roles at Maxus Energy (1987-2000) and was a production engineer for Diamond Shamrock (1982-1987).
Joseph T. Redman	41	Vice President, Western Region (2017 to present). 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, Joe 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 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. Due to the myriad of complex federal, state, tribal and local regulations that may directly or indirectly affect QEP, 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.

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, but the 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 greenhouse gases (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.

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 (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. Environmental nongovernmental organizations (ENGOs) and certain states have challenged the Revised Waste Prevention Rule in the U.S. District Court for the Northern District of California, and industry groups have intervened in that action.

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 waters of the United States regulated under the Clean Water Act is currently entangled in ongoing litigation and related administrative matters that are not expected to be resolved for several years, and additional litigation and administrative proceedings are expected in the future. In the meantime, the EPA and the U.S. Army Corps of Engineers (Corps) are expected to determine the scope of such regulated areas much as they have over the last decade. In December 2018, the EPA and the Corps announced a revised definition that would clarify waters of the U.S. (subject to federal Clean Water Act jurisdiction) which definition does not include ephemeral streams or isolated wetlands. 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 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 nationwide permits took effect in March 2017, or when certified by each state, whichever was later. The oil and gas industry broadly utilizes nationwide permits 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 nationwide permit. Other regional and statewide general permits are available in certain states that also authorize such activities under those statutes.

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 must complete its review and make its decision regarding revision by March 2019. If the EPA chooses to revise the applicable RCRA regulations, it must sign a notice taking final action related to the new regulation by July 2021.

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 also employs additional measures, when available, to protect water quality such as using hydrocarbon free lubricants in water well construction, locking all inactive water wells to prevent unauthorized use, and transporting 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.

In the event that new or more stringent federal, state 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.

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.

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 and other agency regulations, usually for the BLM in the areas where QEP operates.

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 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's pipeline operations are 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.

Transporting Crude Oil by Rail. QEP sells crude oil to customers that may transport crude oil by rail. In May 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.

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.

North Dakota. The North Dakota Industrial Commission (NDI Commission), North Dakota's chief energy regulator, issued an order in June 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. In 2018, the NDI Commission amended its gas capture policy to provide flexibility for operators to manage their operations within the gas capture goals set by the commission.

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.

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. Elliott Management Corporation (Elliott), a beneficial holder of approximately 4.9% of our common stock (based on Elliott's Form 13F-HR filed on February 14, 2019), made a proposal to our Board on January 7, 2019, to acquire all shares of our common stock for $8.75 per share. Our Board is currently evaluating the proposal and has made the decision to engage in a process to explore strategic alternatives. Activities of activist shareholders could adversely affect our business and/or operations because:

- responding to 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 short- or long-term value from our assets;
- such activities could interfere with our ability to pursue strategic alternatives to Elliott's proposal; and
- the perceived uncertainties as to our future direction could also result in the loss of potential business opportunities, make it more difficult or costly to attract and retain qualified personnel and affect the market price and volatility of our securities.

We are exploring and evaluating strategic alternatives and there can be no assurance that we will be successful in identifying or completing any strategic alternative or that any such strategic alternative will yield additional value for our shareholders. Our Board has commenced a review of strategic alternatives to maximize shareholder value, which could result in a merger or sale of the Company or other transaction involving the Company or its assets. There can be no assurance that the exploration of strategic alternatives will result in the identification or consummation of any transaction or transactions or that any resulting plans or transactions will yield additional value for shareholders. In addition, we may incur substantial expenses associated with identifying and evaluating potential strategic alternatives. The process of exploring strategic alternatives may be time consuming and disruptive to our business operations, may impair our ability to retain and motivate key personnel and could cause third parties that deal with QEP to defer entering into contracts or making other decisions or seek to change existing business relationships. Our business, financial condition and results of operations could be adversely affected by the process. Any potential transaction would be dependent upon a number of factors that may be beyond our control, including, among other factors, market conditions, industry trends, regulatory limitations and the interest of third parties in our business.

The divestiture of our assets in the Uinta Basin and Haynesville/Cotton Valley and the termination of our Planned Williston Basin Divestiture could materially adversely affect our business, financial position, results of operations or cash flows or the prices of our securities. In September 2018, we sold our Uinta Basin assets. In November 2018, we entered into agreements to sell our Haynesville/Cotton Valley assets and our Williston Basin assets. In January 2019, we closed the sale of our Haynesville/Cotton Valley assets. In February 2019, the purchase and sale agreement related to the Planned Williston Basin Divestiture was terminated. Organizational modifications due to these transactions and our other strategic changes can alter risk and control environments; disrupt ongoing business; distract management and employees; increase expenses; result in additional liabilities, investigations and litigation; harm corporate strategy; and adversely affect results of operations. Even if these challenges are dealt with successfully, the anticipated benefits of the divestitures may not be realized. As a result of the termination of the purchase and sale agreement related to the Planned Williston Basin Divestiture, we will not realize the expected benefits of the proposed sale, and we have incurred transaction costs, including legal, accounting, financial advisory and other costs relating to the Planned Williston Basin Divestiture, a portion of which will not be reimbursed in accordance with the terms of the purchase and sale agreement. The sale of our Uinta Basin and Haynesville/Cotton Valley assets and the termination of the Planned Williston Basin Divestiture could materially adversely affect our business, financial position, results of operations and cash flows.

In addition our operations are now limited to oil producing properties located in the Permian and Williston 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; 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.

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;
- 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, including the ability of members of OPEC and Russia to maintain oil price and production controls;
- political and economic conditions and events in the United States and in or affecting other producing countries, including events in the Middle East, Africa, South America and Russia;
- the strength of the U.S. dollar relative to other currencies;
- weather conditions and natural disasters;
- domestic and international laws, regulations and taxes, including regulations or legislation relating to climate change, induced seismicity or oil and gas exploration and production activities;
- 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;
- 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 or natural gas prices would not only reduce revenue, but could also reduce the amount of oil and natural gas that we can economically produce and therefore potentially lower our oil and gas reserve quantities. In addition, the decline in oil and gas prices in the fourth quarter of 2018 and continuing volatility in the first quarter of 2019 could negatively impact our ability to execute our operating and development plans or strategic initiatives.

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;
- 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;
- reduce the amounts of QEP's estimated proved oil, gas and NGL reserves;
- reduce the carrying value of QEP's oil and gas properties due to recognizing additional impairments of proved and unproved properties;
- 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.

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 is required to perform impairment tests on its assets periodically and 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 years ended December 31, 2018, 2017 and 2016, QEP recorded impairment charges of $1,524.6 million, $38.1 million and $1,172.7 million, respectively, on its proved properties and $36.3 million, $29.0 million and $17.9 million, respectively, on its unproved properties. QEP also recorded an impairment of $6.5 million on its underground gas storage facility during the year ended December 31, 2017 and goodwill impairment of $5.3 million and $3.7 million during the years ended December 31, 2017, and 2016, respectively. 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, 2018 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 carbon pollution costs associated with climate change damages. 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.

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.

Shortages of qualified personnel and/or oilfield equipment and services could impact results of operations. 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 in the last three 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.

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:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, 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;
- 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;
- pipeline takeaway and refining and processing capacity issues; and
- title problems.

QEP could incur substantial losses as a result of 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 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.

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;
- being able to run tools and other equipment consistently through the horizontal wellbore; and
- controlling high pressure wells.

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.

The use of new horizontal drilling and completion techniques that simultaneously develop multiple producing horizons can add complexity to field development. For example, QEP experienced delays in placing certain wells in the Permian Basin into production during 2017 due to evolution of its "tank-style" completion methodology, which caused shifts in completion timing.

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, 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.

QEP has limited control over the activities on properties it does not operate, which could adversely affect our production, revenues and returns on capital. We operate 94% of our net productive oil and natural gas wells, which represents 98% of our proved developed producing reserves as of December 31, 2018. 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 materially 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.

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 and transportation. If disruption or suspension were to persist for a long period, our results of operations would be materially impacted.

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 and the commencement of production, which may cause volatility in QEP's operating results from period to period. Existing wells that offset new wells being completed by QEP or offset operators may also 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 operating results from period to period. In addition, delays in completion of wells may impact planned conversion of PUD reserves to proved developed.

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 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 arrangements, third-party systems may be temporarily unavailable due to market conditions, mechanical failures, accidents or other reasons. 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, or production shut-in, each of which could reduce profitability. Furthermore, if QEP were required to shut-in wells, it might also be obligated to pay certain demand charges for gathering and processing services, firm transportation charges on interstate pipelines 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 new 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.

Certain of QEP's undeveloped leaseholds are subject to lease agreements that will expire over the next several years unless production is established on the acreage or on units containing the acreage 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. If a lease expires or is not renewed before expiration, QEP will lose its right to develop the related reserves. While QEP seeks to actively manage its leasehold inventory by drilling sufficient wells 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.

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 2018 and 2017, QEP removed 22.6 MMboe and 8.7 MMboe, respectively, of PUD reserves that were no longer in the 2018 and 2017 forecasted capital expenditure plans, respectively, and would not be drilled and completed within five years of the initial date of booking of the reserves. At December 31, 2018, approximately 65% 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 $4.3 billion during the five years ending December 31, 2023. 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.

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 growth 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 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. Due to market conditions over the past few years, many midstream companies have attempted to renegotiate their gathering, processing and transportation agreements with their upstream counterparties. QEP has periodically been in discussions with its midstream providers. If QEP agrees to renegotiate 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 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. As of December 31, 2018, QEP's aggregate long-term contractual obligation under these agreements was $253.9 million. QEP is obligated to pay fees on minimum volumes to service providers regardless of actual volume throughput. These fees could be significant and may have a material adverse effect on QEP's results of operations.

QEP is 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. 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, provided by a group of financial institutions, to meet short-term funding needs. At year end 2018, QEP had $430.0 million of 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, 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 $2.5 billion at December 31, 2018. 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 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 covering 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. Following the closing of the Haynesville Divestiture, QEP's credit ratings were downgraded to BB- by Standard & Poor's Financial Services LLC (S&P), Ba3 by Moody's Investor Services, Inc. (Moody's) and BB- by Fitch Ratings, Inc. (Fitch). Additional 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.

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.

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 three 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.

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.

41

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 U.S. Companies in the oil and gas industry, such as QEP, are often the target of activist efforts from both individuals and 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;
- restrictions on installation or operation of gathering, processing or pipeline facilities;
- 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 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.

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.

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, such as QEP's 2017 Permian Basin Acquisition. 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 or combination 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. QEP has announced that it is evaluating the sale of certain midstream assets. 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 asset sales 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 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 (asserted or unasserted) 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.

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 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.

Clean Air Act regulations at 40 C.F.R Part 60, Subpart OOOO (Subpart OOOO) became effective in 2012, with further amendments effective in 2013 and 2014. Subpart OOOO imposes air quality controls and requirements upon QEP's operations. Additionally, in June 2016, the EPA finalized closely related rules in new Subpart OOOOa to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The new rules include, among others, new requirements for finding and repairing leaks at new well sites and "reduced emission completion" requirements for hydraulically fractured oil and gas wells. The future status of Subpart OOOOa remains uncertain given ongoing litigation and administrative regulatory actions. In September 2018, EPA announced proposed revisions to Subpart OOOOa which may reduce compliance burdens on some facilities, but the regulatory uncertainty surrounding the implementation of such revisions and the potential for legal challenges to them pose complications for QEP's 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 and the proposed revisions to such regulations.

In June 2015, the EPA and the Corps issued a new rule that expanded the scope of "waters of the United States" subject to regulation under the federal Clean Water Act. Several courts have temporarily enjoined that rule in 27 states, including Texas and North Dakota. In those states, regulated WOTUS are currently determined under the previous rules and related guidance adopted in 1986. The 2015 WOTUS rule remains in effect in the other 23 states. In December 2018, the agencies proposed a new rule that would differently revise the definition of WOTUS and replace both the 1986 and 2015 WOTUS rules. If finalized, this new definition of WOTUS will likely be challenged and sought to be enjoined in federal court. To the extent any new rule or upheld 2015 rule expands the scope of Clean Water Act regulation, the Company could face increased costs, delays and restrictions in obtaining permits for fill activities or other pollutant discharges in certain areas. The Clean Water Act and related regulations also provide for administrative, civil and criminal penalties for unauthorized discharges of fill material or oil and other pollutants and, in the event of any violation, may impose substantial costs for removal, remediation, fines and damages.

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 June 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 will require gas capture plans in the future to reduce flaring.

Additionally, in November 2016, BLM finalized the 2016 Waste Prevention Rule, which further regulates the venting, flaring and emission of natural gas on BLM and tribal leases. The 2016 Waste Prevention Rule took effect in January 2017. In September 2018, the BLM finalized the Revised Waste Prevention Rule, a rule that revised and replaced the 2016 Waste Prevention Rule, effective November 2018. 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. ENGOs and certain states have challenged the Revised Waste Prevention Rule in the U.S. District Court for the Northern District of California, and industry groups have intervened in that action. Gas capture requirements, including any similar future obligations in North Dakota or our other locations, increase our operational costs and may restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

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. Additionally, the U.S. Fish and Wildlife Service plans to issue a proposed rule listing the Lesser Prairie-Chicken as a threatened or endangered species. The Lesser Prairie-Chicken is a grouse species native to Texas, including parts of the Permian Basin where QEP operates.

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.

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. In addition, the consent or approval of the TAT will be necessary on an ongoing basis for the issuance of drilling permits and pooling/utilization clearance, and a delay in receiving any of such items could adversely affect our operations. Lessees and operators conducting operations on tribal lands are generally 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 level, some states have adopted and other states 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. 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. QEP's inability to 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 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 October 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.

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. 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 Democrat majority in the House of Representatives make it likely Congress will soon consider new legislation requiring decarbonization or use of renewable energy in much higher proportions. 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 at 40 C.F.R Part 60, Subparts OOOO and OOOOa, to include additional requirements to reduce methane and volatile organic compound emissions from oil and natural gas facilities. The status of Subpart OOOOa is uncertain given the ongoing litigation, administrative reconsideration, proposed revisions to those rules announced in September 2018, and the prospects for legal challenges to such revisions. Additionally, in June 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 December 2015, over 190 countries, including the U.S., met in Paris (COP 21) and agreed to reduce global emissions of GHG (Paris Agreement). The Paris 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 June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. Withdrawal will take a few years to implement due to the Paris Agreement's legal structure and language. The current state of development of ongoing international climate initiatives and any related domestic actions make it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or domestic regulations. Following the initiation of the U.S. withdrawal from the Paris Agreement, 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.

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. Any such legislation could also 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.

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 NOLs arising prior to the ownership change could be limited, possibly substantially. Additionally, the deductibility of any pre-ownership change disallowed interest expense carryforward amount pursuant to the Tax Cuts and Jobs Act enacted in December 2017 (Tax Legislation) limitation of the deductibility of net business interest expense, 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 NOLs, 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.

QEP relies on highly skilled personnel and, if QEP is unable to retain or motivate key personnel, hire qualified personnel, or transfer knowledge from retiring personnel, QEP's operations may be negatively impacted. QEP's performance largely depends on the talents and efforts of highly skilled individuals. QEP's future success depends on its continuing ability to identify, hire, develop, motivate, and retain highly skilled personnel for all areas of its organization. Competition in the oil and gas industry for qualified employees is intense. QEP's continued ability to compete effectively depends on its ability to attract new employees and to retain and motivate its existing employees. QEP does not maintain key-man insurance for its key management personnel. In connection with the 2018 announcement of its plans to divest its assets in the Williston Basin, the Uinta Basin and Haynesville/Cotton Valley, QEP entered into retention and severance agreements with its executives and other key management personnel. Nonetheless, the departure in January 2019 of QEP's President and Chief Executive Officer and its Executive Vice President of operations, each of whom had a long tenure with the Company, and the loss of services of one or more of QEP's key management personnel could have a negative impact on QEP's operations and financial condition.

The Company's pension plans are currently underfunded and may require large contributions, which may divert funds from other uses. QEP has a closed, qualified, defined-benefit pension plan (Pension Plan), which covers 20 active and suspended participants, or 4%, of QEP's active employees and 194 participants who are retired or were terminated and vested. Effective January 1, 2016, the Pension Plan was frozen, such that employees do not earn additional defined benefits for future services. QEP also sponsors an unfunded, nonqualified Supplemental Executive Retirement Plan (SERP). Over time, periods of declines in interest rates and pension asset values may result in a reduction in the funded status of the Company's pension plans. As of December 31, 2018 and 2017, it is estimated that QEP's pension plans were underfunded by $28.8 million and $29.5 million, respectively. The underfunded status of QEP's pension plans may require that the Company make large contributions to such plans. QEP made cash contributions of $5.7 million and $6.0 million during the years ended December 31, 2018 and 2017, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $5.5 million to these pension plans in 2019. QEP cannot, however, predict whether changing economic conditions, the future performance of assets in the plans or other factors will require the Company to make contributions in excess of its current expectations, diverting funds QEP would otherwise apply to other uses.

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 has 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.

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; and
- the inability of QEP shareholders to call special meetings or 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.

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 issues stock options, 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.

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 $100,000. The first two matters below are disclosed pursuant to that second requirement.

EPA Request for Information – In July 2015, QEP received an information request from the EPA pursuant to Section 114(a) of the Clean Air Act. The information request sought facts and data about certain tank batteries in QEP's Williston Basin operations. QEP timely responded to the information request, and has been in discussions with the EPA regarding this matter. While no formal federal enforcement action has been commenced in connection with the tank batteries to date, QEP anticipates that resolution of this matter will likely result in monetary penalties and require QEP to incur additional capital expenditures to correct non-compliance issues.

Louisiana Department of Environmental Quality Notice of Potential Penalty - In July 2010, QEP received a Notice of Potential Penalty (NOPP) from the Louisiana Department of Environmental Quality (LDEQ) regarding the assumption of ownership and operatorship of a single facility in Louisiana prior to transferring the facility's air quality permit. In 2011, QEP completed an internal audit, which identified 424 facilities in Louisiana for which QEP both failed to submit a complete permit application and to receive approval from the department prior to construction, modification, or operation. QEP has corrected and disclosed all known instances of non-compliance to the LDEQ. The LDEQ assumed lead responsibility for enforcement of the NOPP and may require the Company to pay a monetary penalty.

The Mabee Ranch Royalty Partnership, LP, et al. v. QEP Energy Company – On October 2, 2017, the Mabee Ranch Royalty Partnership, LP, John W. Mabee and Joseph Guy Mabee, Jr., surface and mineral owners of acreage in the Permian Basin in Martin and Andrews County, Texas, filed a petition in the District Court of Martin County, Texas, asserting that the Company (1) trespassed on the surface of their land by continuing surface operations following the alleged termination of certain surface use agreements and (2) breached various lease agreements by failing to correctly pay royalties and by allegedly using lease property to benefit off-lease operations. The suit alleges various tort and breach of contract claims and seeks actual money damages in excess of $1,000,000, plus interest, exemplary damages, court costs, and attorneys' fees, and a declaratory judgment that portions of the oil and gas leases covering the properties are void and no longer in effect.

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, 2019, QEP had 5,091 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.

During 2018, QEP made changes to its peer group to remove Energen Corporation and RSP Permian, Inc. as each of these entities were acquired in 2018. In addition, Callon Petroleum Company, Centennial Resource Development, Inc. and Jagged Peak Energy, Inc. were added to QEP's peer group, which is comprised of U.S. companies with similar size and scope to QEP.

QEP's previous peer group, as defined, consisted of the following companies:

Carrizo Oil & Gas, Inc.	Parsley Energy, Inc.
Cimarex Energy Company	PDC Energy, Inc.
Diamondback Energy, Inc.	Range Resources Corporation
Energen Corporation	RSP Permian, Inc.
EP Energy Corporation	SM Energy Company
Laredo Petroleum, Inc.	Southwestern Energy Company
Newfield Exploration Company	Whiting Petroleum Corporation
Oasis Petroleum Inc.	WPX Energy, Inc.

After the change in peer companies, QEP's 2018 peer group consisted of the following companies:

Callon Petroleum Company	Oasis Petroleum Inc.
Carrizo Oil & Gas, Inc.	Parsley Energy, Inc.
Centennial Resource Development, Inc.	PDC Energy, Inc.
Cimarex Energy Company	Range Resources Corporation
Diamondback Energy, Inc.	SM Energy Company
EP Energy Corporation	Southwestern Energy Company
Jagged Peak Energy, Inc.	Whiting Petroleum Corporation
Laredo Petroleum, Inc.	WPX Energy, Inc.
Newfield Exploration Company	

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 Company's old and new peer groups as of December 31, 2013, and its relative performance is tracked through December 31, 2018;
- Investment in the Company's old and new peer groups 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.

	2013	2014	2015	2016	2017	2018
QEP Resources, Inc.	$100.00	$66.15	$44.04	$60.51	$31.45	$18.50
S&P 500 Index – Total Returns	$100.00	$113.69	$115.26	$129.05	$157.22	$150.33
New Peer Group	$100.00	$68.57	$42.97	$66.21	$52.30	$31.23
Old Peer Group	$100.00	$69.99	$44.39	$68.47	$54.84	$38.12

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 (February 2018 $1.25 billion Repurchase Program). The timing and amount of any QEP share repurchases will be subject to available liquidity and market conditions. The share repurchase program does not obligate QEP to acquire any specific number of shares and may be discontinued at any time.

The following repurchases of QEP shares were made by QEP in association with vested restricted share awards withheld for taxes and pursuant to the Company's share repurchase authorization.

Period	Total shares purchased [1]	Weighted-average price paid per share	Total shares purchased as part of publicly announced plans or programs	Maximum value that may yet be purchased under the plans or programs
				(in millions)
October 1, 2018 - October 31, 2018	52,639	$ 9.79	—	1,191.6
November 1, 2018 - November 30, 2018	43,824	$ 9.08	—	1,191.6
December 1, 2018 - December 31, 2018	—	$ —	—	1,191.6
Total	96,463		—	

(1) During the three months ended December 31, 2018, QEP purchased 96,463 shares from employees 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, 2018, is provided in the table below. Our financial results for the years ended December 31, 2016, 2015, and 2014 have been recast, in accordance with GAAP, to reflect the adoption of ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost (see footnote (4) to the table below). In addition, our financial results for the year ended December 31, 2014 have been recast, in accordance with GAAP, to reflect the impact of the sale of substantially all of QEP's midstream business (see footnote (5) to 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,				
	2018[(1)]	2017[(1)]	2016[(1)]	2015	2014
Statement of Operations Data	(in millions, except per share amounts)				
Revenues[(2)(3)]	$1,932.6	$1,622.9	$1,377.1	$2,018.6	$3,293.2
Operating income (loss)[(4)]	$(1,260.4)	$101.5	$(1,600.7)	$(364.5)	$(840.3)
Income (loss) from continuing operations	$(1,011.6)	$269.3	$(1,245.0)	$(149.4)	$(409.5)
Net income from discontinued operations, net of income tax[(5)]	$—	$—	$—	$—	$1,193.9
Net income (loss)[(6)]	$(1,011.6)	$269.3	$(1,245.0)	$(149.4)	$784.4
Earnings (loss) per common share					
Basic from continuing operations[(6)]	$(4.25)	$1.12	$(5.62)	$(0.85)	$(2.28)
Basic from discontinued operations[(5)]	—	—	—	—	6.64
Basic total	$(4.25)	$1.12	$(5.62)	$(0.85)	$4.36
Diluted from continuing operations[(6)]	$(4.25)	$1.12	$(5.62)	$(0.85)	$(2.28)
Diluted from discontinued operations[(5)]	—	—	—	—	6.64
Diluted total	$(4.25)	$1.12	$(5.62)	$(0.85)	$4.36
Weighted-average common shares outstanding					
Used in basic calculation	237.9	240.6	221.7	176.6	179.8
Used in diluted calculation	237.9	240.6	221.7	176.6	179.8
Dividends per common share	$—	$—	$—	$0.08	$0.08
Balance Sheet Data					
Total Assets at December 31,	$6,117.8	$7,394.8	$7,245.4	$8,398.2	$9,256.4
Capitalization at December 31,					
Long-term debt	$2,507.1	$2,160.8	$2,020.9	$2,191.5	$2,187.7
Total equity	2,750.9	3,797.9	3,502.7	3,947.9	4,075.3
Total Capitalization	$5,258.0	$5,958.7	$5,523.6	$6,139.4	$6,263.0
Statement of Cash Flows Data					
Net cash provided by (used in) operating activities[(7)]	$816.2	$600.2	$667.2	$498.5	$1,492.2
Capital expenditures	$(1,299.7)	$(1,974.8)	$(1,208.1)	$(1,239.4)	$(2,726.4)
Net cash provided by (used in) investing activities	$(1,056.1)	$(1,168.0)	$(1,179.1)	$(1,217.6)	$578.2
Net cash provided by (used in) financing activities	$244.6	$125.8	$583.1	$(47.7)	$(990.6)
Non-GAAP Measure					
Adjusted EBITDA[(4)(8)]	$974.8	$736.1	$628.1	$1,031.2	$1,589.7

(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) Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts were assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville Gathering. As a result, QEP has substantially reduced its marketing activities, and subsequently, is reporting lower resale revenue and expenses than it had in prior periods.

(3) 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 year ended December 31, 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.

(4) In the first quarter of 2017, QEP early adopted ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which is effective retrospectively. As a result, the Company has recast operating income and Adjusted EBITDA for the years ended December 31, 2016, 2015 and 2014. The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations and all other expenses related to the Pension Plan, SERP and Medical Plan are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(5) In December 2014, QEP sold substantially all of QEP's midstream business. The results of operations of QEP's midstream business (excluding results of Haynesville Gathering) have been reflected as discontinued operations and results for the year ended December 31, 2014, have been reclassified.

(6) 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 new Tax Legislation.

(7) In the first quarter of 2018, QEP adopted ASU No. 2016-18, Statement of Cash Flows (Topic 230): Restricted cash, which is effective retrospectively. As a result, the Company has recast net cash provided by (used in) operating activities for the years ended December 31, 2017, 2016, 2015 and 2014. Refer to Note 1 – Summary of Significant Accounting Policies in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(8) Adjusted EBITDA is a non-GAAP financial measure. Management defines Adjusted EBITDA 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, loss from early extinguishment of debt and certain other items. 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.

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,				
	2018	2017	2016	2015	2014
	(in millions)				
Net income (loss)	$(1,011.6)	$269.3	$(1,245.0)	$(149.4)	$784.4
Net income from discontinued operations, net of tax	—	—	—	—	(1,193.9)
Net income (loss) from continuing operations	(1,011.6)	269.3	(1,245.0)	(149.4)	(409.5)
Interest expense	149.4	137.8	143.2	145.6	169.1
Interest and other (income) expense[(1)]	9.6	(1.6)	(23.7)	10.1	(5.8)
Income tax provision (benefit)	(317.4)	(312.2)	(708.2)	(93.6)	(232.5)
Depreciation, depletion and amortization	857.1	754.5	871.1	881.1	994.7
Unrealized (gains) losses on derivative contracts	(248.5)	(40.0)	367.0	183.7	(374.4)
Exploration expenses	0.3	22.0	1.7	2.7	9.9
Net (gain) loss from asset sales, inclusive of restructuring costs	(25.0)	(213.5)	(5.0)	(4.6)	148.6
Impairment	1,560.9	78.9	1,194.3	55.6	1,143.2
Loss from early extinguishment of debt	—	32.7	—	—	2.0
Other[(1)(2)]	—	8.2	32.7	—	—
Adjusted EBITDA from continuing operations	974.8	736.1	628.1	1,031.2	1,445.3
Adjusted EBITDA from discontinued operations	—	—	—	—	144.4
Adjusted EBITDA	$974.8	$736.1	$628.1	$1,031.2	$1,589.7

(1) In the first quarter of 2017, QEP early adopted ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which is effective retrospectively. As a result, the Company recast "Interest and other (income) expense" and "Other" for the years ended December 31, 2016, 2015 and 2014. The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations and all other expenses related to the Pension Plan, SERP and Medical Plan benefits are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2) 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 2017 Annual Report on Form 10-K filing, and analyzes the changes in the results of operations between the years ended December 31, 2018 and 2017, and between the years ended December 31, 2017 and 2016.

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). During 2018, the Company sold its Uinta Basin assets and entered into purchase and sale agreements to divest substantially all of its Haynesville/Cotton Valley assets in Louisiana and its Williston Basin assets in North Dakota. In January 2019, the Company closed the sale of its Haynesville/Cotton Valley assets. In February 2019, the Company announced the termination of the purchase and sale agreement related to its Williston Basin assets. 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".

In February 2018, QEP's Board of Directors unanimously approved certain strategic and financial initiatives (2018 Strategic 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 sold its Uinta Basin assets in September 2018 (Uinta Basin Divestiture) and closed the sale of the Haynesville/Cotton Valley assets in January 2019 (Haynesville Divestiture). In addition, the Company entered into a purchase and sale agreement for its Williston Basin assets in November 2018. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. Following the termination of the Planned Williston Basin Divestiture, QEP will continue to operate and develop its assets in the Williston Basin, including the Company's South Antelope and Fort Berthold leaseholds. See the Divestiture section below for additional discussion on the 2018 divestitures.

In February 2019, QEP's Board of Directors commenced a comprehensive review of strategic alternatives to maximize shareholder value, which could result in a merger or sale of the Company or other transaction involving the Company's assets. QEP intends to engage in discussions with a variety of parties that have expressed interest in a potential transaction. Additionally, in light of the reduction of the Company's operational footprint over the last twelve months, QEP has reassessed its organizational needs and intends to significantly reduce its general and administrative expense (excluding $61.0 million of expenses associated with our 2018 Strategic Initiatives) by approximately 45% to ensure its cost structure is competitive with industry peers. The Company expects that the majority of the organizational changes will be implemented during the first half of 2019.

As a part of the strategic initiatives, QEP has incurred or expects to incur costs associated with contractual termination benefits, including severance, accelerated vesting of share-based compensation and other expenses. Refer to Note 3 – Acquisitions and Divestitures, Note 8 – Restructuring Costs and Note 16 – Subsequent Events in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Acquisitions and Divestitures

While we believe our extensive inventory of identified drilling locations provides a solid base for growth in production and reserves, we will continue to evaluate and acquire properties in our operating areas to add additional development opportunities and facilitate the drilling of long lateral wells.

Acquisitions

During the year ended December 31, 2018, QEP closed $49.1 million of acquisitions from various entities that owned additional oil and gas interests in certain properties included in the 2017 Permian Basin Acquisition on substantially the same terms and conditions as the 2017 Permian Basin Acquisition. In addition, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage in the Permian Basin for an aggregate purchase price of $16.5 million, subject to post-closing purchase price adjustments.

In the fourth quarter of 2017, QEP acquired additional oil and gas properties in the Permian Basin for an aggregate purchase price of $721.0 million (2017 Permian Basin Acquisition). The 2017 Permian Basin Acquisition consists of approximately 15,100 acres, mainly in Martin County, Texas, which are held by production from vertical wells. QEP structured the transaction as a like-kind exchange under Section 1031 of the Internal Revenue Service Code and funded the purchase price with the proceeds from the sale of QEP's Pinedale assets. In addition to the 2017 Permian Basin Acquisition, QEP acquired various oil and gas properties, which primarily included proved and unproved leasehold acreage and additional surface acreage in the Permian Basin, for an aggregate purchase price of $94.5 million. In conjunction with these acquisitions, the Company recorded $5.3 million of goodwill, which was subsequently impaired in 2017.

In October 2016, QEP acquired oil and gas properties in the Permian Basin for an aggregate purchase price of approximately $591.0 million (2016 Permian Basin Acquisition). The 2016 Permian Basin Acquisition consisted of approximately 9,600 net acres in Martin County, Texas, which are primarily held by production from existing vertical wells. The 2016 Permian Basin Acquisition was funded with cash on hand, which included proceeds from an equity offering in June 2016. In addition to the 2016 Permian Basin Acquisition, QEP acquired various oil and gas properties, primarily in the Permian and Williston basins, for an aggregate purchase price of $54.6 million, which included additional interests in QEP operated wells and additional undeveloped leasehold acreage.

Divestitures

In January 2019, QEP closed its previously announced Haynesville Divestiture for net cash proceeds of $605.1 million, subject to post-closing purchase price adjustments. In addition, $32.2 million was placed in escrow due to title defects asserted prior to closing, all or a portion of which QEP expects to receive pursuant to the purchase and sale agreement's title dispute resolution procedures. As of December 31, 2018, the Haynesville/Cotton Valley assets were classified in the Company's Consolidated Financial Statements as held for sale. 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 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 the buyer's shareholders and regulatory approvals. In February 2019, the Company agreed with the buyer to terminate the purchase and sale agreement for its assets in the Williston Basin. As of December 31, 2018, the Williston Basin assets were classified as held and used in the Company's Consolidated Financial Statements as the assets did not meet the held for sale criteria.

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, subject to post-closing purchase price adjustments. 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 Consolidated

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. Refer to Note 1 – Summary of Significant Accounting Policies, Note 3 – Acquisitions and Divestitures and Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

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 net pre-tax gain on sale of $38.5 million related to the divestiture of properties outside our main operating areas.

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

In September 2017, QEP sold its assets in Pinedale (Pinedale Divestiture), for net cash proceeds (after purchase price adjustments) of $718.2 million. During the year ended December 31, 2018 and 2017, QEP recorded pre-tax gains on sale of $1.2 million and $180.4 million, respectively, which were recorded within "Net gain (loss) from asset sales, inclusive of restructuring costs" on the Consolidated Statements of Operations. In connection with the Pinedale Divestiture, QEP agreed to reimburse the buyer for certain deficiency charges it incurs related to gas processing and NGL transportation and fractionation contracts between the effective date of the sale and December 31, 2019, in an aggregate amount not to exceed $45.0 million. As of December 31, 2018, the remaining liability associated with estimated future payments for this commitment was $9.3 million.

In addition to the Pinedale Divestiture, during the year ended December 31, 2017, QEP received additional net cash proceeds of $88.6 million, primarily related to the sale of non-core properties in the Other Northern area.

In 2016, QEP sold its interest in certain non-core properties in the Other Southern area for aggregate proceeds of $29.0 million.

Financial and Operating Highlights

During the year ended December 31, 2018, QEP:

- Entered into a purchase and sale agreement to sell its assets in Haynesville/Cotton Valley in 2019 for an aggregate purchase price of approximately $735.0 million, subject to purchase price adjustments;
- Entered into a purchase and sale agreement to sell its assets in the Williston Basin in 2019 for a purchase price of $1,725.0 million, subject to purchase price adjustments;
- Received $243.6 million proceeds from disposition of assets in 2018, including the Uinta Basin and other non-core assets, which were used to pay down debt;
- Recognized a net realized oil price of $53.02 per bbl, a $4.80 per bbl increase compared to 2017;
- Delivered oil equivalent production of 51.9 MMboe;
- Delivered record oil and condensate production of 23.9 MMbbls, including a record 12.1 MMbbls in the Permian Basin;
- Reported year-end total proved reserves of 658.2 MMboe, including record proved crude oil and condensate reserves of 339.1 MMbbls, a 6% increase compared to 2017;
- Incurred capital expenditures (excluding property acquisitions) of $1,176.6 million, a 4% decrease over 2017;
- Repurchased and retired 6.2 million shares of the Company's outstanding common stock for $58.4 million;
- Generated a net loss of $1,011.6 million, or $4.25 per diluted share, primarily due to impairment expense of $1,560.9 million related to our Williston Basin and Uinta Basin assets; and
- Reported $974.8 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 32% increase over 2017.

Outlook

The Company continues to focus on reducing its operating costs and per well drilling costs and managing its liquidity. We believe our balance sheet and sufficient liquidity will allow us to grow oil and condensate production in our operating areas and achieve our strategic initiatives.

Based on current commodity prices, we expect to be able to fund our planned capital program for 2019 with cash flow from operating activities, cash on hand and borrowings under our credit facility. Our total capital expenditures (excluding property acquisitions), for 2019 are expected to be approximately $640.0 million, a decrease of approximately 46% from 2018 capital expenditures. We continuously evaluate our level of drilling and completion activity in light of drilling results, commodity prices 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

Our Strategic Initiatives
During 2018, we pursued our 2018 Strategic Initiatives to reposition QEP as a pure-play Permian Basin company. The Uinta Basin Divestiture and the Haynesville Divestiture have provided meaningful additional capital to the Company. The proceeds from divestitures were deployed in 2018 and early 2019 primarily to reduce debt. In February 2019, QEP agreed to terminate the purchase and sale agreement related to the Planned Williston Basin Divestiture. Organizational modifications due to these divestitures and our other strategic changes 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, we have incurred and expect to incur significant general and administrative expense, including transaction costs, retention bonuses and severance payments, in connection with the strategic initiatives. QEP producing properties are 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 such factors 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.
As a result of the termination of the purchase and sale agreement related to the Planned Williston Basin Divestiture, we will not realize the expected benefits of the proposed sale, and we have incurred transaction costs, including legal, accounting, financial advisory and other costs relating to the Planned Williston Basin Divestiture, a portion of which will not be reimbursed in accordance with the terms of the purchase and sale agreement. Since we are unable to successfully complete the Planned Williston Basin Divestiture, the price of our securities could be impacted.

Shareholder Activism
Elliott Management Corporation, is a beneficial holder of approximately 4.9% of our common stock (based on Elliott's Form 13F-HR filed on February 14, 2019). On January 7, 2019, Elliott made a proposal to our Board to acquire all shares of our common stock for $8.75 per share. Our Board is currently evaluating the proposal and has made a decision to engage in a process to explore strategic alternatives. Our business and/or operations could be adversely affected by these and any future actions of activist shareholders. Responding to actions by activist shareholders could be costly and time-consuming, disrupting our operations and diverting the attention of our management and employees. Activities of activist shareholders could interfere with our ability to execute our strategic plan or realize short- or long-term value from our assets and could interfere with our ability to pursue strategic alternatives to Elliott's proposal. Perceived uncertainties as to our future direction could also result in the loss of potential business opportunities, make it more difficult or costly to attract and retain qualified personnel and affect the trading price of our securities.

Supply, Demand, Market Risk and their Impact on Oil and Gas Prices
Oil and gas prices are affected by many factors outside of our control, including changes in supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, strength of the U.S. dollar and other factors. In recent years, oil and gas prices have been affected by supply growth, particularly in the U.S., driven by advances in drilling and completion technologies, and fluctuations in demand driven by a variety of factors.

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. Historically, field-level prices received for QEP's oil and gas production have been volatile. During the past five years, the posted price for WTI crude oil has ranged from a low of $26.19 per barrel in February 2016 to a high of $107.95 per barrel in June 2014. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. If prices of oil, gas or NGL decline to early 2016 levels or further, our operations, financial condition and level of expenditures for the development of our oil and gas reserves may be materially and adversely affected.

Global Geopolitical and Macroeconomic Factors
QEP continues to monitor the global economy, including Europe and China's economic outlook; OPEC countries' oil production and policies regarding production quotas; political unrest and global economic issues; slowing growth in certain emerging market economies; 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; 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 could have a significant impact on oil, gas and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs and 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. At December 31, 2018, after taking the divestiture of the Haynesville/Cotton Valley assets into account, QEP forecasted its 2019 annual production to be approximately 29.0 MMboe and had approximately 86% of its forecasted oil and condensate production covered with fixed-price swaps and none of its forecasted gas production covered with fixed-price swaps after the novation of gas derivatives associated with the Haynesville Divestiture. 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. The Company uses a cash flow model to assess its proved properties 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, when developing its estimate of future prices for production. All inputs for the cash flow model are evaluated at each date of estimate. 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.

We base our fair value estimates on projected financial information that we believe to be reasonably likely to occur. The signing of a purchase and sale agreement could also cause the Company to recognize an impairment of proved properties. For assets subject to a purchase and sale agreement, the terms of the 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 Planned 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. 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. In addition, the signing of a purchase and sale agreement could also cause the Company to recognize an impairment of proved properties. For assets subject to a purchase and sale agreement, the terms of the purchase and sale agreement are used as an indicator of fair value.

During the year ended December 31, 2018, the Company recorded impairments of $1,560.9 million primarily due to impairments of proved and unproved properties as a result of signing purchase and sale agreements for the Planned Williston Basin Divestiture and the Uinta Basin Divestiture. During the year ended December 31, 2017, impairments were $78.9 million primarily due to impairments of proved properties in the Other Northern area, an underground gas storage facility and unproved properties in the Permian Basin. During the year ended December 31, 2016, impairments were $1,194.3 million primarily due to impairments of proved properties in Pinedale. 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.

If forward oil prices decline from December 31, 2018 levels or we experience negative changes in estimated reserve quantities, we could have proved and unproved property 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.

Tax Legislation
The Tax Legislation enacted in December 2017 reduced our federal corporate tax rate from 35% to 21%. In addition, the Tax Legislation eliminated AMT and QEP has 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 Company currently anticipates it will realize approximately $148.4 million in AMT credit refunds over the next four years with $74.2 million to be realized in 2019 for tax year 2018, which is shown in "Income tax receivable" with the remaining $74.2 million included in "Deferred income taxes" on the Consolidated Balance Sheet as of December 31, 2018.

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 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. In certain of our producing areas, 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. As a result, multi-well pad drilling delays the completion of wells and the commencement of production. 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 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 a net loss during the year ended December 31, 2018, of $1,011.6 million, or $4.25 per diluted share, compared to net income of $269.3 million, or $1.12 per diluted share, in 2017. The increase in net loss for the year ended December 31, 2018, compared to the year ended December 31, 2017, was primarily due to an increase in impairment expense of $1,482.0 million, a $188.5 million decrease in net gain from asset sales, inclusive of restructuring costs and an increase in depreciation, depletion, and amortization expense of $102.6 million. These changes were partially offset by a $326.0 million increase in oil and condensate, gas, and NGL revenues (primarily oil and condensate revenue) and a decrease in transportation and processing costs of $127.7 million.

QEP generated net income during the year ended December 31, 2017, of $269.3 million, or $1.12 per diluted share, compared to a net loss of $1,245.0 million, or $5.62 per diluted share, in 2016. The increase in net income for the year ended December 31, 2017, compared to the year ended December 31, 2016, was primarily due to a decrease in impairment expense of $1,115.4 million, a $245.8 million (18%) increase in revenues (primarily oil and condensate revenue) and an increase of $257.5 million in realized and unrealized derivative gains. Net income during the year ended December 31, 2017 was also 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 Legislation.

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, loss 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,		
	2018	2017	2016
	(in millions)		
Net income (loss)	$(1,011.6)	$269.3	$(1,245.0)
Interest expense	149.4	137.8	143.2
Interest and other (income) expense[(1)]	9.6	(1.6)	(23.7)
Income tax provision (benefit)	(317.4)	(312.2)	(708.2)
Depreciation, depletion and amortization	857.1	754.5	871.1
Unrealized (gains) losses on derivative contracts	(248.5)	(40.0)	367.0
Exploration expenses	0.3	22.0	1.7
Net (gain) loss from asset sales, inclusive of restructuring costs	(25.0)	(213.5)	(5.0)
Impairment	1,560.9	78.9	1,194.3
Loss from early extinguishment of debt	—	32.7	—
Other[(1)(2)]	—	8.2	32.7
Adjusted EBITDA	$974.8	$736.1	$628.1

(1) In the first quarter of 2017, QEP early adopted ASU No. 2017-07, Compensation – Retirement Benefits (Topic 715): Improving the presentation of net periodic pension cost and net periodic postretirement benefit cost, which is effective retrospectively. As a result, the Company recast "Interest and other (income) expense" and "Other" for the year ended December 31, 2016. The Company recognizes service costs related to SERP and Medical Plan benefits within "General and administrative" expense on the Consolidated Statements of Operations and all other expenses related to the Pension Plan, SERP and Medical Plan benefits are recognized within "Interest and other income (expense)" on the Consolidated Statements of Operations. Refer to Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report on Form 10-K for more information.

(2)

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.

Adjusted EBITDA increased to $974.8 million during the year ended December 31, 2018, compared to $736.1 million in 2017, primarily due to an 18% increase in average realized prices, a 30% decrease in adjusted transportation and processing costs (defined below) and an 11% decrease in lease operating expense. These changes were partially offset by an 85% decrease in gas production due to the Pinedale Divestiture in late 2017 and the Uinta Basin Divestiture in late 2018, a 44% increase in general and administrative expenses and a 14% increase in production and property taxes.

Adjusted EBITDA increased to $736.1 million during the year ended December 31, 2017, compared to $628.1 million in 2016, primarily due to a 15% increase in average realized prices, a 15% decrease in transportation and processing costs and a 22% decrease in general and administrative expenses. These changes were partially offset by a 5% decrease in oil equivalent production, a 31% increase in lease operating expense and a 21% increase in production and property taxes.

Revenue

The following table presents our revenues disaggregated by revenue source.

	Year Ended December 31,			Change	
	2018	2017[1]	2016[1]	2018 vs 2017	2017 vs 2016
	(in millions)				
Oil and condensate, gas and NGL sales, as presented	$1,871.3	$1,545.3	$1,269.7	$326.0	$275.6
Transportation and processing costs in revenue[2]	55.0	—	—	55.0	—
Oil and condensate, gas and NGL sales, as adjusted[3]	$1,926.3	$1,545.3	$1,269.7	$271.0	275.6
Oil and condensate sales	$1,422.4	$939.4	$769.1	$483.0	$170.3
Gas sales	393.0	494.0	417.1	(101.0)	76.9
NGL sales	110.9	111.9	83.5	(1.0)	28.4
Oil and condensate, gas and NGL sales, as adjusted[3]	$1,926.3	$1,545.3	$1,269.7	$381.0	275.6

(1) Prior period amounts have not been adjusted under the modified retrospective method for the new revenue recognition rule. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

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

(3) 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, 2018 compared to the years ended December 31, 2017 and 2016:

	Oil and condensate	Gas	NGL	Total
Oil and condensate, gas and NGL sales, as adjusted	(in millions)			
Year ended December 31, 2016	$769.1	$417.1	$83.5	$1,269.7
Changes associated with volumes(1)	(25.5)	(18.4)	(8.5)	(52.4)
Changes associated with prices(2)	195.8	95.3	36.9	328.0
Year ended December 31, 2017	$939.4	$494.0	$111.9	$1,545.3
Changes associated with volumes(1)	206.4	(86.3)	(14.7)	105.4
Changes associated with prices(2)	276.6	(14.7)	13.7	275.6
Year ended December 31, 2018	$1,422.4	$393.0	$110.9	$1,926.3

(1) The revenue variance attributed to the change in volume is calculated by multiplying the change in volumes from the years ended December 31, 2018 and 2017, as compared to the years ended December 31, 2017 and 2016, by the average field-level price for the years ended December 31, 2017 and 2016, 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, 2018 and 2017, as compared to the years ended December 31, 2017 and 2016, by the respective volumes for the years ended December 31, 2018 and 2017, 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, is provided in the following table:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
Oil (per bbl)					
Average field-level price	$59.43	$47.88	$37.90	$11.55	$9.98
Commodity derivative impact	(6.41)	0.34	4.25	(6.75)	(3.91)
Net realized price	$53.02	$48.22	$42.15	$4.80	$6.07
Gas (per Mcf)					
Average field-level price	$2.82	$2.92	$2.36	$(0.10)	$0.56
Commodity derivative impact	(0.04)	(0.13)	0.25	0.09	(0.38)
Net realized price	$2.78	$2.79	$2.61	$(0.01)	$0.18
NGL (per bbl)					
Average field-level price	$23.79	$20.85	$13.97	$2.94	$6.88
Commodity derivative impact	—	—	—	—	—
Net realized price	$23.79	$20.85	$13.97	$2.94	$6.88
Average net equivalent price (per Boe)					
Average field-level price	$37.15	$29.08	$22.76	$8.07	$6.32
Commodity derivative impact	(3.06)	(0.29)	2.35	(2.77)	(2.64)
Net realized price	$34.09	$28.79	$25.11	$5.30	$3.68

December 31, 2018 compared to December 31, 2017

Oil and condensate sales. Oil and condensate sales were $1,422.4 million for the year ended December 31, 2018, an increase of $483.0 million, or 51%, compared to 2017. This increase was a result of a 24% increase in average field-level prices and a 22% increase in oil and condensate production volumes. The increase in average field-level oil prices was driven by an increase in average NYMEX-WTI oil prices for the comparable period, partially offset by a $2.73 per bbl, or 94% increase, in the basis differential relative to the average NYMEX-WTI oil price in 2018 compared to 2017. The 22% increase in oil and condensate production volumes was primarily driven by an increase in production in the Permian Basin due to increased drilling and completion activity, partially offset by a decrease in production in the Williston Basin due to decreased drilling activity and a loss of volumes as a result of the Pinedale Divestiture in September 2017 and the Uinta Basin Divestiture in September 2018.

Gas sales. Gas sales were $393.0 million for the year ended December 31, 2018, a decrease of $101.0 million, or 20%, compared to 2017. This decrease was a result of a 17% decrease in gas production volumes and a 3% decrease in average field-level prices. The 17% decrease in production volumes was primarily due to the Pinedale Divestiture, the Uinta Basin Divestiture and additional divestitures outside our main operating areas. These production decreases were partially offset by increases in production in Haynesville/Cotton Valley and the Permian Basin. The increase in gas production in Haynesville/Cotton Valley was due to the refracturing and drilling programs. The increase in production in the Permian Basin was due to increased drilling and completion activity, partially offset by lower gas capture rates in the Permian Basin due to midstream infrastructure construction and well connection activities in the area. The decrease in average field-level gas prices was driven by a decrease in average NYMEX-HH natural gas prices for the comparable period.

NGL sales. NGL sales were $110.9 million for the year ended December 31, 2018, a decrease of $1.0 million, or 1%, compared to 2017. This decrease was primarily a result of a 13% decrease in NGL production volumes, partially offset by a 14% increase in average field-level prices. The 13% decrease in NGL production volumes was primarily driven by the Pinedale Divestiture, declining gas volumes and lower ethane recovery in the Williston Basin and the Uinta Basin Divestiture. The 14% increase in average field-level prices was primarily driven by an increase in propane, ethane and other NGL component prices.

December 31, 2017 compared to December 31, 2016

Oil and condensate sales. Oil and condensate sales were $939.4 million for the year ended December 31, 2017, an increase of $170.3 million, or 22%, compared to 2016. This increase was a result of a 26% increase in average field-level oil prices, partially offset by a 3% decrease in oil and condensate production volumes. The increase in average field-level oil prices was driven by an increase in average NYMEX-WTI oil prices for the comparable period combined with narrowing differentials in our Northern Region properties. The 3% decrease in oil and condensate production volumes was primarily driven by a decrease in the Williston Basin due to a reduction in completion activity as well as operational issues, under performance by certain wells, and well shut-ins associated with completion activity and a decrease in Pinedale due to the Pinedale Divestiture, partially offset by an increase in the Permian Basin due to the late 2016 and 2017 acquisitions and increased completion activity.

Gas sales. Gas sales were $494.0 million for the year ended December 31, 2017, an increase of $76.9 million, or 18%, compared to 2016. This increase was a result of a 24% increase in average field-level prices, partially offset by a 5% decrease in gas production volumes. The increase in average field-level gas prices was driven by an increase in average NYMEX-HH natural gas prices for the comparable period. The 5% decrease in production volumes was primarily driven by the Pinedale Divestiture and a production decrease in the Uinta Basin due to reduced completion activity. These decreases were partially offset by increased production in Haynesville/Cotton Valley due to a well refracturing program that began in 2016 and continued throughout 2017 on QEP operated wells and two new operated well completions in 2017.

NGL sales. NGL sales were $111.9 million for the year ended December 31, 2017, an increase of $28.4 million, or 34%, compared to 2016. This increase was primarily a result of a 49% increase in average field-level prices, partially offset by a 10% decrease in NGL production volumes. The 49% increase in average field-level prices was primarily driven by an increase in propane, ethane and other NGL component prices. The 10% decrease in NGL production volumes was primarily driven by the Pinedale Divestiture and production decreases in the Uinta Basin due to lower gas volumes driven by reduced completion activity.

Resale Margin and Storage Activity

QEP purchases and resells oil and gas primarily to mitigate losses on unutilized capacity related to firm transportation commitments. The following table is a summary of QEP's financial results from its resale activities:

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(in millions)				
Purchased oil and gas sales	$48.8	$62.6	$101.2	$(13.8)	$(38.6)
Purchased oil and gas expense	(51.0)	(64.3)	(105.5)	13.3	41.2
Realized gains (losses) on gas storage derivative contracts	0.3	—	2.9	0.3	(2.9)
Resale margin	$(1.9)	$(1.7)	$(1.4)	$(0.2)	$(0.3)

Purchased oil and gas sales and expense decreased during the year ended December 31, 2018, compared to the year ended December 31, 2017, due to lower resale volumes needed to meet gas transportation commitments in the Southern Region due to increased production in the area and lower resale volumes following the sale of an underground gas storage facility in May 2018, partially offset by an increase in resale volumes to meet Northern Region gas transportation commitments retained in various divestitures.

Purchased oil and gas sales and expense decreased during the year ended December 31, 2017, compared to the year ended December 31, 2016, due to lower resale volumes, as a result of increased production in areas where the Company has oil and gas transportation commitments.

Operating Expenses

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

	Year Ended December 31,			Change	
	2018	2017	2016	2018 vs 2017	2017 vs 2016
	(in millions)				
Lease operating expense	$263.1	$294.8	$224.7	$(31.7)	$70.1
Adjusted transportation and processing costs[1]	172.6	245.3	289.2	(72.7)	(43.9)
Production and property taxes	130.8	114.3	94.8	16.5	19.5
Total production costs	$566.5	$654.4	$608.7	$(87.9)	$45.7
	(per Boe)				
Lease operating expense	$5.07	$5.55	$4.03	$(0.48)	$1.52
Adjusted transportation and processing costs[1]	3.33	4.61	5.18	(1.28)	(0.57)
Production and property taxes	2.52	2.15	1.70	0.37	0.45
Total production costs	$10.92	$12.31	$10.91	$(1.39)	$1.40

---

(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. 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	
	2018	2017[1]	2016[1]	2018 vs 2017	2017 vs 2016
	(in millions)				
Transportation and processing costs, as presented	$117.6	$245.3	$289.2	$(127.7)	$(43.9)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	55.0	—	—	55.0	—
Adjusted transportation and processing costs	$172.6	$245.3	$289.2	$(72.7)	$(43.9)
	(per Boe)				
Transportation and processing costs, as presented	$2.27	$4.61	$5.18	$(2.34)	$(0.57)
Transportation and processing costs deducted from oil and condensate, gas and NGL sales	1.06	—	—	1.06	—
Adjusted transportation and processing costs	$3.33	$4.61	$5.18	$(1.28)	$(0.57)

---

(1) Prior period amounts have not been adjusted under the modified retrospective method for the new revenue recognition rule. Refer to Note 2 – Revenue in Item 8 of Part II of this Annual Report on Form 10-K for more information.

December 31, 2018 compared to December 31, 2017

Lease operating expense (LOE). QEP's LOE decreased $31.7 million, or $0.48 per Boe, during the year ended December 31, 2018 compared to 2017. The decrease in expense was driven by the Pinedale Divestiture and the Uinta 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 addition, there was a decrease in workovers in the Williston and Permian basins and Haynesville/Cotton Valley and a decrease in water disposal and maintenance and repairs expenses in the Williston Basin. These decreases were partially offset by an increase in power and fuel, labor and maintenance and repairs expense in the Permian Basin.

Adjusted transportation and processing costs. QEP's adjusted transportation and processing costs decreased $72.7 million, or $1.28 per Boe, during the year ended December 31, 2018 compared to 2017. The decrease in expense during 2018 was primarily attributable to the Pinedale Divestiture and the Uinta Basin Divestiture. These decreases were partially offset by increased expenses in Haynesville/Cotton Valley and the Permian Basin due to increased production.

Production and property taxes. In most states in which QEP operates, QEP pays production taxes based on a percentage of field-level revenue, except in Louisiana, where severance taxes are volume based. Production and property taxes increased $16.5 million, or $0.37 per Boe, during 2018, primarily a result of increased oil and condensate revenues primarily in the Permian and Williston basins, partially offset by the Pinedale Divestiture.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $102.6 million during the year ended December 31, 2018, compared to 2017. The increase in DD&A expense was primarily due to increased production and a higher DD&A rate in the Permian Basin and Haynesville/Cotton Valley, partially offset by lower DD&A due to the Pinedale and Uinta Basin divestitures and decreased production in the Williston Basin.

Exploration expense. Exploration expense decreased $21.7 million during the year ended December 31, 2018, compared to 2017, primarily as a result of $21.3 million of exploratory well costs in 2017 related to the Central Basin Platform exploration project. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 4 – Capitalized Exploratory Well Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Impairment expense. During the year ended December 31, 2018, QEP recorded impairment charges of $1,560.9 million, compared to $78.9 million of impairment charges recorded during 2017. Of the $1,560.9 million of impairment charges recorded during 2018, $1,559.3 million related to proved and unproved properties impairment resulting from signing purchase and sale agreements for the divestitures of the Williston Basin and Uinta Basin assets. Of the $78.9 million of impairment charges recorded during 2017, $38.1 million was related to impairment of proved properties due to lower gas prices, primarily in the Other Northern area, $29.0 million was related to expiring leaseholds on unproved properties, an impairment of $6.5 million was related to an underground gas storage facility, and $5.3 million related to an impairment of goodwill.

General and administrative (G&A) expense. During 2018, G&A expense increased $68.2 million, or 44%, compared to 2017. QEP incurred $61.0 million in costs associated with the implementation of our 2018 Strategic Initiatives of which $54.3 million was related to restructuring costs. Refer to Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information on restructuring costs. In addition to the $61.0 million of costs related to our 2018 Strategic Initiatives, QEP recognized a $14.7 million increase related to reduced overhead recoveries, primarily associated with our Pinedale Divestiture, a $6.5 million increase in share-based compensation and changes in the mark-to-market value of the nonqualified, unfunded deferred compensation plan (the Wrap Plan) and an increase in labor, benefits and employee expenses. These increases were partially offset by a $5.5 million decrease in legal expenses and loss contingencies and a $2.3 million decrease in outside services expenses.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the year ended December 31, 2018, QEP recognized a gain on sale of assets of $25.0 million, compared to a gain on sale of $213.5 million during the year ended December 31, 2017. The gain on sale of assets recognized in 2018 was primarily related to a net pre-tax gain on sale of $38.5 million related to the divestiture of properties outside our main operating areas and an additional pre-tax gain on sale of $1.2 million related to the Pinedale Divestiture, partially offset by a pre-tax loss on sale of $12.6 million related to the Uinta Basin Divestiture, which included $5.4 million of restructuring costs. Refer to Note 8 – Restructuring Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information. The gain on sale of assets recognized in 2017 was primarily related to the Pinedale Divestiture, in which we recorded a pre-tax gain on sale of $180.4 million, and the sale of Other Northern properties.

December 31, 2017 compared to December 31, 2016

Lease operating expense. QEP's LOE increased $70.1 million, or $1.52 per Boe, during the year ended December 31, 2017, compared to 2016. The increase was driven by an increase in workovers in the Williston and Permian basins and Haynesville/Cotton Valley, power and fuel expenses, and services and supplies expenses in the Permian Basin and increased water disposal expenses in Haynesville/Cotton Valley. These increases were partially offset by a decrease in Pinedale due to the Pinedale 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.

Adjusted transportation and processing costs. QEP's adjusted transportation and processing costs decreased $43.9 million, or $0.57 per Boe, during the year ended December 31, 2017, compared to 2016. The decrease in expense during 2017 was primarily attributable to decreases in Pinedale, primarily related to the Pinedale Divestiture and recovery of historical transportation costs, and in Haynesville/Cotton Valley related to the recovery of fees for historical unutilized gathering and transportation capacity that was charged to QEP by the operator of wells in which QEP had a working interest. These decreases were partially offset by increased expenses in Haynesville/Cotton Valley due to increased production and the Williston Basin due to higher transportation rates.

Production and property taxes. Production and property taxes increased $19.5 million, or $0.45 per Boe, during 2017, primarily a result of increased oil and condensate and gas revenues primarily from higher field-level prices, partially offset by lower production.

Depreciation, depletion and amortization. DD&A expense decreased $116.6 million during the year ended December 31, 2017, compared to 2016. The decrease in DD&A expense was due to decreases in Pinedale, the Williston Basin and the Uinta Basin, partially offset by increases in Haynesville/Cotton Valley and the Permian Basin. The decrease in Pinedale was primarily the result of a rate decrease due to an impairment recognized in the first quarter of 2016, combined with no DD&A expense in Pinedale during the second half of 2017 as the asset was considered held for sale and sold in September 2017. The decrease in the Williston Basin was the result of decreased production, partially offset by a rate increase from decreased proved reserves. The decrease in the Uinta Basin was the result of decreased production and a rate decrease from increased proved reserves. The increases in Haynesville/Cotton Valley and the Permian Basin were primarily due to increased production.

Exploration expense. Exploration expense increased $20.3 million during the year ended December 31, 2017, compared to 2016, primarily as a result of charging $21.3 million of exploratory well costs related to the Central Basin Platform exploration project to exploration expense. During the third quarter of 2017, based on well performance and the analysis of the ultimate economic feasibility of this exploration project, QEP determined it would no longer pursue the development of the Central Basin Platform exploration project. Refer to Note 4 – Capitalized Exploratory Well Costs in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Impairment expense. During the year ended December 31, 2017, QEP recorded impairment charges of $78.9 million, compared to impairment charges of $1,194.3 million recorded during 2016. Of the $78.9 million of impairment charges recorded during 2017, $38.1 million was related to impairment of proved properties due to lower gas prices, $29.0 million was related to expiring leaseholds on unproved properties, an impairment of $6.5 million was related to an underground gas storage facility and $5.3 million related to an impairment of goodwill. Of the $38.1 million impairment on proved properties, $37.1 million related to the Other Northern area and $1.0 million related to Louisiana properties. Of the $1,194.3 million of impairment charges recorded during 2016, $1,172.7 million was related to impairment of proved properties due to lower future oil and gas prices, $17.9 million was related to expiring leaseholds on unproved properties and $3.7 million related to an impairment of goodwill. Of the $1,172.7 million impairment on proved properties, $1,164.0 million related to Pinedale properties, $4.7 million related to Uinta Basin properties, $3.4 million related to Other Northern properties and $0.6 million related to QEP's remaining Other

Southern properties.

General and administrative expense. During 2017, G&A expense decreased $43.0 million, or 22%, compared to 2016. The decrease in G&A expense in 2017 compared to 2016 was primarily due to a $27.7 million decrease in legal expenses and loss contingencies and a $19.1 million decrease in share-based compensation, primarily due to a decrease in the value of the performance share unit plan. These decreases were partially offset by an increase in labor, benefits and employee expenses.

Net gain (loss) from asset sales, inclusive of restructuring costs. During the year ended December 31, 2017, QEP recognized a gain on sale of assets of $213.5 million, compared to a gain on sale of $5.0 million during the year ended December 31, 2016. The gain on sale of assets recognized in 2017 was primarily related to the Pinedale Divestiture, in which we recorded a pre-tax gain on sale of $180.4 million, and the sale of Other Northern properties. The gain on sale of assets recognized in 2016 was primarily due to the continued divestitures of properties in the Other Southern area.

Non-Operating Expenses

December 31, 2018 compared to December 31, 2017

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, 2018, gains on commodity derivative instruments were $90.4 million, of which $254.4 million were unrealized gains on derivative contracts related to production and storage contracts, $5.9 million were unrealized losses on derivative contracts related to the Uinta Basin Divestiture and $158.1 million were realized losses. During 2017, gains on commodity derivative instruments were $24.5 million, of which $69.9 million were unrealized gains on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture and $15.5 million were realized losses. Refer to Note 7 – Derivative Contracts 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) decreased $11.2 million during the year ended December 31, 2018, compared to 2017. The decrease was primarily related to a $4.0 million loss on the Wrap Plan, an increased loss on sale of inventory of $3.3 million, an increase in pension expense of $2.7 million and a $1.3 million decrease in interest income due to lower average balances on commercial paper.

Loss from early extinguishment of debt. Loss from early extinguishment of debt decreased $32.7 million during the year ended December 31, 2018, compared to 2017. The 2017 loss was the result of the early repayment of senior notes during the year ended December 31, 2017. Refer to Note 9 – Debt in Item 8 of Part II of this Annual Report on Form 10-K for more information.

Interest expense. Interest expense increased $11.6 million, or 8%, during the year ended December 31, 2018, compared to 2017. The increase during the year ended December 31, 2018, was primarily related to increased interest on borrowings under the credit facility, partially offset by lower aggregate average interest rates on our senior notes.

Income tax (provision) benefit. Income tax benefit increased $5.2 million during the year ended December 31, 2018, compared to 2017. The increase in income tax benefit was the result of increased net loss before income taxes, partially offset by the federal rate change from 35% to 21% as a result of the federal tax reform and change in state income tax, which resulted in a combined effective federal and state income tax rate of 23.9% during the year ended December 31, 2018, compared to 727.7% for the year ended December 31, 2017.

December 31, 2017 compared to December 31, 2016

Realized and unrealized gains (losses) on derivative contracts. During the year ended December 31, 2017, gains on commodity derivative instruments were $24.5 million, of which $69.9 million were unrealized gains on derivative contracts related to production and storage contracts, $29.9 million were unrealized losses related to the Pinedale Divestiture (refer to Note 7 – Derivative Contracts in Item 8 of Part II of this Annual Report on Form 10-K for more information) and $15.5 million were realized losses. During 2016, losses on commodity derivative instruments were $233.0 million, of which $367.0 million were unrealized losses, partially offset by $134.0 million of realized gains.