QEP RESOURCES, INC.
Form 10-K
February 24, 2016

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, 2015
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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes ý No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	ý		Accelerated filer	o
Non-accelerated filer	o	(Do not check if a smaller reporting company)	Smaller reporting company	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, 2015): $3,270,110,187.

At January 31, 2016, there were 176,756,832 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 2016 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.

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Where You Can Find More Information

QEP Resources, Inc. (QEP or the Company) files annual, quarterly, and current reports with the U.S. Securities and Exchange Commission (SEC). These reports and other information can be read and copied at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549-0213. Please call the SEC at 800-732-0330 for further information on the operation of the Public Reference Room. The SEC also maintains an Internet site at http://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 contains copies of charters for various board committees, including the Audit Committee, Corporate Governance Guidelines and QEP's Business Ethics and Compliance Policy.

Finally, 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).

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:

- our growth strategies;
- strong liquidity position providing financial flexibility;
- geographical diversity;
- our liquidity and sufficiency of cash flow from operations, cash-on-hand and availability under our credit facility to fund our planned capital expenditures, operating expenses, repayment of maturing debt and payment of dividends;
- ability to deliver growth by focusing on our exploration and production assets;
- our continued evaluation of, and ability to pursue, acquisition opportunities;
- our inventory of drilling locations;
- drilling and completion plans;
- focus on improving operating performance by optimizing reservoir development, enhancing well completion designs and aggressively pursuing cost reductions;
- results from planned drilling operations and production operations;
- plans to reduce drilling and completion activities, slow production growth and preserve liquidity;
- exports of oil from the U.S.;
- payment of dividends;

- estimates of reserves and development of proved undeveloped (PUD) reserves;
- leasehold development and financial capability to continue planned development;
- plans to recover or reject ethane from produced natural gas;
- impact of lower or higher commodity prices and interest rates;
- volatility of gas, oil and NGL prices and factors impacting such prices;
- impact of global geopolitical and macroeconomic events;
- plans to enter into derivative contracts and the anticipated benefits from our derivative contracts;
- pro forma results for acquired properties;
- divestitures of non-core assets;
- any potential repurchases of our senior notes;

- amount and allocation of forecasted capital expenditures and plans for funding capital expenditures, operating expenses and development costs;
- resale revenues and expenses;
- adequacy of insurance;
- timing and impact of proposed environmental legislation and studies;
- impact of governmental regulations;
- assumptions regarding equity compensation;
- settlement of performance share units in cash;
- recognition of compensation costs related to equity compensation grants;
- expected contributions to our employee benefit plans;
- employee benefit plan gains or losses;
- the importance of Adjusted EBITDA (a non-GAAP financial measure) as a measure of performance;
- delays caused by transportation, processing, storage and refining capacity issues;
- fair values and critical accounting estimates, including estimated asset retirement obligations;
- uncertain tax benefits;
- implementation and impact of new accounting pronouncements;
- impact of shutting in wells;
- factors impacting our ability to transport oil and gas;
- potential for asset impairments and impact of impairments on financial statements;
- impact of the sale of our midstream business;
- the estimated costs of closing our Tulsa office;
- the impact of the loss of a significant customer or nonpayment of a counterparty;
- ability to meet delivery and sales commitments;
- value of pension plan assets;
- impact of our charter and bylaws on a potential takeover;
- inflation and deflation;
- unrecognized tax benefits;
- asset retirement obligations; and
- changes to production plans, operating costs and capital expenditures.

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;
- changes in gas, oil and NGL prices;
- global geopolitical and macroeconomic factors;
- general economic conditions, including the performance of financial markets and interest rates;
- asset impairments;
- liquidity constraints, including those resulting from the cost and availability of debt and equity financing;
- drilling methods and results;
- shortages of oilfield equipment, services and personnel;
- lack of available pipeline, processing and refining capacity;
- our ability to successfully integrate acquired assets;
- 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 laws or regulations;
- legislation regarding climate change and other initiatives related to drilling and completion techniques, including hydraulic fracturing and water use;
- derivative activities;
- volatility in the commodity-futures market;
- failure of internal controls and procedures;
- failure of our information technology infrastructure or applications;
- 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 volumes;
- 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
- 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, and certain other non-cash and/or non-recurring items.

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-only swap A derivative that "swaps" the basis (defined above) between two sales points from a floating price to a fixed price for a specified commodity volume over a specified time period. A basis-only swap is typically used to fix the price relationship between a geographic sales point and a NYMEX reference price.

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.

developed reserves Reserves of any category that can be 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. See 17 C.F.R. Section 210.4-10(a)(6).

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. See 17 C.F.R. Section 210.4-10(a)(9).

dry hole A well drilled and abandoned and found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed expenses and taxes.

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. See 17 C.F.R. Section 210.4-10(a)(13).

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.

LIBOR London Interbank Offered Rate (LIBOR) is the interest rate that banks charge each other for one-month, three-month, six-month and one-year loans.

M Thousand.

MM Million.

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 NGL volumes are converted to natural gas equivalents using the ratio of one barrel of crude oil, condensate or NGL to 6,000 cubic feet 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 Resources Inc.'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.

possible reserves Those additional reserves that are less certain to be recovered than probable reserves. See 17 C.F.R Section 210.4-10(a)(17).

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. See 17 C.F.R. Section 210.4-10(a)(18).

proved properties Properties with proved reserves. See 17 C.F.R. Section 210.4-10(a)(23).

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. See 17 C.F.R. Section 210.4-10(a)(22).

proved undeveloped reserves or PUD Proved 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. See 17 C.F.R. Section 210.4-10(a)(31).

reserves Estimated remaining quantities of natural gas, crude oil 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. See 17 C.F.R. Section 210.4-10(a)(26).

reservoir A porous and permeable 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. See 17 C.F.R. Section 210.4-10(a)(27).

resource play Refers to regionally distributed oil and natural gas accumulation as opposed to conventional plays which are more limited in their 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 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 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.

T Trillion.

undeveloped reserves Reserves of any category 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. See 17 C.F.R. Section 210.4-10(a)(31).

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 2015
PART I
ITEM 1. BUSINESS

Nature of Business

QEP Resources, Inc. (QEP or the Company) is a holding company with two principal subsidiaries, QEP Energy Company and QEP Marketing Company, which are engaged in two primary lines of business: (i) oil and gas exploration and production (QEP Energy) and (ii) oil and gas marketing, operation of a gas gathering system and an underground gas storage facility and corporate activities (QEP Marketing and Other). See Part II, Item 8 – Financial Statements and Supplementary Data, Note 14 – Operations by Line of Business, of the Notes to the Consolidated Financial Statements for financial information relating to our segments.

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. As a result, QEP Energy will market its own gas, oil and NGL production. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts have been assigned to QEP Energy, except those contracts related to natural gas storage activities and the Haynesville gathering system (Haynesville Gathering). The change in affiliate transactions will simplify our business processes and financial statements by eliminating the majority of intercompany transactions.

QEP's operations are focused in two geographic regions: the Northern Region (primarily in Wyoming, North Dakota and Utah) and the Southern Region (primarily in Texas and Louisiana) of the United States. QEP's corporate headquarters are located in Denver, Colorado.

Discontinued Operations

On December 2, 2014, the Company closed the sale of substantially all of its midstream business, including its 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 QEP Field Services Company (QEP Field Services) reporting segment, excluding the retained ownership of Haynesville Gathering, was classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the Consolidated Financial Statements. For reporting purposes, Haynesville Gathering has been added to the QEP Marketing and Other segment.

Financial and Operating Highlights

Our financial and operating highlights for 2015 are as follows:

- Achieved record equivalent production of 326.8 Bcfe, a 1% increase over 2014;
- Increased oil production to 19.6 MMbbls, a 14% increase over 2014, including 76% growth in the Permian Basin and 13% growth in the Williston Basin;
- Increased natural gas production to 181.1 Bcf, including record production in Pinedale;
- Generated a net loss of $149.4 million, or $0.85 per diluted share;
- Generated $1,029.3 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), of which $1,027.1 million was contributed by QEP Energy;
- Incurred capital expenditures (excluding property acquisitions) of $1,011.9 million, a 41% reduction from 2014;
- Reduced general and administrative expenses by $23.3 million, or 11%;

- Received field-level prices that were 42% lower than in 2014, however, our commodity derivative contracts offset 19% of this decrease; and
- Maintained $376.1 million in cash and cash equivalents and had no borrowings under our revolving credit facility.

Strategies

We create value for our shareholders through returns-focused growth, superior execution and a low-cost structure. To achieve these objectives we strive to:

- operate in a safe and environmentally responsible manner;
- allocate capital to those projects that generate the highest returns;
- acquire businesses and assets that complement or expand our current business;

- maintain a sustainable, diverse inventory of low-cost, high-margin resource plays;
- develop the highest-potential areas of the resource plays in which we operate;
- build contiguous acreage positions that drive operating efficiencies;
- be the operator of our assets, whenever possible;
- be the low-cost driller and producer in each area where we operate;
- actively market our production to maximize value;
- utilize derivative contracts to mitigate the impact of gas, oil or NGL price volatility and to lock in acceptable cash flows required to support future capital expenditures;
- attract and retain the best people; and
- maintain a capital structure that provides us the necessary financial flexibility with which to invest in organic growth and potential acquisition opportunities, as they may arise.

In response to the current commodity price environment, we have reduced drilling and completion activities, slowed production growth, reduced costs and preserved our liquidity. We plan to continue these strategies in 2016. We have reduced the number of QEP operated drilling rigs to nine as of December 31, 2015, compared to a high of 21 during 2014. We have reduced our annual capital expenditure budget (excluding property acquisitions) significantly for 2016 to approximately $475.0 million from approximately $1.0 billion in 2015. We are focused on driving improved operating performance by optimizing reservoir development, enhancing well completion designs and aggressively pursuing cost reductions.

On December 2, 2014, QEP completed the Midstream Sale; see "Discontinued Operations" above. QEP believes this transaction represented a significant milestone in the strategic repositioning of the Company, as it has better positioned the Company to focus on its exploration and production assets.

Exploration and Production – QEP Energy

QEP Energy conducts exploration and production (E&P) activities in several of North America's most important hydrocarbon resource plays. QEP Energy has an inventory of identified development drilling locations in the Pinedale Anticline in western Wyoming, the Williston Basin in North Dakota, the Uinta Basin in eastern Utah, the Permian Basin in western Texas, the Haynesville/Cotton Valley in northwestern Louisiana, and other proven properties in Wyoming, Utah and Colorado. In recent years, QEP sold substantially all of its properties within its Midcontinent area in the Southern Region, which is located in the Anadarko Basin in Oklahoma and Texas.

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $941.8 million (the Permian Basin Acquisition). The acquired properties consisted of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 270 vertical producing wells in the Permian Basin. The Permian Basin Acquisition created a new core area of operations for QEP Energy.

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 as of December 31, 2015:

QEP Energy generated approximately $1,027.1 million, $1,437.0 million, and $1,301.8 million of the Company's Adjusted EBITDA from continuing operations during the years ended December 31, 2015, 2014 and 2013, respectively (refer to Item 7 of Part II of this Annual Report on Form 10-K for management's definition and a reconciliation to net income of this non-GAAP financial measure). During 2015, QEP Energy operated in two regions – the Northern Region (including the states of Wyoming, North Dakota, Utah and Colorado) and the Southern Region (including the states of Texas and Louisiana). The Northern Region contributed 78% of 2015 production, while the Southern Region contributed 22%. QEP Energy reported 3,620.2 Bcfe of estimated proved reserves as of December 31, 2015, down 311.7 Bcfe from 2014. Of those estimated proved reserves, approximately 79%, or 2,844.0 Bcfe, were located in the Northern Region at December 31, 2015, compared to 77%, or 3,026.0 Bcfe, at December 31, 2014. The remaining 21%, or 776.2 Bcfe, were located in the Southern Region at December 31, 2015, compared to 23%, or 905.9 Bcfe, at December 31, 2014. Approximately 58% of the total proved reserves reported by QEP Energy at December 31, 2015, were developed and approximately 42% of the total proved reserves were comprised of oil and NGL, up from 41% at December 31, 2014.

QEP Energy faces competition in every facet of its business, including the acquisition of producing leaseholds, wells and undeveloped leaseholds, the marketing of oil and gas, and the procurement of goods, services and labor. Its longer-term growth strategy depends, in part, on its ability to acquire reasonably valued acreage containing undeveloped reserves and identify and develop the reserves in a responsible, low-cost and efficient manner.

QEP Energy seeks to acquire, develop and produce oil and gas from resource plays in its core operating areas and expand into new areas where it can capitalize on its operating expertise. Since the existence and distribution of hydrocarbons in resource plays is now better understood, developing these accumulations generally has lower risk than developing conventional discrete hydrocarbon accumulations. Resource plays typically require drilling many wells at high density to fully develop and recover the hydrocarbon accumulations. QEP Energy's resource play development requires expertise in drilling a large number of complex, highly deviated or horizontal wells to true vertical depths, which generally range between 10,000 and 14,000 feet, and the application of advanced well completion techniques, including hydraulic fracture stimulation, to achieve economic production rates and recoverable volumes. QEP Energy also conducts exploratory drilling to determine the commercial viability of its unproven leasehold inventory. For 2016, QEP plans to allocate approximately $475.0 million of its capital budget to E&P activities. QEP Energy seeks to maintain geographical and geological diversity with its two regions. The Company may pursue additional acquisitions of producing properties through the purchase of assets or corporate entities in order to further expand its presence in its core areas of operations or to create new core areas.

QEP Energy sells its gas, oil and NGL production to a variety of customers, including gas-marketing firms, industrial users, local-distribution companies, crude oil refiners and marketers. QEP Energy regularly evaluates counterparty credit risk and may require financial guarantees or prepayments from parties that fail to meet its credit criteria.

Energy Marketing — QEP Marketing and Other

QEP Marketing provides wholesale marketing and sales of affiliate and third-party gas, oil and NGL. The reporting segment QEP Marketing and Other generated $2.2 million, $1.3 million and $14.2 million of the Company's Adjusted EBITDA from continuing operations (refer to Item 7 of Part II of this Annual Report on Form 10-K for management's definition and a reconciliation to net income of this non-GAAP financial measure) for each of the years ended December 31, 2015, 2014 and 2013, respectively. As a wholesale marketing entity, QEP Marketing concentrates on markets in the Rocky Mountains and Haynesville that are either close to affiliate reserves and production or accessible by major pipelines. QEP Marketing contracts for firm-transportation capacity on pipelines and firm-storage capacity at Clay Basin, a large gas storage facility in northeast Utah.

QEP Marketing, through its wholly owned subsidiary Clear Creek Storage Company, LLC (Clear Creek), owns and operates an underground gas storage reservoir in southwestern Wyoming. QEP Marketing uses owned and leased storage capacity together with firm-transportation capacity to manage seasonal swings in prices in the Rocky Mountain region. QEP Marketing also sells NGL volumes associated with the gas stored in its Clear Creek storage facility. In addition, QEP Marketing owns a membership interest in Haynesville Gathering, located in Louisiana. Haynesville Gathering includes 200 miles of gas gathering facilities with approximate throughput capacity of 2,000 MMcf/d and a treating facility with throughput capacity of 600 MMcf/d and primarily provides services to QEP Energy.

QEP Marketing competes directly with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. QEP Marketing also competes with brokerage houses, energy hedge funds and other energy-based companies offering similar services. QEP Marketing sells gas volumes to wholesale marketers, industrial users and utilities. QEP Marketing sells oil volumes to refiners, marketers and other companies, including some with pipeline facilities near QEP Energy's producing properties. In the event pipeline facilities are not available, QEP Marketing arranges transportation of oil by truck or rail to storage, refining or pipeline facilities.

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. While QEP believes that it is in compliance, in all material respects, with currently applicable laws and regulations and has not experienced any material adverse effect arising from these requirements, there is no assurance that this trend will continue in the future. Due to the myriad of complex federal, state, tribal and local regulations that may affect QEP, directly or indirectly, 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 exploration and production 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 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. The Environmental Protection Agency (EPA) has adopted or proposed to adopt various regulations governing air quality standards and controls, source determination and permitting requirements, and methane emissions. The EPA is considering adopting more stringent air permitting and other air quality regulations specific to oil and gas exploration, production, gathering and processing that go beyond the requirements of existing federal regulations.

Additionally, many states have adopted, or are considering 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.

Greenhouse Gases Regulations and Climate Change Legislation. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases (GHG) endanger public health and the environment because such emissions are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings, the EPA has adopted and substantially expanded regulations for the measurement and annual reporting of 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 in recent years 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 and/or regional GHG cap and trade programs.

Bureau of Land Management Methane Regulations. In January 2016, the Department of Interior's Bureau of Land Management (BLM) announced a proposed rule dealing with venting and flaring of oil and natural gas, leak detection, storage tanks, pneumatic controllers and pumps, well maintenance and unloading, drilling and completions, and royalties for oil and gas facilities producing on federal and tribal lands. The proposed rule was published in the Federal Register in February 2016. QEP is evaluating the economic implications of complying with this rule, but the rule could potentially lead to QEP plugging and abandoning some of its existing oil and gas wells on federal and tribal lands and the loss of certain unproduced oil and gas reserves.

Clean Water Act and Safe Drinking Water Act. The Clean Water Act and similar state laws regulate discharges of wastewater, oil, fill material and pollutants into waters of the United States. 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 Safe Drinking Water Act (SDWA) and comparable state statutes restrict the disposal, treatment, and release of water produced or used during oil and gas development.

In May 2015, the EPA and the Army Corps of Engineers issued a pre-publication final rule defining the jurisdictional "waters of the United States" regulated under the Clean Water Act. The final rule, which has been stayed pending the outcome of litigation, could change the scope of waters subject to federal jurisdiction under the Clean Water Act.

Oil Pollution Act of 1990. The 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 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. A person responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances released into the environment and for damages to natural resources. Frequently, third parties file claims for personal injury and property damage allegedly caused by the hazardous substances into the environment.

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 on 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." It is possible, however, that certain exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. Any repeal or modification of the 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.

Hydraulic Fracturing Regulations. All wells drilled in tight sand or shale reservoirs require hydraulic fracture stimulation to achieve economic production rates and recoverable reserves. The majority of 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 does not use diesel fuel in any of its fracturing operations. 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, 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 possible 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 additional information) and those generally associated with oil and gas drilling and production operations, such as the risk of spills, releases, discharges, accidents and injuries to persons and property.

Currently, all well construction activities, including hydraulic fracture stimulation, are regulated by state agencies that review and approve all aspects of oil and gas well design, construction, and operation. The EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and is considering other potential regulation of hydraulic fracturing activities, including pretreatment standards for the oil and gas extraction industry, reporting and disclosure requirements for chemical substances and mixtures used for hydraulic fracturing, and other potential regulations to address the effects of hydraulic fracturing on drinking water. Additionally, in March 2015, the BLM finalized new regulations, to become effective in June 2015, regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal land. The new regulations have the potential to increase the cost of drilling and completing any well requiring federal permits, and could result in further delays in getting such permits to authorize drilling and completion activities on federal and tribal lands. Several states, including some in which QEP operates, have filed suit against the Department of Interior over the final BLM hydraulic fracturing regulations, and as a result the effective date of the regulations has been indefinitely stayed pending the outcome of the litigation.

Legislation has also been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process, notwithstanding the proposed and ongoing rulemaking proceedings and voluntary disclosures to FracFocus noted above. At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. 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 where QEP Energy operates. These regulations include, but are not limited to, such matters as lease provisions, drilling and production requirements, surface use restrictions, environmental standards and royalty considerations. Recently, the BIA published final regulations (effective in March 2016) significantly altering 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-ways for operation on tribal lands.

Endangered Species Act, National Environmental Policy Act. 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. Many of QEP's operations are subject to the requirements of the National Environmental Policy Act (NEPA), and are therefore evaluated under NEPA for their direct, indirect and cumulative environmental impacts. This 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. The Emergency Planning and Community Right-to-Know Act (EPCRA) requires certain facilities to disseminate information on chemical inventories to employees as well as local emergency planning committees and emergency response departments. In October 2015, the EPA indicated its intent to commence a rulemaking to add natural gas processing facilities to the list of facilities that must report under EPCRA; however, it also declined to extend EPCRA to cover other types of facilities in the oil and gas sector. The federal Occupational Safety and Health Act establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communication programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

Regulation of Transportation and Sales of Natural Gas

Natural Gas Act of 1938, Natural Gas Policy Act of 1978 and Energy Policy Act of 2005. The FERC regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938 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.

Regulation of Underground Storage

QEP, through its wholly owned subsidiary Clear Creek, operates an underground gas storage facility under the jurisdiction of the FERC. The FERC establishes rates for the storage of natural gas. The FERC also regulates, among other things, the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment.

State Regulations

North Dakota. The North Dakota Industrial Commission (the 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 addition, the Commission has 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 will be imposed on certain wells that cannot meet the capture goals. Based on its production forecasts and midstream agreements, QEP believes it is and will continue to be in compliance with this order from the Commission.

On December 9, 2014, the Commission issued Commission Order No. 25417 requiring that crude oil produced in the Bakken Petroleum System be conditioned to remove lighter, volatile hydrocarbons to reduce the vapor pressure of crude oil. The Commission's order was effective April 1, 2015. QEP believes it is currently in compliance with this new order from the Commission.

Other Regulations

Transporting Crude Oil by Rail. The U.S. Department of Transportation has started rulemaking to develop new requirements for shipping crude oil by rail. In May 2015, the U.S. Department of Transportation issued its 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.

Dodd-Frank Wall Street Reform and Consumer Protection Act. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) is designed to provide a comprehensive framework for the regulation of the over-the-counter derivatives market with the intent to provide greater transparency and reduction of risk between counterparties. The Dodd-Frank Act subjects swap dealers and major swap participants to capital and margin requirements and requires many derivative transactions to be cleared on exchanges. The Dodd-Frank Act provides for an exemption from these clearing and cash collateral requirements for commercial end-users. See Part I, Item 1A - Risk Factors, in this Annual Report on Form 10-K for more information.

Seasonality

QEP drills and completes wells throughout the year, but adverse weather conditions can impact drilling and field operations. In the Pinedale field, QEP typically ceases completion activities on newly drilled wells due to adverse weather conditions in the fourth quarter and resumes completion activity in the first quarter as weather allows.

Significant Customers

QEP's five largest customers accounted for 30%, 33%, and 38%, in the aggregate, of QEP's revenues for the years ended December 31, 2015, 2014 and 2013, respectively. 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. During the year ended December 31, 2015, no customer accounted for 10% or more of QEP's total revenues. During the year ended December 31, 2014, Valero Marketing and Supply Company accounted for 10% of the Company's total revenues. During the year ended December 31, 2013, Freepoint Commodities, LLC accounted for 13% of the Company's total revenues.

Employees

At December 31, 2015, QEP had 693 employees compared to 765 employees at December 31, 2014. 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 January 31, 2016, are listed below:

Charles B. Stanley	57	Chairman (2012 to present). President and Chief Executive Officer (2010 to present). Previous titles with Questar Corporation: Chief Operating Officer (2008 to 2010); Executive Vice President and Director (2003 to 2010); President, Chief Executive Officer and Director, Market Resources and Market Resources subsidiaries (2002 to 2010).
Richard J. Doleshek	57	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, Hilcorp Energy Company (2001 to 2009).
Jim E. Torgerson	52	Executive Vice President (2013 to Present). Senior Vice President - Operations (2012 to 2013). Senior Vice President, Drilling and Completions (2011 to 2012). Previous titles with Questar Corporation: Vice President, Drilling and Completions (2009 to 2010); Vice President, Rockies Drilling and Completions (2005 to 2008).
Austin S. Murr	62	Senior Vice President - Business Development (2012 to present). Vice President - Land and Business Development (2010 - 2012). Previous titles with Questar Corporation: Vice President - Land and Business Development (2006 - 2010); Director of Business Development (2004 to 2006).
Christopher K. Woosley	46	Vice President, General Counsel and Corporate Secretary (January 2016 to present). Vice President and General Counsel (2012 to 2016). 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).
Margo D. Fiala	52	Vice President - Human Resources (2010 to present). Prior to joining QEP, Ms. Fiala held a variety of roles at Suncor Energy (1995 to 2010), including Director of Human Resources.
Matthew T. Thompson	43	Vice President - Energy (2015 to present). Vice President - Northern Region (2013 to 2015). General Manager - High Plains Division (2012 to 2013). General Manager - Legacy Division (2011 to 2012). Reservoir Engineer Manager (2010 to 2011). Previous Titles with Questar Corporation: Manager - Business Development (2009 to 2010). Director of Planning (2006 to 2009).
Alice B. Ley	42	Vice President, Controller and Chief Accounting Officer (2014 to present). Interim Controller (2013-2014). Director of Financial Reporting (2012 to 2013). Prior to joining QEP, Ms. Ley was an Accounting/Financial Analyst Manager at Frontier Oil Corporation (2001 to 2011) and an Audit Manager in the Energy Division of Arthur Anderson, LLP (1996 to 2001).

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.

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.

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

- changes in domestic and foreign supply and demand of gas, oil and NGL;
- the potential long-term impact of an abundance of gas, oil and NGL from unconventional sources on the global and local energy supply;
- changes in local, regional, national and global demand for gas, oil, NGL and related commodities;

- the level of imports and/or exports of, and the price of, foreign gas, oil 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 conditions;
- 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), including the ability of members of OPEC to agree to and maintain oil price and production controls and the ability of Iran to market its oil following the lifting of trade sanctions;
- political and economic conditions and events in the United States and in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the strength of the U.S. dollar;
- weather conditions and natural disasters;
- government regulations and taxes, including regulations or legislation relating to climate change 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 fuels, including coal, nuclear energy and biofuels;
- demand for electricity as well as natural gas used as fuel for electricity generation;
- the level of global gas, oil and NGL inventories and exploration and production activity; and
- the quality of oil and gas produced.

QEP's revenues, operating income and future rate of growth depend heavily on the prices QEP receives for the crude oil and natural gas it produces and sells. Prices also affect the amount of cash QEP has available for capital expenditures, its ability to repay debt, borrow money or raise additional capital, the amount and value of its proved reserves and the price of QEP's common stock. In response to lower commodity prices, QEP reduced its 2015 capital expenditures by approximately 59% in 2015 and plans to reduce its 2016 capital expenditures as compared to 2015 by over 50%. In 2015, QEP also reduced drilling and completion activities, slowed production growth, reduced costs and preserved its liquidity. QEP plans to continue these strategies in 2016. In February 2016, in response to the current commodity price environment, the Board of Directors indefinitely suspended the payment of quarterly dividends. If market prices for gas, oil and NGL continue to decline, QEP may elect to curtail production, further reduce operation costs and capital expenditures and discontinue certain exploration and development programs. QEP may be unable to decrease its costs in an amount sufficient to offset reductions in revenues from lower commodity prices and may incur losses.

Lower gas, oil and NGL prices or negative adjustments to gas, oil and NGL reserves may result in significant impairment charges. Lower commodity prices, such as those experienced recently, may not only decrease QEP's revenues, operating income and cash flows but also may reduce the amount of gas, oil 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 it 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, 2015, 2014 and 2013, QEP recorded impairment charges of $39.3 million, $1,041.4 million and $1.2 million, respectively, on its proved properties and $2.0 million, $101.8 million and $32.3 million, respectively, on its unproved properties. QEP also recorded goodwill impairment of $14.3 million and $59.5 million during the years ended December 31, 2015 and December 31, 2013, respectively. Forward prices in mid February 2016 have declined subsequent to the test for impairment at December 31, 2015. If forward prices remain at mid February 2016 levels, we have approximately $1.8

billion of proved property net book value, as of December 31, 2015, primarily associated with our Pinedale field, 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. Additionally, a further decrease from mid February levels in forward gas, oil or NGL prices could result in additional properties being at risk for impairment. If QEP records a significant impairment, the financial covenants under its revolving credit facility may limit the amount of debt that QEP is able to incur. See Part I, Item 8, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K for additional information.

Slower U.S. and global economic growth rates may continue to materially adversely impact QEP's operating results. The U.S. and other economies are still recovering from the global financial crisis of 2008 and the recession that followed. Growth has been modest and at an unsteady rate. More volatility may occur before a sustainable growth rate is achieved. Historically, global economic growth drives demand for energy from all sources, including fossil fuels. If future economic growth rates, particularly in China, the U.S. and Europe, are lower, excluding changes in other factors, demand for QEP's gas, oil and NGL production will likely decrease, resulting in further decreases in commodity prices and reductions to QEP's revenues, cash flows from operations and its profitability.

The Company may not be able to economically find and develop new reserves. The Company's profitability depends not only on prevailing prices for gas, oil 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 and geological interpretation and judgment. Reserve estimates are imprecise and will change as additional 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 properties, 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 percent per year. 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.

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, and increasing prices for, oilfield equipment, services and qualified personnel could impact results of operations. Although it is not currently an issue, if the prices of oil and gas increase, 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, can increase accordingly, creating challenges and causing periodic shortages. In periods of high prices, there have also been regional shortages of drilling rigs and other equipment. Any cost increases associated with a recovery of prices could impact profit margin, cash flow and operating results or restrict the 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. There are operational risks associated with the exploration, production, gathering, transporting, and storage of gas, oil and NGL, including:

- injuries and/or deaths of employees, supplier personnel, or other individuals;
- fire, explosions and blowouts;

- aging infrastructure and mechanical problems;
- unexpected drilling conditions, including abnormally pressured formations or loss of drilling fluid circulation;
- pipe, cement or casing failures;
- title problems;
- equipment malfunctions and/or mechanical failure;
- security breaches, cyberattacks, piracy, or terrorist acts;
- theft or vandalism of oilfield equipment and supplies, especially in areas of increased activity;
- severe weather;
- plant, pipeline, railway and other facility accidents and failures;
- truck and rail loading and unloading; and
- 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.

QEP could incur substantial losses as a result of injury or loss of life, pollution or other environmental damage, damage to or destruction of property and 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 the operator and 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 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 for property damage suffered by the contractor.

As is also customary in the oil and gas industry, QEP maintains insurance against some, but not all, of these potential risks and losses. 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.

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:

- 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.

If our drilling and completion results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Multi-well pad drilling may result in volatility in QEP operating results. QEP utilizes multi-well pad drilling where practical. 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 completion process. As a result, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s quarterly operating results.

Lack of availability of refining, gas processing, storage, gathering or transportation capacity will likely impact results of operations. The lack of availability of satisfactory gas, oil and NGL gathering and transportation, including trucks, railways and pipelines, gas processing, storage or refining capacity may hinder QEP's access to gas, oil 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. If transportation quality requirements change, QEP might be required to install or contract for additional treating or processing equipment, 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 leasehold assets are subject to lease agreements that will expire over the next several years unless production is established on units containing the acreage. Leases on oil and gas properties typically have a 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. If QEP's leases expire and QEP is unable to renew the leases, 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.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be classified as proved reserves if they are from wells scheduled to be drilled within five years after the date of booking. Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. QEP cannot be certain that development will occur as scheduled. QEP may be required to write down its PUD reserves if it does not drill wells within the required five-year time frame.

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 specifically identified and scheduled certain well locations as an estimation of its future multi-year drilling activities on its existing acreage. 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 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 QEP 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.

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, 2015, QEP's aggregate long-term contractual obligation under these agreements was $807.7 million. QEP is obligated to pay fees on minimum volumes to service providers regardless of actual volume throughput. These fees could be significant and 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 obtain needed 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 the Company 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 gas, oil 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. QEP has no borrowings under its revolving unsecured revolving credit facility. In the past, QEP has utilized its revolving credit facility, provided by a group of financial institutions, to meet short-term funding needs. Borrowings under its revolving credit facility incur floating interest rates. From time to time, the Company may use interest rate derivatives to manage the interest rate on a portion of its floating-rate debt. The interest rates for the Company's revolving credit facility are tied to QEP's ratio of indebtedness to Consolidated EBITDAX (as defined in the credit agreement). 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 its results of operations.

QEP's debt and other financial commitments may limit its financial and operating flexibility. QEP's total debt was approximately $2.2 billion at December 31, 2015. QEP also has various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. 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, 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 to payments on its debt or to comply with any restrictive terms of its debt. Additionally, the credit 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 restrictions on QEP's ability to dispose of assets, make certain investments, incur liens and additional debt, and engage in transactions with affiliates. If the current commodity price environment continues and QEP continues to reduce 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 and may not be in compliance with the financial covenants in its revolving credit agreement in the future. Refer to 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.

A downgrade in QEP's credit rating could negatively impact QEP's cost of and access to capital. On February 10, 2016, Standard & Poor’s Financial Services LLC (S&P) reaffirmed QEP’s credit rating of BB+ but changed its outlook from stable to negative. On February 12, 2016, Moody’s Investor Services, Inc. (Moody’s) downgraded QEP’s credit rating from Ba1 to B1. QEP's credit ratings may be subject to future downgrades. The downgrade by Moody’s triggered an additional financial covenant under QEP’s credit agreement, which could limit the amount of debt that QEP may incur. The downgrade of its credit rating may make it more difficult or expensive for QEP to raise capital from financial institutions or other sources. In addition, a further downgrade could require QEP to provide financial assurance of its performance under certain contractual arrangements and derivative agreements.

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, and occasional sales of non-core assets. Future cash flows from operations are subject to a number of variables, such as the level of production from existing wells, prices of gas, oil 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 gas, oil and NGL prices, and to protect cash flow and returns on capital from downward commodity price movements. To the extent the Company enters into commodity derivative transactions, it may forgo some or all of the benefits of commodity price increases. Additional financial regulations may change QEP's reporting and margin requirements relating to such instruments. 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 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. 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, which are heightened in periods of low commodity prices, 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 financial guarantees or prepayments, have been obtained from some but not all counterparties. Nonperformance by a trade creditor or joint venture partner could result in financial losses. In addition, QEP's commodity derivative transactions expose it to risk of financial loss if the counterparty fails to perform under a contract. During periods of falling commodity prices, QEP's commodity derivative receivable positions increase, which increases its counterparty credit exposure. QEP monitors creditworthiness of its trade creditors, joint venture partners, derivative counterparties and financial institutions on an ongoing basis. However, if one of them were to experience a sudden change in liquidity, it could impair such a party's ability to perform under the terms of QEP's contracts. QEP is unable to predict sudden changes in creditworthiness or ability of these parties to perform and could incur significant financial losses.

QEP 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 non-governmental organizations 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, environmental activists continue to advocate for increased regulations on 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 production or gathering facilities;
- more stringent setback requirements from houses, schools and businesses;
- towns, cities, states and counties considering 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;
- increased severance and/or other taxes;
- cyberattacks;
- legal challenges or lawsuits;
- negative publicity about QEP;
- 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; and
- postponement of federal and state oil and gas lease sales.

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 and could have a material adverse effect on its business, financial condition and results of operations.

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, exploitation, 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 equity funds 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;
- marketing its gas, oil 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 business.

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 current business, such as QEP's Permian Basin Acquisition completed in February 2014. 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:

- difficulty integrating the operations, systems, management and other personnel and technology of the acquired business 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 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 agreements 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 agreements also limit QEP’s ability to incur certain indebtedness, which could indirectly limit QEP’s ability to engage in acquisitions of businesses.

QEP may be unable to dispose of non-core, non-strategic assets on financially attractive terms, resulting in reduced cash proceeds. QEP's business strategy also includes sales of non-core, non-strategic assets. QEP continually evaluates its portfolio of assets related to capital investments, divestitures and joint venture opportunities. Various factors can materially affect QEP's ability to dispose of assets on terms acceptable to QEP. Such factors include current commodity prices, laws, regulations and the permitting process impacting oil and gas operations in the areas where the assets are located, willingness of the purchaser to assume certain liabilities such as asset retirement obligations, QEP's willingness to indemnify buyers for certain matters, and other factors. Inability to achieve a desired price for assets, or underestimation of amounts of retained liabilities or indemnification obligations, can result in a reduction of cash proceeds, a loss on sale due to an excess of the asset's net book value over proceeds, or liabilities that must be settled in the future at amounts that are higher than QEP had expected.

QEP is involved in legal proceedings that may result in substantial liabilities. Like many oil and gas companies, QEP is involved in various legal proceedings, such as title, royalty, and contractual disputes, in the ordinary course of its business. The cost to settle legal proceedings or satisfy any resulting judgment against QEP in such proceedings could result in a substantial liability, which could materially and adversely impact QEP's cash flows and operating results for a particular period. Current accruals for such liabilities may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal proceedings could change from one period to the next and such changes could be material.

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.

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. The 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.

For example, in May 2015, the EPA and the Army Corps of Engineers issued a pre-publication final rule defining the jurisdictional “waters of the United States” regulated under the Clean Water Act. The final rule, which has been stayed pending the outcome of litigation, could increase the scope of waters subject to federal jurisdiction under the Clean Water Act.

Also, new 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 and is undergoing further reconsideration by the EPA, which may result in more stringent air quality controls and requirements for QEP’s operations. For example, in September 2015, the EPA published proposed updates to Subpart OOOO to achieve additional methane and volatile organic compound reductions from certain activities in the oil and gas industry. The proposed rule would include, among others, new requirements for finding and repairing leaks at new well sites and reduced emission completion requirements for oil wells. 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.

In October 2015, the EPA announced its final ruling to lower the existing 75 parts per billion (ppb) National Ambient Air Quality Standard (NAAQS) for ozone under the federal Clean Air Act to 70 ppb. A lowered ozone NAAQS could result in a significant expansion of ozone nonattainment across the United States, including areas in which QEP operates. Oil and natural gas operation in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

In September 2015, the EPA published a proposed rule under the Clean Air Act regarding source determination and permitting requirements for the onshore oil and gas industry. The proposed rule seeks public comment on two approaches for defining the term "adjacent", which is one of three factors used to determine whether oil and gas equipment and activities at multiple locations may be considered part of a single source that is subject to permitting requirements under the Clean Air Act. Depending on the EPA's final approach, the oil and gas industry could be subject to increased air quality permitting costs and more stringent control requirements and enhanced reporting requirements and costs.

In September 2015, the EPA also issued a proposed FIP to implement the Federal Minor New Source Review Program in Indian Country for oil and gas production. The proposed FIP may apply to QEP's operations on the Fort Berthold Reservation in the Williston Basin and on the Uintah and Ouray Indian Reservations in the Uinta Basin. The proposed FIP would incorporate emission limits and other requirements for various federal air quality standards, applying them to a range of equipment and processes used in oil and gas production. The FIP may also lead to the EPA imposing reservation-specific regulations on the Uintah and Ouray Indian reservations in Utah, requiring controls on existing equipment in the area due to ozone readings above the NAAQS standard in several previous years. The proposals will likely have increased controls and compliance costs.

The FERC has jurisdiction over the operation of QEP Marketing's Clear Creek underground gas storage facility by virtue of the facility's connection to interstate pipelines (also subject to FERC jurisdiction) at both its inlet and outlet. Clear Creek is subject to specific FERC regulations governing interstate transmission facilities and activities, including but not limited to rates charged for transmission, open access/non-discrimination, and public disclosure via an electronic bulletin board of daily capacity and flows.

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, 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 North Dakota Industrial 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 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 will be imposed on certain wells that cannot meet the capture goals. The BLM has proposed a new rule related to further controls on the venting and flaring of natural gas on BLM land. The proposed rule has been finalized and is out for public comment. These capture requirements, and any similar future obligations in North Dakota or our other locations, may increase our operational costs or restrict our production, which could materially and adversely affect our financial condition, results of operations and cash flows.

New rules regarding crude oil shipments by rail may pose unique hazards that may have an adverse effect on our operations. In December 2014, the North Dakota Industrial Commission issued Commission Order No. 25417 requiring that crude oil produced in the Bakken Petroleum System be conditioned to remove lighter, volatile hydrocarbons to improve the marketability and safe transportation of the crude oil. The Commission’s order was effective April 1, 2015. In May 2015, the U.S. Department of Transportation issued its 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. 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 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 in areas where we operate as threatened or endangered 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.

Current federal regulations restrict activities during certain times of the year on significant portions of QEP leasehold due to wildlife activity and/or habitat. QEP has worked with federal and state officials in Wyoming to obtain authorization for limited winter drilling activities on the Pinedale Anticline and has developed measures, such as drilling multiple wells from a single pad location, to minimize the impact of its activities on wildlife and wildlife habitat in its operations on federal lands. Many of QEP's operations are subject to the requirements of NEPA, and are therefore evaluated under NEPA for their direct, indirect and cumulative environmental impacts. This is done in Environmental Assessments or Environmental Impact Statements prepared for a lead agency under Council on Environmental Quality and other agency regulations, usually for the BLM in the areas where QEP operates currently. In September 2008, the BLM issued a Record of Decision (ROD) on the Final Supplemental Environmental Impact Statement (FSEIS) for long-term development of gas resources in the Pinedale Anticline Project Area (PAPA). Under the ROD, QEP is allowed to drill and complete wells year-round in one of five Concentrated Development Areas.

As a result of future legislation, certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated and our production may be subject to the imposition of new U.S. federal taxes. The U.S. President's Fiscal Year 2017 Budget Proposal and legislation introduced in a prior session of Congress includes proposals that, if enacted into law, would eliminate certain key U.S. federal income tax provisions currently available to oil and gas exploration and production companies or potentially make our operations subject to the imposition of new U.S. federal taxes. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, (iv) an extension of the amortization period for certain geological and geophysical expenditures and (v) imposition of a $10.25 per barrel fee on oil, to be paid by oil companies (but the budget does not describe where and how such a fee would be collected). It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change, as well as any changes to or the imposition of new U.S. federal, state or local taxes (including the imposition of, or increase in production, severance or similar taxes), could increase the cost of exploration and development of oil and gas resources, which would negatively affect our financial condition and results of operations.

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 Clean Air Act, the Clean Water Act, the 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 environmental groups to oppose drilling on some of QEP's federal and state leases. These groups sometimes sue federal and state regulatory agencies and/or the Company under these laws for alleged 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. For example, QEP's operations on tribal lands within the Williston Basin in North Dakota and Vermillion Basin in Wyoming continue to be delayed due to the substantial backlog of permit applications and backlog of environmental reviews. 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 recently published final regulations (effective in March 2016) significantly altering 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-ways for QEP’s operations on tribal 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 all aspects of oil and gas well design and operation. The EPA recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the SDWA and issued guidance related to this newly asserted regulatory authority. The EPA appears to be considering its existing regulatory authorities for possible avenues to further regulate hydraulic fracturing fluids and/or the components of those fluids. Additionally, in May 2012, the BLM proposed new regulations regarding chemical disclosure requirements and other regulations specific to well stimulation activities, including hydraulic fracturing, on federal and tribal lands and proposed further revision to those regulations in May 2013. The BLM finalized those regulations in March 2015, to become effective in June 2015; however, due to pending litigation (discussed below), the effective date of the rule has been postponed. The new regulations have the potential to increase the cost of drilling and completing any well requiring federal permits, and could result in further delays in getting such permits to authorize drilling and completion activities on federal and tribal lands. Several states, including some in which the Company operates, have filed suit against the Department of Interior over the final BLM hydraulic fracturing regulations, which could contribute to increased uncertainty regarding the Company’s compliance obligations on federal and tribal lands and has caused the effective date of the regulations to be postponed.

Legislation has also been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process, notwithstanding the proposed and ongoing rulemaking proceedings noted above. At the state level, some states have adopted and other states are considering adopting regulations that could restrict hydraulic fracturing in certain circumstances. 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.

The EPA is also considering other potential regulation of hydraulic fracturing activities. For example, in April 2015, the EPA published proposed pretreatment standards for the oil and gas extraction industry. The proposed regulations would address discharges of wastewater pollutants from onshore unconventional oil and gas extraction facilities to publicly owned treatment works. The EPA is also collecting information as part of a nationwide study into the effects of hydraulic fracturing on drinking water. In June 2015, the EPA released a draft assessment of the potential impacts to drinking water resources from hydraulic fracturing for public comment and peer review. The results of this study, which has not been finalized, could result in additional regulations, which could lead to operational burdens similar to those described above. The EPA has also issued an advance notice of proposed rulemaking and initiated a public participation process under the Toxic Substances Control Act (TSCA) to seek comment on the information that should be reported or disclosed for hydraulic fracturing chemical substances and mixtures and the mechanisms for obtaining this information. Additionally, in January 2015, several national environmental advocacy groups filed a lawsuit requesting that the EPA add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" under the Toxics Release Inventory (TRI) program of the Emergency Planning and Community Right-to-Know Act. The EPA responded to the groups’ request in October 2015 granting the petition in part as it related to natural gas processing facilities, and denying the petition as to all other types of facilities in the oil and gas sector.

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 initiatives and 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. In addition, concerns have been raised about the potential for induced seismicity from the use of underground injection wells, a predominant method for disposing of waste water (including hydraulic fracturing flowback water) from oil and gas activities. QEP operates injection wells and utilizes injection wells owned by third parties to dispose of waste water associated with its operations. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in others. Further, lawsuits against other companies have been filed by plaintiffs alleging they suffered damages from seismicity caused by injection of waste water into disposal wells, which may make it more expensive or difficult to conduct water disposal activities and to obtain insurance for such activities.

The adoption of greenhouse gas (GHG) emission or other environmental legislation could result in increased operating costs, delays in obtaining air pollution permits for new or modified facilities, and reduced demand for the gas, oil and NGL that QEP produces. Federal and state courts and administrative agencies are considering the scope and scale of climate change regulation under various laws pertaining to the environment, energy use and development. Federal, state and local governments may also pass laws mandating the use of alternative energy sources, such as wind power and solar energy, which may reduce demand for oil and gas. QEP's ability to access and develop new oil and gas reserves may be restricted by climate change regulation, including GHG reporting and regulation. Legislative bills have been proposed in Congress that would regulate GHG emissions through a cap-and-trade system under which emitters would be required to buy allowances for offsets of emissions of GHG. The EPA has adopted final regulations for the measurement and reporting of GHG emitted from certain large facilities and, as discussed above, has proposed additional regulations at 40 C.F.R Part 60, Subpart OOOO to include additional requirements to reduce methane emissions from oil and natural gas facilities. In June 2014, the United States Supreme Court’s holding in Utility Air Regulatory Group v. EPA upheld a portion of EPA’s GHG stationary source permitting program, but also invalidated a portion of it. Upon remand, the EPA is considering how to implement the Court’s decision. The Court’s holding does not prevent states from considering and adopting state-only major source permitting requirements based solely on GHG emission levels. In addition, 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. It is uncertain whether QEP's operations and properties, located in the Northern and Southern Regions of the United States, are exposed to possible physical risks, such as severe weather patterns, due to climate change, whether or not climate change is caused by anthropogenic emissions of GHG. Management does not, however, believe such physical risks are reasonably likely to have a material effect on the Company's financial condition or results of operations. In December 2015, over 190 countries, including the U.S., reached an agreement to reduce global emissions of GHG. To the extent the U.S. and other countries implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse direct or indirect effect on our business.

The adoption and implementation of new statutory and regulatory requirements for swap transactions could have an adverse impact on QEP's ability to mitigate risks associated with its business and increase the working capital requirements to conduct these activities. The Dodd-Frank Act, which was signed into law in July 2010, contains significant derivatives regulation, including a requirement that certain transactions be cleared on exchanges. The Act provides for an exception from these clearing requirements for commercial end-users, such as QEP. The Dodd-Frank Act may, however, require the posting of cash collateral for uncleared swaps and may limit trading in certain oil and gas related derivative contracts by imposing position limits. The rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on QEP’s business remains uncertain.

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.

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 have employment agreements with or maintain key-man insurance for its key management personnel. The loss of services of one or more of its key management personnel could have a negative impact on QEP’s financial condition and results of operations.

In certain areas of QEP’s business, institutional knowledge resides with employees who have many years of service. As these employees retire, QEP may not be able to replace them with employees of comparable knowledge and experience. QEP’s efforts at knowledge transfer could be inadequate. If knowledge transfer, recruiting and retention efforts are inadequate, access to significant amounts of internal historical knowledge and expertise could become unavailable to QEP and could negatively impact QEP’s business.

General economic and other conditions could negatively impact QEP's results. QEP's results may also be negatively affected by changes in global economic conditions; availability and economic viability of oil and gas properties for sale or exploration; rate of inflation and interest rates; assumptions used in business combinations; weather and natural disasters; changes in customers' credit ratings; competition from other forms of energy, other pipelines and storage facilities; effects of accounting policies issued periodically by accounting standard-setting bodies; and terrorist attacks or acts of war.

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 (the Pension Plan), which covers 50 active and suspended participants, or 7%, of QEP's active employees and 164 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, 2015 and 2014, QEP's pension plans were underfunded by $41.0 million and $51.2 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 $7.5 million and $13.0 million during the years ended December 31, 2015 and 2014, respectively, to the Pension Plan and SERP and expects to make contributions of approximately $6.9 million to these pension plans in 2016. 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, 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's systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, QEP may be required to expend additional resources to continue to modify or enhance its protective measures or to investigate and remediate any vulnerability to cyber incidents. QEP does not maintain specialized insurance for possible liability resulting from a cyber attack on its assets that may shut down all or part of QEP's business.

QEP's certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, even if such 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:

- a classified Board of Directors, with only approximately one-third of QEP's Board of Directors elected each year;
- advance notice of provisions 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. These provisions may deter hostile takeover attempts that could result in an acquisition of QEP that could have been financially beneficial to its shareholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Exploration and Production – QEP Energy

QEP's exploration and production business is conducted through QEP Energy in two regions - the Northern Region (including the states of Wyoming, North Dakota, Utah and Colorado) and the Southern Region (including the states of Texas and Louisiana).

Northern Region

Pinedale
QEP Energy's largest property, in terms of proved reserves, is Pinedale, where the Company is actively developing the Lance Pool, which is a tight gas sand reservoir. The depth to the top of the Lance Pool reservoir ranges from 8,500 to 9,500 feet across QEP Energy's leasehold. The Company currently estimates that there are up to approximately 250 additional wells required to fully develop its Pinedale acreage on 5 to 10-acre density. On December 31, 2015, QEP Energy had three operated rigs drilling on the Pinedale Anticline. The Company has been successful in reducing development well costs and increasing production at Pinedale. Included in QEP Energy's 1,071 gross producing wells at Pinedale are 69 wells in which QEP Energy has a small overriding royalty interest.

Williston Basin
QEP Energy is actively developing the Bakken and Three Forks formations in the Williston Basin. The depth to the top of the Bakken Formation ranges from approximately 9,500 feet to 10,000 feet across QEP Energy's leasehold. Multiple benches of the Three Forks formation are approximately 60 to 70 feet below the Middle Bakken formation and are also targets for horizontal drilling. The Company has been successful in reducing development well costs, de-risking unproven reserves, increasing production, increasing the number of future drilling locations and increasing its estimate of recoverable reserves. As of December 31, 2015, QEP Energy had three operated rigs drilling in the Williston Basin.

Uinta Basin
The majority of the Uinta Basin's proved reserves are found in a series of vertically stacked, laterally discontinuous reservoirs at depths of 4,500 feet to deeper than 17,000 feet. QEP Energy had one operated rig drilling in the Uinta Basin at December 31, 2015, targeting the Lower Mesaverde Formation in which QEP Energy holds acreage in the Red Wash Unit and South Red Wash Unit.

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

Southern Region

Permian Basin
QEP Energy is developing oil producing zones in the Wolfcamp and Spraberry formations to vertical depths of 10,000 to 12,000 feet in the Permian Basin. In 2015, QEP transitioned to exclusively drilling horizontal wells. The Company has been successful in reducing development well costs and increasing production. As of December 31, 2015, QEP Energy had two operated rigs drilling in the Permian Basin.

Haynesville/Cotton Valley
QEP Energy holds producing and undeveloped properties in the Haynesville Shale play in northwestern Louisiana and additional lease rights that cover the Hosston and Cotton Valley formations. The top of the Haynesville Shale ranges

from approximately 10,500 feet to 12,500 feet across QEP Energy's leasehold and is deeper than the Hosston and Cotton Valley formations that QEP Energy has been developing in northwest Louisiana since the 1990's. As of December 31, 2015, QEP Energy did not have any operated rigs drilling in the Haynesville/Cotton Valley area, however, there were six gross non-operated wells waiting on completion as of December 31, 2015.

Midcontinent

QEP Energy's Midcontinent operations cover all properties in the Southern Region except the Haynesville/Cotton Valley area of northwestern Louisiana and the Permian Basin properties in west Texas and are widely distributed. QEP sold the majority of its Midcontinent properties in 2014, including its properties in the Woodford "Cana" Shale in western Oklahoma, Granite Wash/Atoka Wash in the Texas panhandle and western Oklahoma and has continued to divest other non-core properties within this area throughout 2015. As of December 31, 2015, QEP Energy did not have any operated rigs drilling in the Midcontinent area.

Reserves – QEP Energy

At December 31, 2015 and 2014, QEP Energy's estimated proved reserves were approximately 3,620.2 Bcfe and 3,931.9 Bcfe, respectively, of which 96% and 93%, respectively, were Company operated. Proved developed reserves represented 58% and 56% of the Company's total proved reserves at December 31, 2015 and 2014, respectively, while the remaining reserves were classified as proved undeveloped. All reported reserves are located in the United States. QEP Energy does not have any long-term supply contracts with foreign governments, reserves of equity investees or reserves of subsidiaries with a significant minority interest. QEP Energy's estimated proved reserves are summarized in the table below:

	December 31, 2015				December 31, 2014			
	Gas (Bcf)	Oil (MMbbl)	NGL (MMbbl)	Total (Bcfe)[1]	Gas (Bcf)	Oil (MMbbl)	NGL (MMbbl)	Total (Bcfe)[1]
Proved developed reserves	1,245.3	109.7	34.4	2,109.4	1,288.4	99.3	52.2	2,197.5
Proved undeveloped reserves	863.6	83.4	24.4	1,510.8	1,028.8	73.2	44.4	1,734.4
Total proved reserves	2,108.9	193.1	58.8	3,620.2	2,317.2	172.5	96.6	3,931.9

(1) Oil and NGL are converted to natural gas equivalents at the ratio of one barrel of crude oil, condensate or NGL to six Mcf of equivalent natural gas.

QEP Energy's reserve, production and production life index for each of the years ended December 31, 2013, through December 31, 2015, are summarized in the table below:

Year Ended December 31,	Year End Reserves (Bcfe)	Gas, Oil and NGL Production (Bcfe)	Reserve Life Index [1] (Years)
2013	4,061.9	309.0	13.1
2014	3,931.9	322.7	12.2
2015	3,620.2	326.8	11.1

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

Proved Reserves

Reserve and related information is presented consistent with the requirements of the SEC's rules for the Modernization of Oil and Gas Reporting. These rules expand the use of reliable technologies to estimate and categorize reserves and require the use of the 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 16 – Supplemental Oil and Gas Information (unaudited), in Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding estimates of proved reserves and the preparation of such estimates.

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

	December 31,			
	2015		2014	
Northern Region	(Bcfe)	(% of total)	(Bcfe)	(% of total)
Pinedale	1,125.0	31 %	1,450.1	37 %
Williston Basin	1,085.7	30 %	858.9	22 %
Uinta Basin	558.9	16 %	623.0	16 %
Other Northern	74.4	2 %	94.0	2 %
Southern Region				
Haynesville/Cotton Valley	396.5	11 %	493.9	13 %
Permian Basin	374.0	10 %	375.7	10 %
Midcontinent	5.7	— %	36.3	— %
Total QEP Energy	3,620.2	100 %	3,931.9	100 %

Estimates of the quantity of proved reserves decreased during 2015 primarily due to lower gas, oil, and NGL prices. Other factors impacting this decrease include operating in ethane rejection in Pinedale and in the Uinta Basin, as well as decreases in estimated proved reserves in Pinedale and Haynesville/Cotton Valley as a result of fewer PUD locations. These proved reserve decreases were partially offset by extensions and additions in the Williston, Uinta, and Permian basins from the recognition of additional PUD locations due to the increased drilling program.

Proved Undeveloped Reserves

Significant changes to PUD reserves that occurred during 2015 are summarized in the table below:

	2015
	(Bcfe)
Proved undeveloped reserves at January 1,	1,734.4
Transferred to proved developed reserves	(397.5)
Revisions to previous estimates[(1)]	(778.9)
Extensions and discoveries[(2)]	945.4
Purchase of reserves in place[(3)]	7.4
Proved undeveloped reserves at December 31,[(4)]	1,510.8

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(1) Revisions of previous estimates in 2015 include: 514.2 Bcfe of negative revisions due to lower pricing and 303.7 Bcfe of negative revisions unrelated to pricing, partially offset by 39.0 Bcfe of positive performance revisions. Negative pricing revisions were driven by lower gas, oil and NGL prices. Negative other revisions were primarily the result of slowing the pace of planned drilling activity and operating in ethane rejection in Pinedale and the Uinta Basin.

(2) The increase in reserves due to extensions and discoveries in 2015 was comprised of 325.8 Bcfe in the Williston Basin, 300.6 Bcfe in the Uinta Basin, 242.1 Bcfe in the Permian Basin, 45.9 Bcfe in Pinedale, and 31.0 Bcfe in Haynesville/Cotton Valley. Extensions and discoveries relate to new PUD locations driven by drilling activity in 2015, as well as new compression projections in Pinedale.

(3) Purchase of reserves in place in 2015 related to the acquisition of additional interests in QEP's operated wells in the Williston Basin as discussed in Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K.

(4) All of QEP Energy's PUD reserves at December 31, 2015, are scheduled to be developed within five years from the date such locations were initially disclosed as PUD reserves; however, long-term development of gas reserves in Pinedale is governed by the BLM's September 2008 ROD on the FSEIS. Under the ROD, QEP Energy is allowed to drill and complete wells year-round in designated concentrated development areas. The ROD contains additional requirements and restrictions on the sequence of development, which requires the Company to develop its leasehold from the south to the north. These restrictions result in protracted, phased development that is beyond the

control of the Company. The Company has an ongoing development plan and the financial capability to continue development in the manner estimated. Additionally, QEP Energy plans to develop its PUD reserves prior to lease expiration or extend the term of the lease.

The costs incurred to continue the development of PUD reserves were approximately $811.3 million, $796.7 million, and $645.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. The costs incurred in 2015 related to the drilling of PUD locations in QEP's operating areas. This investment resulted in the transfer of 397.5 Bcfe of PUD reserves to proved developed reserves in 2015, representing 23% of the Company's total PUD reserves as of December 31, 2014.

QEP estimates that its future development costs relating to the development of PUD reserves are approximately $438.9 million in 2016, $472.8 million in 2017, and $306.8 million in 2018. The scheduled PUD development costs are reduced from historical levels in conjunction with our efforts to reduce drilling and completion activities, gain operational efficiencies, slow production growth and preserve liquidity in the current commodity price environment. 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, cash on hand and availability under its credit facility will be sufficient to cover these estimated future development costs. PUD reserves related to major development projects will be reclassified to proved developed reserves when production commences.

Internal Controls Over Proved Reserve Estimates, Technical Qualifications and Technologies Used
Estimates of proved oil and gas reserves have been completed in accordance with professional engineering standards and the Company's established internal controls, which includes the compliance oversight of a multi-functional reserves review committee reporting to the Company's Board of Directors. The Company retained Ryder Scott Company (RSC) and DeGolyer and MacNaughton (D&M), independent oil and gas reserve evaluation engineering consultants, to prepare the estimates of 100% of its proved reserves as of December 31, 2015 and 2014. RSC prepared approximately 90% and D&M prepared approximately 10% of the Company's total estimated net proved reserves as of December 31, 2015. RSC prepared approximately 91% and D&M prepared approximately 9% of the Company's total net proved reserves as of December 31, 2014. The Company utilized RSC to prepare the estimates of 100% of the Company's total net proved reserves as of December 31, 2013.

The individual at RSC who was responsible for overseeing the preparation of QEP's reserve estimates as of December 31, 2015, for its Haynesville, Pinedale, Williston, Other Northern, Uinta and Midcontinent areas, is a registered Professional Engineer in the State of Colorado and graduated with a Masters of Science degree in Geological Engineering from the University of Missouri at Rolla in 1976. The individual has over 30 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. The individual at D&M who was responsible for overseeing the preparation of QEP’s Permian Division reserves estimates as of December 31, 2015, is a registered Professional Engineer in the State of Texas and graduated with a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin in 1984. The individual has over 31 years of experience in the petroleum industry, including experience estimating and evaluating petroleum reserves. A more detailed letter including each individual's professional qualifications has been filed as part of Exhibit 99.1 to this report for RSC and as part of Exhibit 99.2 for D&M.

The individual at QEP responsible for insuring the accuracy of the reserve estimate preparation material provided to RSC and D&M and reviewing the estimates of reserves received from RSC and D&M is QEP's Chief Engineer. This individual is a member of the Society of Petroleum Engineers and graduated with a Bachelors of Science degree in Petroleum Engineering from North Dakota State University in 1994. This individual has over 21 years of experience in the petroleum industry, including more than 16 years reservoir engineering experience in most of the active domestic basins in the U.S.

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, volumetric methods or a combination of methods.

All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. Performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production data available through late 2015, in those cases where such data were considered to be definitive. For wells currently in production, 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.

Approximately 93% of QEP's proved developed non-producing and undeveloped reserves included in this Annual Report on Form 10-K were estimated by analogy to offset producing wells. The remaining 7% of such reserves was estimated by the volumetric method. The volumetric analysis utilizes pertinent well data furnished to RSC and D&M by QEP or obtained from available public data sources through late 2015. 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 in 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.

Refer to Note 16 – Supplemental Oil and Gas Information (unaudited) of the Consolidated Financial Statements included in Item 8 of Part II of this Annual Report on Form 10-K for additional information pertaining to QEP Energy's proved reserves as of the end of each of the last three years.

In addition to this filing, QEP Energy will file reserve estimates as of December 31, 2015, 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 for only 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.

Production, Prices and Production Costs – QEP Energy

The following table sets forth the net production volumes and field-level prices of gas, oil and NGL produced, and the related operating expenses, for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Production volumes			
Gas (Bcf)	181.1	179.3	218.9
Oil (Mbbl)	19,582.3	17,146.5	10,209.7
NGL (Mbbl)	4,704.3	6,769.1	4,811.3
Total equivalent production (Bcfe)	326.8	322.7	309.0
Average field-level price (1)			
Gas (per Mcf)	$2.59	$4.33	$3.56
Oil (per bbl)	42.59	79.79	89.78
NGL (per bbl)	16.98	32.95	39.95
Lifting costs (per Mcfe)			
Lease operating expense	$0.73	$0.74	$0.59
Production taxes	0.35	0.63	0.51
Total lifting costs	$1.08	$1.37	$1.10

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

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

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Gas production volumes (Bcf)					
Northern Region					
Pinedale	87.5	75.0	80.0	12.5	(5.0)
Williston Basin	11.3	6.6	2.7	4.7	3.9
Uinta Basin	22.7	17.9	18.6	4.8	(0.7)
Other Northern	9.4	9.3	10.3	0.1	(1.0)
Southern Region					
Haynesville/Cotton Valley	43.2	49.5	71.8	(6.3)	(22.3)
Permian Basin	4.4	3.2	—	1.2	3.2
Midcontinent	2.6	17.8	35.5	(15.2)	(17.7)
Total production	181.1	179.3	218.9	1.8	(39.6)

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

	Year ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Oil production volumes (Mbbl)					
Northern Region					
Pinedale	716.6	632.0	657.6	84.6	(25.6)
Williston Basin	14,871.8	13,130.9	7,026.2	1,740.9	6,104.7
Uinta Basin	848.6	893.3	924.9	(44.7)	(31.6)
Other Northern	186.5	200.9	237.7	(14.4)	(36.8)
Southern Region					
Haynesville/Cotton Valley	33.6	35.3	43.2	(1.7)	(7.9)
Permian Basin	2,791.2	1,582.2	—	1,209.0	1,582.2
Midcontinent	134.0	671.9	1,320.1	(537.9)	(648.2)
Total production	19,582.3	17,146.5	10,209.7	2,435.8	6,936.8

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

	Year ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
NGL production volumes (Mbbl)					
Northern Region					
Pinedale	1,528.6	3,350.2	1,787.5	(1,821.6)	1,562.7
Williston Basin	1,953.4	1,010.5	390.0	942.9	620.5
Uinta Basin	287.6	679.0	463.8	(391.4)	215.2
Other Northern	19.6	14.9	36.7	4.7	(21.8)
Southern Region					
Haynesville/Cotton Valley	28.6	37.3	21.3	(8.7)	16.0
Permian Basin	815.4	511.0	—	304.4	511.0
Midcontinent	71.1	1,166.2	2,112.0	(1,095.1)	(945.8)
Total production	4,704.3	6,769.1	4,811.3	(2,064.8)	1,957.8

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

	Year ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Total production volumes (Bcfe)					
Northern Region					
Pinedale	101.0	98.9	94.7	2.1	4.2
Williston Basin	112.3	91.4	47.2	20.9	44.2
Uinta Basin	29.5	27.3	26.9	2.2	0.4
Other Northern	10.6	10.6	11.9	—	(1.3)
Southern Region					
Haynesville/Cotton Valley	43.6	49.9	72.2	(6.3)	(22.3)
Permian Basin	26.0	15.8	—	10.2	15.8
Midcontinent	3.8	28.8	56.1	(25.0)	(27.3)
Total production	326.8	322.7	309.0	4.1	13.7

A regional comparison of average field-level prices and average production costs per Mcfe is shown in the following table:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
Average field-level gas price (per Mcf)					
Northern Region	$2.58	$4.26	$3.58	$(1.68)	$0.68
Southern Region	2.60	4.44	3.54	(1.84)	0.90
Average field-level gas price	2.59	4.33	3.56	(1.74)	0.77
Average field-level oil price (per bbl)					
Northern Region	$41.78	$78.87	$89.35	$(37.09)	$(10.48)
Southern Region	47.16	85.76	92.60	(38.60)	(6.84)
Average field-level oil price	42.59	79.79	89.78	(37.20)	(9.99)
Average field-level NGL price (per bbl)					
Northern Region	$18.06	$33.22	$46.56	$(15.16)	$(13.34)
Southern Region	12.49	32.15	31.65	(19.66)	0.50
Average field-level NGL price	16.98	32.95	39.95	(15.97)	(7.00)
Lease Operating Expense (per Mcfe)					
Northern Region	$0.66	$0.63	$0.60	$0.03	$0.03
Southern Region	0.97	0.90	0.57	0.07	0.33
Average production cost	0.73	0.74	0.59	(0.01)	0.15

Northern Region

Pinedale

Production from Pinedale increased 2% to 101.0 Bcfe during 2015 compared to 2014. This increase in production was primarily a result of increased gas production due to continued net well completions in 2014 and 2015 and better performing well completions from the new wells drilled in 2015. This increase was mostly offset by a decrease in NGL production due to operating in ethane rejection throughout the majority of 2015 compared to ethane recovery in 2014.

Production from Pinedale increased 4% to 98.9 Bcfe during 2014 compared to 2013. This increase in production was primarily a result of increased NGL production due to recovering ethane throughout the majority of 2014 compared to rejecting ethane throughout the majority of 2013.

During each of the three years ended December 31, 2015, 2014 and 2013, Pinedale's production represented 31% of QEP Energy's total production.

Williston Basin
In the Williston Basin, production increased 23% to 112.3 Bcfe during 2015 compared to 2014, due to increased oil, gas and NGL production. The increase in production volumes was primarily attributable to continued development drilling and completion activity.

During 2014, production increased 94% to 91.4 Bcfe, compared to 2013, primarily due to increased oil and NGL production. The increase in production volumes was primarily attributable to ongoing development of the properties acquired in the Williston Basin in 2012, which contributed 6,347.5 Mbbls of increased oil and NGL volume. The remaining 377.7 Mbbls increase in 2014 related to increased development drilling on QEP's existing pre-acquisition acreage.

During the years ended December 31, 2015, 2014 and 2013, Williston Basin production represented 34%, 28%, and 15%, respectively, of QEP Energy's total production.

Uinta Basin
In the Uinta Basin, production increased 8% to 29.5 Bcfe during 2015 compared to 2014, due primarily to increased gas production due to new Lower Mesaverde well completions in 2015, partially offset by a decrease in NGL production due to operating in ethane rejection throughout the majority of 2015 compared to ethane recovery in 2014.

During 2014, production increased 1% to 27.3 Bcfe, compared to 2013, due primarily to increased NGL production as a result of recovering ethane throughout the majority of 2014 compared to rejecting ethane in the majority of 2013.

During the years ended December 31, 2015, 2014 and 2013, Uinta Basin production represented 9%, 8%, and 9%, respectively, of QEP Energy's total production.

Other Northern
QEP Energy's Other Northern production remained flat during 2015 compared to 2014, due to a slight increase in gas production, primarily from 4.0 net well completions, offset by a slight decrease in oil production.

Other Northern production decreased 11% to 10.6 Bcfe during 2014 compared to 2013, due to declining production from older wells and lack of new drilling.

During the years ended December 31, 2015, and 2014, Other Northern production represented 3% of QEP Energy's total production, compared to 4% for the year ended December 31, 2013.

Southern Region

Haynesville/Cotton Valley
Production from the Haynesville Shale and Cotton Valley decreased 13% to 43.6 Bcfe during 2015 when compared to 2014. Decreased production was due to natural decline and the continued suspension of QEP's operated drilling program, partially offset by 3.2 net non-operated well completions in 2015.

Production from the Haynesville Shale and Cotton Valley decreased 31% to 49.9 Bcfe during 2014 when compared to 2013. Decreased production was due to natural decline and the continued suspension of QEP's operated drilling program.

During the years ended December 31, 2015, 2014 and 2013, Haynesville/Cotton Valley's production comprised 13%, 15%, and 23%, respectively, of QEP Energy's total production.

Permian Basin

In February 2014, QEP Energy acquired approximately 26,500 net acres of producing and undeveloped oil and gas properties in the Permian Basin. Production from the Permian Basin increased 65% to 26.0 Bcfe during 2015 when compared to 2014, due to increased horizontal well development combined with a full year of production in 2015 compared to 10 months of production in 2014.

During the years ended December 31, 2015 and 2014, Permian Basin production represented 9% and 5%, respectively, of QEP Energy's total production.

Midcontinent

Production in the Midcontinent decreased 87% to 3.8 Bcfe during 2015 when compared to 2014, due to divestitures of non-core properties in the second and fourth quarters of 2014.

Production in the Midcontinent decreased 49% to 28.8 Bcfe during 2014 compared to 2013, due to divestitures of non-core properties at the end of the second quarter of 2014.

During the years ended December 31, 2015, 2014 and 2013, Midcontinent production represented 1%, 9%, and 18% of QEP Energy's total production, respectively.

Productive Wells

The following table summarizes the Company's productive wells as of December 31, 2015, all of which are located in the U.S.:

	Gas		Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Northern Region						
Pinedale [1]	1,071	660.2	—	—	1,071	660.2
Williston Basin	—	—	756	292.8	756	292.8
Uinta Basin	697	511.8	1,527	198.4	2,224	710.2
Other Northern	517	199.0	27	9.2	544	208.2
Southern Region						
Haynesville/Cotton Valley	847	457.5	1	0.1	848	457.6
Permian Basin	—	—	375	347.7	375	347.7
Midcontinent	551	33.0	115	7.0	666	40.0
Total productive wells	3,683	1,861.5	2,801	855.2	6,484	2,716.7

(1) Gross productive wells includes 69 wells in which QEP only owns a small overriding royalty interest.

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

The Company also holds numerous overriding royalty interests in oil and gas wells, a portion of which is convertible to working interests after recovery of certain costs by third parties. Once the overriding royalty interests are converted to working interests, these wells are included in the Company's gross and net well count.

Leasehold Acreage

The following table summarizes developed and undeveloped leasehold acreage in which the Company owns a working interest or mineral interest as of December 31, 2015. "Undeveloped Acreage" includes leasehold interests that already may 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 and 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	171,987	115,053	78,797	17,540	250,784	132,593
Montana	37,817	15,649	332,686	58,038	370,503	73,687
New Mexico	7,740	4,266	24,971	2,476	32,711	6,742
North Dakota	204,319	68,167	170,833	55,704	375,152	123,871
South Dakota	40	40	203,558	107,551	203,598	107,591
Wyoming	306,886	204,348	97,653	52,658	404,539	257,006
Utah	218,244	166,382	214,179	139,184	432,423	305,566
Kansas	46,153	20,872	35,699	12,805	81,852	33,677
Louisiana	69,754	62,045	1,841	1,495	71,595	63,540
Oklahoma	62,222	36,192	93,882	15,332	156,104	51,524
Texas	31,410	22,393	90,529	43,914	121,939	66,307
Other	14,255	3,888	158,108	43,593	172,363	47,481
Total	1,170,827	719,295	1,502,736	550,290	2,673,563	1,269,585

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

(2) Undeveloped acreage is leased acreage 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

A portion of the leases summarized in the preceding table will expire at the end of their respective primary terms unless the leases are renewed or drilling or production has occurred on the acreage subject to the lease prior to that date. Leases held by production 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,		
2016	19,806	18,226
2017	56,260	56,260
2018	54,034	13,047
2019	19,521	15,664
2020 and later	43,961	37,393
Total	193,582	140,590

Drilling Activity

The following table summarizes the 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 the drilling was initiated) during the years indicated:

	Developmental Wells				Exploratory Wells			
	Productive		Dry		Productive		Dry	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Year Ended December 31, 2015								
Northern Region								
Pinedale	107	68.1	—	—	—	—	—	—
Williston Basin	154	59.7	—	—	—	—	—	—
Uinta Basin	30	11.2	—	—	—	—	—	—
Other Northern	3	3.0	—	—	1	1.0	—	—
Southern Region								
Haynesville/Cotton Valley	24	3.2	—	—	—	—	—	—
Permian Basin	38	32.5	—	—	—	—	—	—
Midcontinent	4	0.1	—	—	—	—	—	—
Total	360	177.8	—	—	1	1.0	—	—
Year Ended December 31, 2014								
Northern Region								
Pinedale	116	82.4	—	—	—	—	—	—
Williston Basin	199	80.6	—	—	—	—	—	—
Uinta Basin	196	6.5	—	—	—	—	—	—
Other Northern	3	3.0	—	—	1	1.0	—	—
Southern Region								
Haynesville/Cotton Valley	40	3.2	1	0.3	—	—	—	—
Permian Basin	71	63.2	—	—	—	—	—	—
Midcontinent	32	2.3	—	—	—	—	—	—
Total	657	241.2	1	0.3	1	1.0	—	—
Year Ended December 31, 2013								
Northern Region								
Pinedale	111	61.5	—	—	—	—	—	—
Williston Basin	176	70.7	—	—	—	—	—	—
Uinta Basin	224	39.4	—	—	—	—	—	—
Other Northern	6	0.2	—	—	—	—	1	1.0
Southern Region								
Haynesville/Cotton Valley	11	3.4	—	—	—	—	—	—
Midcontinent	135	29.3	—	—	—	—	—	—
Total	663	204.5	—	—	—	—	1	1.0

The following table presents operated and non-operated well completions for the year ended December 31, 2015:

	Operated Completions		Non-operated Completions	
	Gross	Net	Gross	Net
Northern Region				
Pinedale[1]	107	68.1	—	—
Williston Basin	70	55.0	84	4.7
Uinta Basin	11	11.0	19	0.2
Other Northern	4	4.0	—	—
Southern Region				
Haynesville/Cotton Valley	—	—	24	3.2
Permian Basin[2]	36	31.6	2	0.9
Midcontinent	—	—	4	0.1

(1) Gross completions includes eight wells for the year ended December 31, 2015, in which QEP only owns a small overriding royalty interest.
(2) Operated completions include eight gross, 7.4 net, vertical wells for the year ended December 31, 2015.

The following table presents operated and non-operated wells drilling and waiting on completion at December 31, 2015:

	Operated				Non-operated			
	Drilling		Waiting on completion		Drilling		Waiting on completion	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Northern Region								
Pinedale	8	5.0	20	12.5	—	—	—	—
Williston Basin	5	4.6	24	22.8	1	—	19	1.0
Uinta Basin	2	2.0	6	6.0	—	—	3	—
Other Northern	—	—	—	—	—	—	—	—
Southern Region								
Haynesville/Cotton Valley	—	—	—	—	—	—	6	1.3
Permian Basin	5	5.0	4	3.9	—	—	—	—
Midcontinent	—	—	—	—	—	—	2	0.1

QEP typically utilizes multi-well pad drilling where practical. Wells drilled are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location. In certain properties in the Northern Region, QEP typically suspends completion activities due to adverse weather conditions in the fourth quarter and resumes completion in the first quarter as weather conditions allow. As a result, QEP had 54 gross operated wells waiting on completion as of December 31, 2015.

Energy Marketing – QEP Marketing and Other

QEP Marketing owns and operates an underground gas storage reservoir in southwestern Wyoming (Clear Creek). Clear Creek has capacity of approximately 8 Bcf, comprised of approximately 4 Bcf of QEP Marketing-owned cushion gas and working gas storage capacity of about 4 Bcf.

In addition, QEP Marketing owns a membership interest in a gas gathering system located in Louisiana (Haynesville Gathering). Haynesville Gathering includes 200 miles of gas gathering facilities with approximate throughput capacity of 2,000 MMcf/d and a treating facility with throughput capacity of 600 MMcf/d. The system primarily provides services to QEP Energy.

Delivery Commitments – QEP Resources

QEP is a party to various long-term sales commitments for physical delivery of gas with future firm delivery commitments as follows:

Period	Delivery Commitments (millions of MMBtu)
2016	84.8
2017	14.7
2018	2.7
Thereafter	—

These commitments are physical delivery obligations with prices based on prevailing index prices for gas at the time of delivery. None of these commitments requires the Company to deliver gas produced specifically from any of the Company's properties. The Company believes that its production and reserves should be adequate to meet these term sales commitments. If for some reason the Company's gas production is not sufficient to satisfy its firm delivery commitments, the Company believes it can purchase sufficient volumes of gas in the market at index-related prices to satisfy its commitments. 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 and storage commitments related to gas deliveries.

In addition, at December 31, 2015, the Company did not have a significant amount of production from QEP Energy's owned properties that was subject to priorities, proration or third-party imposed 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.

ITEM 3. LEGAL PROCEEDINGS

Yannick Gagné Lawsuit and Related Suits – Injured parties filed the initial class action lawsuit in July 2013, and plaintiffs added QEP and other operators as defendants in February 2014. Plaintiffs in this initial lawsuit and subsequent related lawsuits sought to obtain compensation for persons who sustained damages as a result of the July 6, 2013, train derailment in Lac-Mégantic, Quebec, which resulted in substantial loss of life and property. The rail company that transported the crude oil filed for bankruptcy protection following the accident. The plaintiffs contended that QEP, and other producer defendants, sold Bakken crude oil to third-party purchasers in North Dakota, who resold the oil and transported it on the derailed train. Plaintiffs alleged that QEP and the producer defendants, among other things, failed to ensure that the oil was adequately processed to remove volatile gases and vapors, failed to take reasonable care to ensure that the oil was properly labeled and shipped and failed to identify the risk of the train derailment and take action to prevent it. The plaintiffs sought unspecified damages. During the third quarter of 2015, QEP was served with additional complaints in state and federal courts in Maine, Texas and Illinois, each of which made similar claims to those in the Yannick Gagné case. In March 2015, many of the defendants, including QEP, reached a conditional settlement agreement with trustees in both Canadian and U.S. bankruptcy courts to resolve all claims, including all claims raised in all related tort actions in Canada and the United States. The conditions were met in early November 2015, and at that time QEP paid a settlement amount (a significant portion of which was covered by QEP’s insurers) and received a full release of all known and unknown claims. The settlement amount paid by QEP was not material to QEP’s financial position or results of operations.

Environmental Matters – 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 instances of non-compliance to the LDEQ and is working with the department to resolve the NOPP. The LDEQ has assumed lead responsibility for enforcement of the NOPP, and may require the Company to pay a monetary penalty.

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, 2016, QEP had 6,015 shareholders of record. The declaration and payment of dividends are at the discretion of QEP's Board of Directors and the amount thereof will depend on QEP's results of operations, financial condition, contractual restrictions, cash requirements, future prospects and other factors deemed relevant by the Company's Board of Directors. In February 2016, in response to the current commodity price environment, the Board of Directors indefinitely suspended the payment of quarterly dividends.

The following table is a summary of the high and low sales price per share of QEP's common stock as reported on the NYSE as well as the dividends paid per share per quarter for 2015 and 2014:

	High price	Low price	Dividend
	(per share)		
2015			
First quarter	$23.21	$18.29	$0.02
Second quarter	24.04	18.11	0.02
Third quarter	18.59	11.20	0.02
Fourth quarter	16.95	11.03	0.02
Total			$0.08
2014			
First quarter	$33.32	$25.93	$0.02
Second quarter	34.60	29.59	0.02
Third quarter	35.91	30.33	0.02
Fourth quarter	31.00	18.15	0.02
Total			$0.08

Stock Performance Graph

The following stock performance information in this Item 5 of this Annual Report on Form 10-K 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 2015, QEP made changes to its peer group to remove Noble Energy, Inc., Quicksilver Resources, Inc. and Pioneer Natural Resources Company due to dissimilar financial characteristics. In addition, Forest Oil Corporation was acquired in December 2014 and therefore was removed from the peer group. Laredo Petroleum, Inc., Oasis Petroleum Inc. and Sandridge 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:

Cabot Oil & Gas Corporation	Pioneer Natural Resources Company
Cimarex Energy Company	Range Resources Corporation
Concho Resources Inc.	SM Energy Company
Denbury Resources Inc.	Southwestern Energy Company
Forest Oil Corporation	Ultra Petroleum Corporation

Newfield Exploration Company
Noble Energy, Inc.
Quicksilver Resources, Inc.
Whiting Petroleum Corporation
WPX Energy, Inc.

After the change in peer companies, QEP's 2015 peer group consisted of the following:

Cabot Oil & Gas Corporation	Range Resources Corporation
Cimarex Energy Company	Sandridge Energy Inc.
Concho Resources Inc.	SM Energy Company
Denbury Resources Inc.	Southwestern Energy Company
Laredo Petroleum, Inc.	Ultra Petroleum Corporation
Newfield Exploration Company	Whiting Petroleum Corporation
Oasis Petroleum Inc.	WPX Energy, Inc.

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 July 1, 2010, which is the date when QEP's common stock began trading on the NYSE;
- 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 were reinvested on the relevant payment dates.

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

The following repurchases of QEP shares were made by QEP in association with vested restricted stock awards withheld for taxes.

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, 2015 - October 31, 2015	17,297	$ 24.01	—	$400.3
November 1, 2015 - November 30, 2015	3,524	$ 16.13	—	$400.3
December 1, 2015 - December 31, 2015	194	$ 12.43	—	$—

(1) All of the shares purchased during the three-month period ended December 31, 2015, were acquired from employees in connection with the settlement of income tax and related benefit withholding obligations arising from vesting of restricted stock grants.

In January 2014, QEP's Board of Directors authorized the repurchase of up to $500.0 million of the Company's outstanding shares of common stock. This program expired on December 31, 2015. During the year ended December 31, 2015, no shares were repurchased under this program.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data for the five years ended December 31, 2015, is provided in the table below. Our financial results for prior periods have been recast, in accordance with GAAP, to reflect the impact of the Midstream Sale and the revisions to our revenues from purchased oil sales. See footnotes (4) and (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,				
	2015 [1][2]	2014 [1][2]	2013[1]	2012[1]	2011
	(in millions, except per share amounts)				
Results of Operations					
Revenues [3][4]	$2,018.6	$3,293.2	$2,685.1	$2,071.7	$2,835.0
Operating income (loss)	(377.6)	(847.3)	203.0	(321.2)	267.2
Income (loss) from continuing operations	(149.4)	(409.5)	52.1	2.4	118.1
Net income from discontinued operations, net of income tax[5]	—	1,193.9	107.3	125.9	149.1
Net income (loss)	(149.4)	784.4	159.4	128.3	267.2
Earnings (loss) per common share					
Basic from continuing operations	$(0.85)	$(2.28)	$0.29	$0.01	$0.67
Basic from discontinued operations[5]	—	6.64	0.60	0.71	0.84
Basic total	$(0.85)	$4.36	$0.89	$0.72	$1.51
Diluted from continuing operations	$(0.85)	$(2.28)	$0.29	$0.01	$0.66
Diluted from discontinued operations[5]	—	6.64	0.60	0.71	0.84
Diluted total	$(0.85)	$4.36	$0.89	$0.72	$1.50
Weighted-average common shares outstanding					
Used in basic calculation	176.6	179.8	179.2	177.8	176.5
Used in diluted calculation	176.6	179.8	179.5	178.7	178.4
Dividends per common share	$0.08	$0.08	$0.08	$0.08	$0.08
Financial Position					
Total Assets at December 31,	$8,425.5	$9,286.8	$9,408.9	$9,108.5	$7,442.7
Capitalization at December 31,					
Long-term debt	2,218.8	2,218.1	2,997.5	3,206.9	1,679.4
Total equity	3,947.9	4,075.3	3,876.8	3,313.7	3,352.1
Total Capitalization	$6,166.7	$6,293.4	$6,874.3	$6,520.6	$5,031.5
Cash Flow from Operations					
Net cash provided by operating activities	$481.3	$1,542.5	$1,191.7	$1,296.0	$1,292.6
Capital expenditures	(1,239.4)	(2,726.4)	(1,602.6)	(2,799.7)	(1,431.1)
Net cash provided by (used in) investing activities	(1,217.6)	578.2	(1,441.5)	(2,794.5)	(1,422.9)
Net cash provided by (used in) financing activities	(47.7)	(990.6)	279.8	1,498.5	130.3
Non-GAAP Measure					
Adjusted EBITDA [6]	$1,029.3	$1,582.7	$1,536.7	1,409.0	1,380.7

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(1) During the years ended December 31, 2015, 2014, 2013 and 2012, the results are impacted by the Company's acquisition of oil and gas properties in the Williston Basin for an aggregate purchase price of $1.4 billion, which occurred on September 27, 2012.

(2) During the years ended December 31, 2015 and 2014, the results are impacted by the Permian Basin Acquisition, which occurred on February 25, 2014, and the property sales in the Midcontinent, which occurred during the second and fourth quarters of 2014. See Note 2 – Acquisitions and Divestitures, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on the Permian Basin Acquisition and property divestitures.

(3) Revenue for the year ended December 31, 2011, reflects the impact of QEP's settled derivative contracts, which during the years ended December 31, 2015, 2014, 2013 and 2012, is reflected below operating income (loss). See Note 7 – Derivative Contracts, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on derivative contract settlements in the years ended December 31, 2015, 2014 and 2013.

(4) In the fourth quarter of 2015, the Company determined that certain purchased oil transactions that were included in "Revenues" on a gross basis for the year ended December 31, 2014, should have been reported net, as the transactions were with the same counterparty and were entered into in contemplation of one another. See Note 1 – Summary of Significant Accounting Policies in Item 8 of Part II of this Annual Report on Form 10-K for additional information. The Company has recast its revenues for the year ended December 31, 2014, to conform to the presentation for the year ended December 31, 2015.

(5) In December 2014, QEP completed the Midstream Sale. QEP Field Services' financial results (excluding results of the Haynesville gathering system) have been reflected as discontinued operations and all prior periods have been reclassified.

(6) 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, and certain other non-cash and/or non-recurring items. Management focuses on Adjusted EBITDA to assess the Company's operating results. Management believes Adjusted EBITDA is an important measure for comparing the Company's financial performance to other oil and gas producing companies. Because not all companies use identical calculations, our presentation of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

The following table reconciles QEP's net income to Adjusted EBITDA:

	Year Ended December 31,				
	2015	2014	2013	2012	2011
	(in millions)				
Net income (loss)	$(149.4)	$784.4	$159.4	$128.3	$267.2
Net income from discontinued operations, net of tax	—	(1,193.9)	(107.3)	(125.9)	(149.1)
Net income (loss) from continuing operations	(149.4)	(409.5)	52.1	2.4	118.1
Unrealized (gains) losses on derivative contracts	183.7	(374.4)	88.7	(63.2)	(117.7)
Net (gain) loss from asset sales	(4.6)	148.6	(103.5)	(1.2)	(1.4)
Interest and other income	(3.0)	(12.8)	(15.2)	(15.0)	(9.2)
Income tax provision (benefit)	(93.6)	(232.5)	60.1	(1.9)	65.5
Interest expense	145.6	169.1	165.1	126.3	92.1
Accrued litigation loss contingency	—	—	—	115.0	—
Loss from early extinguishment of debt	—	2.0	—	0.6	0.7
Pension curtailment (1)	11.2	—	—	—	—
Depreciation, depletion and amortization	881.1	994.7	963.8	850.2	716.9
Impairment	55.6	1,143.2	93.0	133.0	218.2
Exploration expenses	2.7	9.9	11.9	11.2	10.5
Adjusted EBITDA from continuing operations	1,029.3	1,438.3	1,316.0	1,157.4	1,093.7
Adjusted EBITDA from discontinued operations (2)	—	144.4	220.7	251.6	287.0
Adjusted EBITDA	$1,029.3	$1,582.7	$1,536.7	$1,409.0	$1,380.7

(1) The pension curtailment was a non-cash expense incurred during the year ended December 31, 2015, due to changes in the Company's pension plan (see Note 12 – Employee Benefits in Item 8 of Part II of this Annual Report

on Form 10-K for additional information). The Company believes that the pension curtailment does not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the loss from the calculation of Adjusted EBITDA.

(2) See Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, for a reconciliation of Adjusted EBITDA from discontinued operations to Net Income attributable to QEP from discontinued operations.

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 a 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 2014 Annual Report on Form 10-K/A filing, and analyzes the changes in the results of operations between the years ended December 31, 2015 and 2014, and between the years ended December 31, 2014 and 2013.

OVERVIEW

QEP Resources, Inc. (QEP or the Company) is a holding company with two principal subsidiaries, QEP Energy Company and QEP Marketing Company, which are engaged in two primary lines of business: (i) oil and gas exploration and production (QEP Energy) and (ii) oil and gas marketing, operation of a gas gathering system and an underground gas storage facility and corporate activities (QEP Marketing and Other).

The Company has substantial acreage positions and operations in some of the most prolific hydrocarbon resource plays in the continental United States, including the Williston Basin, Permian Basin, Pinedale Anticline, Uinta Basin and Haynesville Shale. These resource plays are characterized by unconventional oil or gas accumulations in continuous tight sands or shales that underlie broad geographic areas. The lateral continuity of such resource plays means that aside from wells abandoned due to mechanical issues, the Company does not expect to drill many unsuccessful wells as it develops these resource plays. Resource plays allow the Company the opportunity to gain considerable operational efficiencies through high-density, repeatable drilling and completion operations. The Company believes it has a large inventory of lower-risk, predictable development drilling locations across its acreage holdings in the onshore U.S. that provide a solid base for growth in organic production and reserves.

While historically a natural gas producer, in recent years the Company has increased its focus on growing the relative proportion of oil and NGL production in its exploration and production (E&P) business. During 2015, QEP Energy increased oil production by 14% compared to 2014. Additionally, oil and NGL production represented 45% of total production during the year ended December 31, 2015, compared to 44% during the year ended December 31, 2014, and 29% during the year ended December 31, 2013.

QEP Marketing Segment

Effective January 1, 2016, QEP terminated its contracts for resale and marketing transactions between its wholly owned subsidiaries, QEP Marketing and QEP Energy. As a result, QEP Energy will market its own gas, oil and NGL production. In addition, substantially all of QEP Marketing's third-party purchase and sale agreements and gathering, processing and transportation contracts have been assigned to QEP Energy, except those contracts related to natural gas storage activities and Haynesville gathering system (Haynesville Gathering). The change in affiliate transactions will simplify our business processes and financial statements by eliminating the majority of intercompany transactions. QEP also conducted a segment analysis in accordance with Accounting Standards Codification (ASC) Topic 280, Segment Reporting, and based on the changes discussed above, determined that QEP has one reportable segment after January 1, 2016. The elimination of the affiliate transactions has no impact to historical net income. However, since revenues and expenses were historically reported gross for working interest owner products in accordance with principal-agent considerations, QEP will report lower resale revenue and expenses in future periods.

The remaining third party resale activity will be reported in “Other revenues” and "Gathering and other expense" on the Consolidated Statement of Operations.

Discontinued Operations

On December 2, 2014, the Company closed the sale of 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 QEP Field Services Company (QEP Field Services) reporting segment, excluding the retained ownership of Haynesville Gathering, was classified as a discontinued operation on the Consolidated Statement of Operations and the Notes accompanying the

Consolidated Financial Statements. For reporting purposes, Haynesville Gathering has been added to the QEP Marketing and Other segment.

Acquisitions

During the year ended December 31, 2015, QEP acquired various oil and gas properties primarily in the Williston and Permian basins for a total purchase price of $98.3 million, which included an acquisition of additional interests in QEP's operated wells and undeveloped acreage.

On February 25, 2014, QEP Energy acquired oil and gas properties in the Permian Basin of Texas for an aggregate purchase price of $941.8 million (the Permian Basin Acquisition). The acquired properties consisted of approximately 26,500 net acres of producing and undeveloped oil and gas properties and approximately 270 vertical producing wells in the Permian Basin, which created a new core area of operation for QEP Energy.

While QEP believes its extensive inventory of identified drilling locations provide a solid base for growth in production and reserves, the Company continues to evaluate acquisition opportunities that it believes will create significant long-term value. QEP believes that its experience, expertise, and presence in its core operating areas, combined with a low-cost operating model and financial strength, enhance its ability to pursue acquisition opportunities.

Divestitures

The Company periodically divests select non-core assets. In 2015, QEP sold its interest in certain non-core properties in the Midcontinent and Other Northern areas for aggregate proceeds of $31.7 million. In 2014, QEP sold its interest in certain non-core properties in southern Oklahoma, the Midcontinent and the Williston Basin for aggregate proceeds of approximately $783.8 million. In 2013, QEP divested of certain non-core properties in the Midcontinent and Northern Regions resulting in aggregate proceeds of $205.8 million.

Financial and Operating Highlights

Our financial and operating highlights for 2015 are as follows:

- Achieved record equivalent production of 326.8 Bcfe, a 1% increase over 2014;
- Increased oil production to 19.6 MMbbls, a 14% increase over 2014, including 76% growth in the Permian Basin and 13% growth in the Williston Basin;
- Increased natural gas production to 181.1 Bcf, including record production in Pinedale;
- Generated a net loss of $149.4 million, or $0.85 per diluted share;
- Generated $1,029.3 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), of which $1,027.1 million was contributed by QEP Energy;
- Incurred capital expenditures (excluding property acquisitions) of $1,011.9 million, a 41% reduction from 2014;
- Reduced general and administrative expenses by $23.3 million, or 11%;
- Received field-level prices that were 42% lower than in 2014, however, our commodity derivative contracts offset 19% of this decrease; and
- Maintained $376.1 million in cash and cash equivalents and had no borrowings under our revolving credit facility.

Outlook

In response to the commodity price environment, in 2015 we reduced drilling and completion activities, slowed production growth, reduced costs and preserved our liquidity. We plan to continue these strategies in 2016. We are focused on driving improved operating performance by optimizing reservoir development, enhancing well completion designs, and aggressively pursuing cost reductions.

Based on current commodity prices, we expect to be able to fund our planned capital program with cash on hand, operating cash flow and availability under the credit facility. Our total capital expenditures for 2016 are expected to be approximately $475.0 million, a decrease of over 50% from 2015 capital expenditures. With this capital program we expect total equivalent production to be relatively flat compared to 2015. We plan to continuously evaluate our level of drilling activity in light of both commodity prices and changes we are able to make to our costs of operations and adjust our capital spending program as appropriate. See "Cash Flow from Investing Activities" for further discussion of our capital expenditures. We will also continue to pursue acquisitions and divest of non-core properties.

Factors Affecting Results of Operations

Gas, Oil and NGL Prices
Changes in the market prices for gas, oil and NGL directly impact many aspects of QEP's business, including its financial condition, revenues, results of operations, planned drilling activity and related capital expenditures, liquidity, rate of growth, costs of goods and services required to drill, complete and operate wells, and the carrying value of its oil and natural gas properties. Historically, field-level prices received for QEP's gas, oil and NGL production have been volatile and unpredictable, and that volatility is expected to continue.

In recent years, domestic crude oil and natural gas supplies have grown dramatically, driven by advances in drilling and completion technologies, including horizontal drilling and multi-stage hydraulic fracturing. These changes have allowed producers to extract increased quantities of hydrocarbons from shale, tight sand formations, and other unconventional reservoirs. Increased natural gas supplies, particularly in the eastern portion of the country, have resulted in downward pressure on U.S. natural gas prices and a high degree of pricing variability among different regional natural gas pricing hubs. High natural gas demand in 2014, driven primarily by unusually cold winter weather, resulted in improved natural gas prices in the first half of 2014, but continued growth in production, a more normal winter during the 2014-2015 heating season, and adequate storage levels led to natural gas price declines later in the year, which continued throughout 2015 and into 2016. Similarly, growth in U.S. oil production, global crude oil supplies that exceed global demand, a strong U.S. dollar and the failure of the Organization of Petroleum Exporting Countries (OPEC) countries to cut production, led to a dramatic weakening of global oil prices starting in late 2014, which continued throughout 2015 and into 2016.

NGL prices have also been affected by increased U.S. hydrocarbon production and insufficient domestic demand and export capacity. Prices of heavier NGL components, typically correlated to crude oil prices, have declined consistently with weakening oil prices, while ethane and propane prices have experienced greater declines as a result of growing North American oversupply. In addition, QEP's NGL prices are affected by ethane recovery or rejection. When ethane is recovered as a discrete NGL component instead of being sold as part of the natural gas stream, the average sales price of an NGL barrel decreases as the ethane price is generally lower than the prices of the remaining NGL components. As permitted in some of its processing agreements, QEP recovers ethane when gas processing economics support the recovery of ethane from the natural gas stream. When gas processing economics do not support ethane recovery and processing agreements permit it to do so, QEP rejects ethane from the NGL stream.

During 2015, commodity prices were volatile as the NYMEX WTI oil monthly average spot price was as high as $59.82 per barrel in June 2015 and as low as $37.19 per barrel in December 2015, and the NYMEX HH natural gas one-month future price was a high of $3.08 in January 2015 and a low of $2.06 per MMBtu in November 2015. During 2014, the NYMEX WTI oil monthly average spot price was as high as $105.79 per barrel in June 2014 and as low as $59.29 per barrel in December 2014, while the NYMEX HH natural gas one-month future price was as high as $5.15 per MMBtu in February 2014 and as low as $3.65 per MMBtu in November 2014.

Due to increased global economic uncertainty and the corresponding volatility of commodity prices, QEP has built a strong liquidity position to ensure financial flexibility and has reduced drilling and completion activity and planned capital expenditures. 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, 2015, assuming forecasted 2016 annual production of approximately 314 Bcfe, QEP Energy had approximately 51% of its forecasted gas equivalent production covered with fixed-price swaps, including 71% of its forecasted gas production and 34% of its forecasted oil production. QEP entered into additional derivative contracts in 2015 and early 2016, but the average swap price of its derivative portfolio is significantly lower than the contracts entered into prior to 2015 and, therefore, will not contribute as much to QEP's net realized prices for future production. 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.

Global Geopolitical and Macroeconomic Factors

QEP continues to monitor the global economy, including Europe's economic outlook; political unrest in Eastern Europe, the Middle East, and Africa; slowing growth in Asia, particularly in China; the United States' federal budget deficit; changes in regulatory oversight policy; commodity price volatility; the impact of rising 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 gas, oil and NGL supply, demand and prices and the Company's ability to continue its planned drilling programs on federal and Native American lands and could materially impact the Company's financial position, results of operations and cash flow from operations.

Supply, Demand and Other Market Risk Factors

Increased oil production in the U.S. over the last five years combined with various other global factors have led to substantially lower oil prices. According to data from the Energy Information Administration (EIA), U.S. oil production has increased by approximately four million barrels per day, or approximately 70%, since 2011. International oil supply disruptions in previous years have prevented oversupply and a corresponding negative price impact, but reduced supply disruptions combined with softening global demand, a stronger U.S. dollar, and other factors have led to substantially lower oil prices starting in late 2014 that have continued throughout 2015 and into 2016. As a result, many oil producers around the world are dramatically reducing activity.

In December 2015, the U.S. lifted a 40-year ban on the export of crude oil. U.S. producers now have access to a wider market, and the U.S. could become a significant exporter of oil if the necessary infrastructure is built to support oil exports. As a result, oil and gas prices in the future may be cheaper than they would otherwise be. QEP anticipates global oil prices will improve in the coming years as supply growth moderates due to lower level of investment and modest demand increases. 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.

During the last five years, the U.S. natural gas directed drilling rig count has decreased as producers reduced drilling activity for dry natural gas in response to lower natural gas prices and directed investment toward oil and liquid-rich projects. Over the same period of time, U.S. natural gas production has continued to grow, particularly in the Marcellus Shale region, as efficiency gains have allowed more wells to be drilled and completed per operating rig, higher per-well natural gas production from horizontal wells as a result of investment focused on more prolific resources, and increased amounts of natural gas produced in association with crude oil. As a result, U.S. natural gas production continued to increase into 2015, despite the gradually decreasing rig-count. Strong natural gas demand from electric power generation, cold winter weather during the 2013-2014 heating season, and other demand sources caused a general firming of natural gas prices during the second half of 2013 and into the first half of 2014. Natural gas prices weakened in the second half of 2014 and continued to decline throughout 2015 and into 2016 due to more typical winter season demand levels and continued increases in supply. QEP expects U.S. natural gas prices to remain range-bound over the near term. Relatively low natural gas prices in recent years have caused U.S. E&P companies, including QEP, to shift capital investments away from predominantly dry gas areas toward plays that produce crude oil, condensate and liquids-rich gas.

The reallocation of drilling capital to liquids-rich gas and crude oil has caused domestic NGL production to increase dramatically. Increased NGL production has contributed to a weakening of domestic NGL prices, particularly ethane and propane. QEP expects that ethane prices will continue to be range-bound and ethane processing economics challenged until new ethylene crackers and export facilities are built. Propane prices have declined as a result of abnormally high inventory levels, limited domestic demand growth and insufficient export capacity. The prices of heavier components of the NGL barrel have weakened as a result of the decline in crude oil prices.

In addition, transportation, refining, or other infrastructure constraints could introduce significant price differentials between regional markets where QEP sells its production and national (NYMEX HH at Henry Hub or NYMEX WTI at Cushing) and global (ICE Brent) markets. Because of the global and regional price volatility and the uncertainty around the gas, oil and NGL price environments, QEP continues to manage its capital spending program and liquidity accordingly and has scaled back its capital expenditure budget and drilling and completion activities planned for 2016.

Potential for Asset Impairments

The carrying value of the Company's properties is sensitive to declines in gas, oil and NGL prices. These assets are at risk of impairment if future prices for gas, oil or NGL decline and/or drilling and completion costs increase. The cash flow model that the Company uses to assess proved properties for impairment includes numerous assumptions, such as management's estimates of future gas, oil and NGL production, market outlook on forward commodity prices, operating and development costs, and discount rates. All inputs to the cash flow model must be evaluated at each date of estimate. Forward prices in mid February

2016 have declined subsequent to the test for impairment at December 31, 2015. If forward prices remain at mid February 2016 levels, we have approximately $1.8 billion of proved property net book value, as of December 31, 2015, primarily associated with our Pinedale field, 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. Additionally, a further decrease from mid February levels in forward gas, oil or NGL prices could result in additional properties being at risk for impairment.

During the year ended December 31, 2015, the Company recorded impairments of $55.6 million primarily due to impairments of proved properties and goodwill associated with lower future prices. During the year ended December 31, 2014, impairments were $1,143.2 million primarily due to impairments of proved property in the Southern Region associated with lower future prices at December 31, 2014. During the year ended December 31, 2013, impairments were $93.0 million primarily due to impairments of goodwill and unproved properties associated with expiring leases and future development plans. For additional information see Item 1A – Risk Factors, of Part I and see Item 8 of Part II, Note 1 – Summary of Significant Accounting Policies, of this Annual Report on Form 10-K.

Multi-Well Pad Drilling

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. In certain of our producing areas, 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 completion process. As a result, multi-well pad drilling delays the commencement of production, which may cause volatility in QEP’s quarterly operating results.

RESULTS OF OPERATIONS

Our financial results for prior periods have been revised, in accordance with GAAP, to reflect the impact of the Midstream Sale. See Note 3 – Discontinued Operations, in Item 8 of Part II of this Annual Report on Form 10-K for detailed information on the Midstream Sale.

Net Income

The following table provides a summary of net income (loss) by line of business:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions, except per share amounts)				
QEP Energy	$(182.9)	$(432.5)	$25.6	$249.6	$(458.1)
QEP Marketing and Other	33.5	23.0	26.5	10.5	(3.5)
Net income (loss) from continuing operations	(149.4)	(409.5)	52.1	260.1	(461.6)
Net income from discontinued operations, net of income tax	—	1,193.9	107.3	(1,193.9)	1,086.6
Net income (loss)	$(149.4)	$784.4	$159.4	$(933.8)	$625.0
Earnings (loss) per diluted share from continuing operations	$(0.85)	$(2.28)	$0.29	$1.43	$(2.57)
Earnings per diluted share from discontinued operations	—	6.64	0.60	(6.64)	6.04
Diluted earnings (loss) per share	$(0.85)	$4.36	$0.89	$(5.21)	$3.47

Average diluted shares	176.6	179.8	179.5	(3.2	) 0.3

QEP generated a net loss from continuing operations during the year ended December 31, 2015, of $149.4 million, or $0.85 per diluted share, compared to a net loss from continuing operations of $409.5 million, or $2.28 per diluted share, in 2014. The decrease in net loss for the year ended December 31, 2015 compared to the year ended December 31, 2014, was due to a $249.6 million decrease in QEP Energy's net loss and a $10.5 million increase in QEP Marketing and Other's net income. QEP Energy's decrease in net loss was primarily due to a decrease in impairment expense of $1,087.6 million, a 14% increase in oil production, a slight increase in gas production, a net gain from asset sales of $9.7 million during 2015 compared to a net loss from asset sales of $148.6 million during 2014 and lower operating expenses during the year ended December 31, 2015 compared to the year ended December 31, 2014. These changes were partially offset by a decrease in average field-level prices for gas, oil and NGL, a 31% decrease in NGL production and a $93.0 million decrease in realized and unrealized gains on derivative contracts. QEP Marketing and Other's net income increased during the year ended December 31, 2015 compared to 2014, primarily due to lower interest expense due to lower average debt levels during the year ended December 31, 2015, and a decrease in net loss from resale margin.

QEP generated a net loss from continuing operations during the year ended December 31, 2014, of $409.5 million, or $2.28 per diluted share, compared to net income from continuing operations of $52.1 million, or $0.29 per diluted share, in 2013. The net loss during 2014 was due to a decrease $458.1 million at QEP Energy and a decrease of $3.5 million at QEP Marketing and Other. The net loss at QEP Energy during 2014 was primarily attributable to an increase in impairment expense of $1,050.2 million related to higher impairments in 2014, a loss on sale of assets of $148.6 million in 2014 compared to a gain on sale of $104.1 million in 2013 and lower realized gains on derivative contracts of $150.8 million. These additional expenses incurred at QEP Energy during 2014 were partially offset by an increase in unrealized gains on derivative contracts of $458.9 million and increased oil revenue of $451.6 million due to a 68% increase in oil production. QEP Marketing and Other's net income is related to intercompany interest income from interest expense charges to QEP's subsidiaries.

Adjusted EBITDA

Management believes Adjusted EBITDA (a non-GAAP measure) is an important measure of the Company's financial and operating performance that allows investors to understand how management evaluates financial performance to make operating decisions and allocate resources. 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, and certain other non-cash and/or non-recurring items.

The following table provides a summary of Adjusted EBITDA by line of business:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
QEP Energy	$1,027.1	$1,437.0	$1,301.8	$(409.9)	$135.2
QEP Marketing and Other	2.2	1.3	14.2	0.9	(12.9)
Adjusted EBITDA from continuing operations	1,029.3	1,438.3	1,316.0	(409.0)	122.3
Adjusted EBITDA from discontinued operations	—	144.4	220.7	(144.4)	(76.3)
Adjusted EBITDA	$1,029.3	$1,582.7	$1,536.7	$(553.4)	$46.0

Adjusted EBITDA from continuing operations decreased to $1,029.3 million during the year ended December 31, 2015 compared to $1,438.3 million in 2014, due to a 42% decrease in the average field-level price and a 31% decrease in NGL production, partially offset by a 14% increase in oil production, a slight increase in gas production and higher realized gains on derivative contracts.

Adjusted EBITDA from continuing operations increased to $1,438.3 million during the year ended December 31, 2014 compared to $1,316.0 million in 2013, due to a 68% increase in oil production and a 41% increase in NGL production, partially offset by an 18% decrease in gas production and a 10% and 18% decrease in oil and NGL net realized prices, respectively, at QEP Energy.

The following tables are reconciliations of Adjusted EBITDA to net income (loss) attributable to QEP, the most comparable GAAP financial measure, for the years ended December 31, 2015, 2014 and 2013:

	QEP Energy	QEP Marketing and Other [1]	Continuing Operations	Discontinued Operations	QEP Consolidated
	(in millions)				
Year ended December 31, 2015					
Net income (loss)	$(182.9)	$33.5	$(149.4)	$—	$(149.4)
Unrealized (gain) loss on derivative contracts	182.9	0.8	183.7	—	183.7
Net (gain) loss from asset sales	(9.7)	5.1	(4.6)	—	(4.6)
Interest and other income	(1.9)	(1.1)	(3.0)	—	(3.0)
Income tax provision (benefit)	(105.9)	12.3	(93.6)	—	(93.6)
Interest expense (income)	204.5	(58.9)	145.6	—	145.6
Pension curtailment[2]	11.0	0.2	11.2	—	11.2
Depreciation, depletion and amortization	870.8	10.3	881.1	—	881.1
Impairment	55.6	—	55.6	—	55.6
Exploration expenses	2.7	—	2.7	—	2.7
Adjusted EBITDA	$1,027.1	$2.2	$1,029.3	$—	$1,029.3
Year ended December 31, 2014					
Net income (loss)	$(432.5)	$23.0	$(409.5)	$1,193.9	$784.4
Unrealized (gain) loss on derivative contracts	(368.2)	(6.2)	(374.4)	—	(374.4)
Net (gain) loss from asset sales	148.6	—	148.6	(1,793.4)	(1,644.8)
Interest and other income	(11.8)	(1.0)	(12.8)	(0.3)	(13.1)
Income tax provision (benefit)	(246.9)	14.4	(232.5)	708.2	475.7
Interest expense (income)[3]	210.3	(41.2)	169.1	2.3	171.4
Loss on early extinguishment of debt	—	2.0	2.0	2.4	4.4
Depreciation, depletion and amortization[4]	984.4	10.3	994.7	31.3	1,026.0
Impairment	1,143.2	—	1,143.2	—	1,143.2
Exploration expenses	9.9	—	9.9	—	9.9
Adjusted EBITDA	$1,437.0	$1.3	$1,438.3	$144.4	$1,582.7
Year ended December 31, 2013					
Net income (loss)	$25.6	$26.5	$52.1	$107.3	$159.4
Unrealized (gain) loss on derivative contracts	90.7	(2.0)	88.7	—	88.7
Net (gain) loss from asset sales	(104.1)	0.6	(103.5)	0.5	(103.0)
Interest and other income	(3.6)	(11.6)	(15.2)	10.0	(5.2)
Income tax provision (benefit)	41.5	18.6	60.1	59.7	119.8
Interest expense (income)[3]	192.6	(27.5)	165.1	(2.2)	162.9
Depreciation, depletion and amortization[4]	954.2	9.6	963.8	45.4	1,009.2
Impairment	93.0	—	93.0	—	93.0
Exploration expenses	11.9	—	11.9	—	11.9
Adjusted EBITDA	$1,301.8	$14.2	$1,316.0	$220.7	$1,536.7

(1) Includes intercompany eliminations.

(2) The pension curtailment was a non-cash expense incurred during the year ended December 31, 2015, due to changes in the Company's pension plan (see Note 12 – Employee Benefits, in Item 8 of Part II of this Annual Report on Form 10-K for additional information). The Company believes that the pension curtailment does not reflect expected future operating performance or provide meaningful comparisons to past operating performance and therefore has excluded the loss from the calculation of QEP's Adjusted EBITDA.

(3) Excludes noncontrolling interest's share of $1.5 million and $0.4 million during the years ended December 31, 2014, and 2013, respectively, of interest expense attributable to QEP Midstream.

(4) Excludes noncontrolling interests' share of $14.6 million and $6.8 million during the years ended December 31, 2014, and 2013, respectively, of depreciation, depletion and amortization attributable to Rendezvous Gas Services, L.L.C and QEP Midstream.

QEP ENERGY

The following table provides a summary of QEP Energy's financial and operating results:

	Year Ended December 31,			Change	
	2015	2014	2013	2015 vs 2014	2014 vs 2013
	(in millions)				
REVENUES					